# FOREWORD

The natural gas industry worldwide is facing fundamental change as a result of government reforms to regulatory systems aimed at increased efficiency through the establishment of competition in the supply of gas. This restructuring, involving the sweeping away of many of the monopolistic features of the industry, is having a profound impact on the way gas is bought and sold and the underlying economics of gas price determination. This report, the result of an in-depth IEA study, aims to provide industry players and policy makers alike with a better understanding of that process and of the critical success factors in establishing an efficient, competitive market. It complements other recent IEA reports on natural gas, including the *IEA Natural Gas Distribution Study*, published in 1998, and the *IEA Natural Gas Security Study*, published in 1995.

This analysis draws heavily on the experience of pioneering gas sector reforms in North America, where the process first began in the 1970s, and in Great Britain, where reforms launched in the 1980s have arguably gone furthest. Despite significant differences between these markets, there appear to be a number of common features of the way gas is priced under competition and the development of new trading arrangements and relationships. These include the growth of short-term trading, the development of spot and futures gas price escalation in medium and long-term contracts (as in the oil industry), the demise of long-term take-or-pay commitments, a growing emphasis on risk management and convergence between the gas and electricity sectors. These developments and characteristics provide pointers to the way in which gas markets will develop in other countries embarking on structural reforms, though the precise outcome in each instance will depend to a large extent on the regulatory approach adopted, which in turn will reflect specific national circumstances, including institutional characteristics.

The principal author of this study is Trevor Morgan. Elizabeth Kuhlenkamp, now with NYMEX, helped with the preparation of the North American case study. Caroline Varley managed and Jean-Marie Bourdaire directed the project. The IEA Secretariat would like to place on record its gratitude for invaluable comments and information it received from Member countries and industry contacts.

The book is published on my authority as Executive Director of the IEA.

**Robert Priddle**
**Executive Director**

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# EXECUTIVE SUMMARY

A number of countries have launched or are about to launch structural reforms of natural gas markets involving the introduction of gas-to-gas competition. These reforms, often taking place in parallel with electricity sector reforms, are part of a much broader economic restructuring process aimed at improving economic efficiency through greater reliance on market forces and less direct intervention from Government. Gas market reforms already implemented have brought major economic benefits in the form of increased efficiency in the provision of transportation and marketing services, more market-driven investment decisions, a broader range of services and lower prices to most consumers.

The United States and Canada were the first countries to initiate gas sector reforms in the late 1970s and early 1980s. This began with the removal of wellhead price controls and later the introduction of competition in wholesale[1] gas supply through unbundling of gas trading and transportation services and mandatory third party access to interstate pipelines. Market reforms were launched in Great Britain in the 1980s, but have been taken further than in North America with the extension of third-party access to the entire network including local distribution and retail competition to all end users, even households. Some other European countries, including the Netherlands, Spain and Germany, started to implement reforms in the early- to mid-1990s. Initial agreement on a European Union gas directive at the end of 1997 and the commissioning of the Interconnector between the United Kingdom and continental Europe in late 1998 are expected to pave the way for a more extensive market opening across Europe in the first decade of the next century.

The North American and British markets — considered in detail in this report — are characterised by competition in supply, based on mandatory and non-discriminatory open access to the pipeline infrastructure. While gas prices, at least at the wellhead and at the bulk or wholesale level, have been decontrolled in these markets, the prices of transportation and storage services (which make up part of final end-user prices) remain for the most part tightly regulated by governmental authorities on a cost-of-service basis. The precise regulatory approach and framework, nonetheless, varies.

The emergence of gas-to-gas competition based on the introduction of mandatory third-party access engenders fundamental changes in the gas market. The unbundling of gas commodity supply and trading from transportation and related services, and the removal of gas price controls revolutionises the way gas is traded, including the mechanisms used to price gas in contracts. In North America and Britain, this process has involved *inter alia:*

1. Wholesale refers to sales of gas to parties other than end-users (marketers and local distribution companies); retail refers to sales to end-users of gas, including sales of gas to large end-users supplied directly off the high pressure transmission system.

- A diversification of the range of services available to wholesale and retail buyers.

- A huge increase in the number and complexity of transactions which has triggered major investment by all players in sophisticated computerised information and communication systems.

- The emergence of financial risk management instruments including futures and options contracts.

- A shift from long-term to short-term trading in transportation and related services and the supply of the gas commodity itself (on spot and futures markets).

- A move towards spot and futures gas price indexation in mid- and long-term supply contracts.

As with any commodity, gas prices in a competitive market are determined by the interplay of supply and demand. The key difference between monopoly and competitive pricing of gas is that, in a properly functioning free market, there is only ever one prevailing market price for the commodity at a given location; a monopoly, by contrast, may set the price in a discriminatory way for each end-use customer according to its demand characteristics. Where there are no pipeline capacity constraints, differences in market prices across regions in a truly competitive market must reflect the actual cost of moving gas between locations. The cost of transportation is determined either by the regulated tariff or by the secondary (release) market rate, where secondary capacity trading is allowed (which is the case in the markets covered in this report). Where competition through third-party access is confined to the high-pressure transmission system (as in the United States), the market sets the retail gas price delivered to large end-users supplied directly from the transmission system and the bulk or wholesale price at the city gate to local distribution companies (LDCs). The pricing policy of the LDC and price controls imposed by national or local regulators will determine the mark-up (gross margin) on the city gate price and the structure of retail prices to LDC customers. Where competition is extended to all retail customers, as in Britain, end-user prices will tend to reflect the bulk market price (at the wellhead, beach or border) plus the cost of transportation and distribution (including any customer service costs) to each end-user location.

How relevant the experiences of North America and Britain are to other countries is unclear. While the general principles of gas trading and price setting have universal applicability, there can be important differences between markets in terms of the number of suppliers, the dependence on external suppliers and the maturity of the network. These factors, and such other concerns as public service commitments and job protection, explain the hesitation shown so far by most European countries in introducing competition based on third-party access and the relatively limited degree of market opening provided for in the recently agreed EU gas directive. Despite these uncertainties, the gradual opening up of the European gas market is likely to be accompanied sooner or later by the development of spot and futures markets (initially driven by gas sales through the Interconnector), a move towards spot gas price indexation in mid- and long-term contracts, optimisation of daily and seasonal load balancing, and the convergence of natural gas and power markets.

There is no catch-all prescriptive model for the process of regulatory reform and restructuring, nor the ultimate regulatory framework, once competition has been established. Policy makers and regulators need to take account of specific national circumstances, including the physical characteristics of the pipeline and upstream infrastructure, the ownership structure of the industry and market trends. Nonetheless, important lessons can be learnt from experiences in competitive gas pricing in North America and Britain:

- The effective separation (unbundling) of the management and accounting of the pipeline and storage functions on the one hand and the gas supply and trading activities of gas companies on the other is crucial to ensuring non-discriminatory third-party access and efficient regulation.

- Transparency in the non-price terms and conditions of access to the pipeline system and storage facilities is also a key factor in preventing discrimination between shippers (including, in particular, the pipeline company's own marketing body), encouraging access and competition, and ensuring efficient operation of the industry.

- In most cases, pipelines are natural monopolies; encouraging competition in the provision of these services is generally not economically efficient. Some form of rate-of-return or tariff regulation is, therefore, usually necessary to prevent pipeline companies from overcharging for use of their systems and enjoying monopoly rent.

- Whatever the precise approach to regulation adopted, responsibility for regulation needs to be clearly defined and vested in an appropriate governmental body, independent of market players.

- There is a role for Government in enhancing both short- and long-term gas security, by facilitating international trade and investment including pipeline interconnections, by determining acceptable security levels for small consumers and safety requirements, and by providing a legal basis for dealing with emergencies.

# PART I

# NATURAL GAS PRICING UNDER COMPETITION

# 1

# INTRODUCTION

This report sets out the findings of an IEA study on competitive pricing of natural gas. The objective of the study is to assess the impact of the introduction of competition in the gas sector on contractual gas-pricing mechanisms. It also considers the economics of gas price determination with reference to case studies of countries with experience of competitive gas markets. The study aims to contribute to a better understanding of the market implications of gas-sector regulatory reform and restructuring, and the critical success factors in establishing an efficient, competitive market.

Specific elements of the study include:

- Comparative assessment of gas sector regulation and reform.
- Analysis of developments in gas-pricing mechanisms and contractual arrangements.
- Quantitative analysis of short- and long-term price determination, including the role of interfuel and gas-on-gas competition.
- Assessment of the relevance of actual experience with competitive gas markets to countries considering or embarking on gas sector reforms.

Canada, the United States and Great Britain[2] were selected for the case studies. Canada and the United States are considered jointly because of the strong links between their markets, in terms of physical connections, regulatory compatibility and market dynamics. Although liberalisation of the gas sector is proceeding in a number of countries, these three have the longest experience and have taken reforms furthest.

Although this study is not intended to set out the case for competition in natural gas, analysis of the North American and British markets yields considerable evidence of the benefits of regulatory reform in the form of an increased range of services available to end-users and lower prices. Over the past ten years, average gas prices to end users in these markets have held stable or fallen, while volumes delivered have increased (see Part II). This suggests that gas is being produced, transported and delivered more efficiently than in the past and that the benefits of this improvement are flowing through to consumers. The apparent success of these reforms has prompted many other countries to pursue similar policies, though the precise approach being adopted in each instance reflects specific national circumstances, including institutional characteristics.

2. England, Scotland and Wales.

The purpose of Part I of this report is to set out some of the basic principles of gas pricing and the economics of gas-price determination in a competitive market. Gas markets differs from most other commodity markets in important ways (see box), although there are similarities with electricity and other network industries. The critical feature of most gas markets is the cost and nature of transportation: moving gas from the point of production to the point of use is highly capital-intensive, expensive relative to the cost of the commodity itself and characterised by important economies of scale. These features are most marked at the distribution stage of the gas supply chain.

### Why Natural Gas Markets are Different from other Commodity Markets

- Gas can be bought and sold like any other good, but its transportation is in most cases a natural monopoly: it is generally inefficient to build competing networks — particularly for local distribution — because of economies of scale, although some aspects of operating the network may not be monopolistic, e.g. metering. Thus, the supply of gas to end users will in most cases always involve an element of monopoly — even in a competitive market. Government has a responsibility to regulate natural monopolies to prevent abuse of market position.

- Gas prices in a competitive market may diverge considerably in the short and long run. In the short term, prices will mostly be determined by the marginal value of gas in end-user markets. Storage may provide sellers an opportunity to hold gas off the market when end-user demand and/or prices are low. Prices will, in principle, tend to oscillate around long-run marginal cost, which includes a large element of upfront capital expenses.

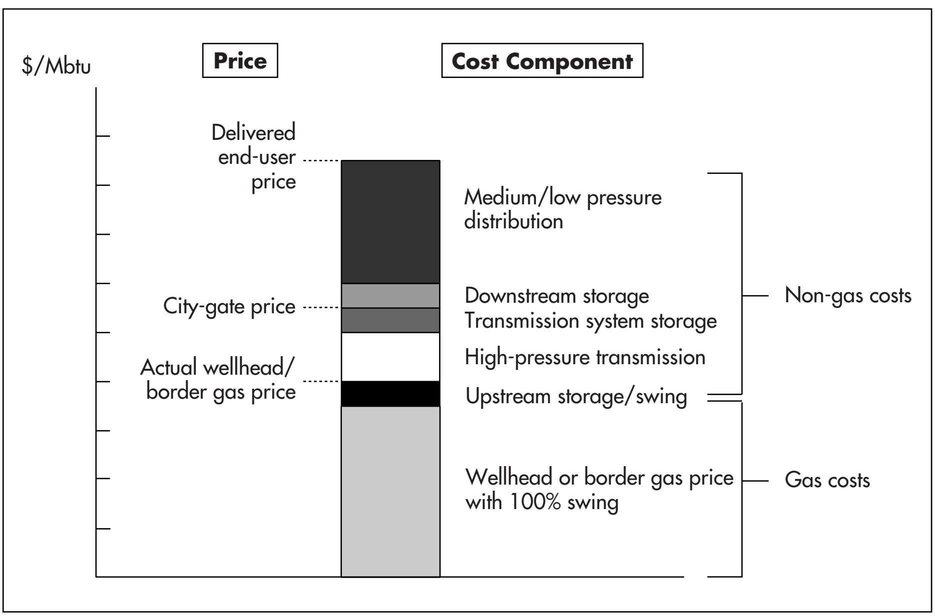
- End-user demand for gas for heating (mainly in the residential and commercial sectors) and to some extent in power generation (where there is significant heating or cooling load) is strongly correlated to the weather.

- Many gas customers are captive, since they have no immediate alternative to using gas, so that overall demand may be price inelastic in the short term. Captive customers require uninterrupted supply at all times. Demand seasonality imposes additional supply costs. Non-captive customers with the ability to switch fuels or plant may be supplied under interruptible contracts, allowing supplies to be diverted to captive customers at times of peak demand.

The different models of competition in natural gas supply and approaches to regulation are outlined in the next section. For the purposes of the rest of the study, we define a truly competitive market as one in which there is mandatory and non-discriminatory open access to the pipeline infrastructure, at least at the transmission level. All three countries considered in this study have competitive gas markets thus defined, although only in Britain has retail competition been fully extended to the entire network including local distribution so that all end-users are free to choose their supplier. Moves to introduce full retail competition in Canada and the United States are underway.

It is important to emphasise that competition in these markets refers to the supply of gas as a commodity, not the provision of transportation and related services. While retail gas prices, at least at the bulk or wholesale level, have been decontrolled in these markets, the prices of transportation services (which make up part of final end-user prices) remain regulated by governmental authorities. The precise regulatory approach and framework varies. Figure 1 summarises the different cost components in average end-user gas prices, each of which includes a profit margin. The relative importance of these components in any given country is determined by a number of factors including the distance from supply source to delivery point, the type of regulation and cost allocation, the load profile of the end user and the degree of gas-to-gas competition. The share of unregulated gas costs will generally be lower for small-load, low-load-factor customers (usually well under half of the total end-user selling price). For large-volume, high-load-factor end users, the share of border or wellhead gas costs may be very high.

*Figure 1*
**Cost Breakdown of Average End-User Gas Price**




The introduction of competition in natural gas markets in North America and Britain has led to changes in the structure of gas prices and reductions, on average, in real pre-tax prices in parallel with rising volumes delivered. Consumer choice, including the range of services on offer, has expanded. These trends suggest that gas is being produced, transported and delivered more efficiently and that these efficiency improvements are flowing directly to end users.

The implications of competition for the way in which the supply of the gas commodity and transportation services are contracted and the pricing mechanisms used in contracts are examined in section 3. Section 4 considers the way in which competition changes how prices are set, including the role of interfuel competition and short-term fuel switching. Part I concludes with a discussion of how applicable the experiences of competitive gas pricing in the countries analysed in detail in this report are to other countries, particularly in Europe, and a short review of the broad lessons for policy makers and regulators. Part II contains the case studies of gas pricing in North America and Britain.

**2**

# COMPETITION AND REGULATION IN THE GAS SECTOR

## THE GLOBAL TREND TOWARDS COMPETITION IN THE GAS SECTOR

Many countries have launched or are about to launch structural reforms of natural gas markets promoting gas-to-gas competition. These reforms are part of a much broader restructuring process aimed at improving economic efficiency through greater reliance on market forces and less direct intervention by Government. The pressure for a more competitive gas market in most countries has tended to increase as the markets have matured. Monopoly is commonly regarded as appropriate during the early stages of a gas industry, because of high marginal costs, the technical and financial risks, and the low returns intrinsic to the business (see box). Once the large capital investment in infrastructure has been largely depreciated, marginal costs and risks fall and returns tends to rise. The lack of transparency in the pricing of bundled gas and transportation services, coupled with the spectacle of very high profits, tends to lead to pressure for government action (in the form of tighter regulation and/or more competition). The pressure comes from gas producers and consumers and other energy providers deprived of the opportunity to share in the economic rent.

Structural reforms began in North America in the 1950s with the growth of detailed regulation in all aspects of the business, including controls on wellhead gas prices. The excessive reliance on heavy Federal and state/provincial regulation contributed to gross market distortions and supply shortages in the 1970s. Its evident failure led to a shift in policy towards greater reliance on market forces. This initially involved the removal of wellhead price controls followed by the introduction of competition in wholesale gas supply through the unbundling of gas trading and transportation services and mandatory third-party access to interstate pipelines (see Part II-A).

Market reforms were launched in Britain in the 1980s. By the end of the decade, the Government was actively promoting competition. It restricted the commercial activities of the *de facto* monopoly, British Gas, and ensured that a significant proportion of gas under new and existing contracts was made available to competing suppliers, partly through a mandatory gas-release programme (see Part II-B). Some other European countries, including the Netherlands, Spain and Germany, started tentatively to introduce reforms in the early to mid-1990s. Initial agreement on a European Union gas directive at the end of 1997 and the commissioning of the interconnector between Britain and continental Europe in late 1998 are expected to pave the way for a still more extensive market opening across. New Zealand and Australia have recently launched reforms aimed at establishing competitive markets. Several non-IEA countries in Eastern Europe, Central and Latin America[3] and Asia are introducing or planning similar reforms.

### Competition and Regulation in Nascent Gas Industries

Until now, gas companies setting up a greenfield gas importation and transmission business have generally been granted extensive monopoly rights over transportation and supply within a given area. They have not been required initially to offer pipeline access to third parties. The case for a monopolistic regulatory framework in the early years of the development of the industry is based on the following grounds:

- Such a venture is perceived by most investors as carrying substantial risk, in terms of construction costs and market potential. Given the large initial investment and correspondingly high marginal costs, financing typically hinges on assurances about future pipeline usage. These are normally provided by a combination of long-term contracts with large buyers, such as power plants, and monopoly rights over the supply of gas to customers within a given geographic area (sometimes the entire country).
- A monopoly gas transportation company is generally able to extract monopoly rent, at least in unregulated industrial markets, if the company is able to set gas prices in relation to the competing fuel in each market segment. This type of discriminatory pricing results in average prices that are above those that would occur in a competitive market.
- The higher average price paid for gas compared with the price in a competitive market has been justified by the external benefit accruing to the country from diversified energy supplies. The value of diversity is, however, difficult to quantify.

In practice, governments seeking to promote the development of gas infrastructure from scratch may also use energy taxation to give gas a competitive advantage over other fuels.

There is a wealth of literature concerning the disadvantages of monopoly and the advantages of competition in maximising economic efficiency. Under monopoly, there is no automatic incentive for the players to minimise costs, maximise efficiency and productivity, and reduce prices to consumers. Competition forces them to do these things in order to survive. The establishment of a market structure with competing suppliers and consumers who have the right to exercise

3. Argentina has progressed furthest with gas sector reforms. An IEA review of Argentina's gas sector policy and regulation is in preparation.

choice spurs suppliers systematically to seek out productivity gains and comparative advantages. This is a self-reinforcing process. As energy markets become more competitive and more complex, new forms of competition emerge and industry structures evolve accordingly. As new market entrants appear, they disturb the rules of the game and generate new competitive pressures and commercial initiatives. The drive for economic efficiency leads inevitably to a radical reorganisation of market and industry structure. The way government seeks to meet its social, environmental and supply security objectives also changes in response to these pressures.

## DIFFERENT COMPETITIVE MODELS

There are two main competitive market models which have emerged as alternatives to the basic monopoly structure. These models involve different degrees of market openness and competitive pressure:

- ***A. Pipeline-to-pipeline competition:*** Two or more high-pressure transmission pipeline companies transport gas to the same regional market. They compete for sales to large industrial consumers, power generators and local distribution companies (LDCs) connected directly to those lines. Since LDCs and other large users usually buy gas under long-term contracts, the scope for true competition may be limited. Where only two or three pipelines exist, competitive pressure may be slight. The threat of new pipeline construction may, however, help to limit prices and excess profits, even where prices are not directly regulated. A degree of pipeline-to-pipeline competition exists in Germany, where Wingas competes mainly with Ruhrgas for large-volume sales to industry. There may be some potential for inter-pipeline competition in the United States, particularly between the Gulf region and the Northeast/Middle Atlantic, though the current regulatory framework usually precludes such competition in practice. The incentives that such competition may bring to minimise costs may, in some cases, be offset by the sacrifice of economies of scale.

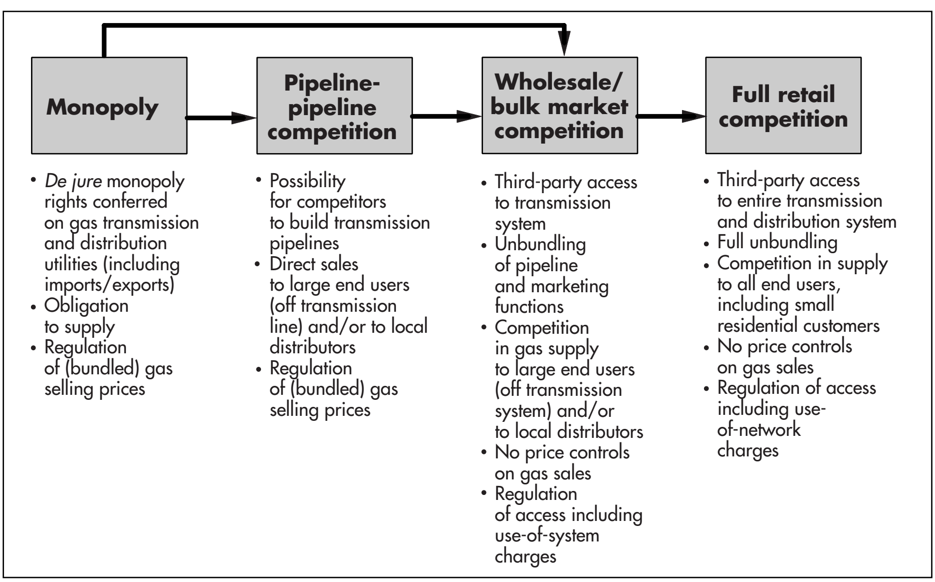
- ***B. Mandatory third-party access to the network:*** In practice, access may cover solely the high-pressure transmission system. It can cover part or all of the regional and local distribution system as well:

  - 1. *Wholesale or bulk market competition:* Non-discriminatory third-party access to the high-pressure transmission system is mandatory. Transportation services are unbundled from the pipeline companies' gas sales activities. Marketing companies, which may include affiliates of pipeline operators, compete for sales to large industrial customers, power stations and LDCs. All market participants have the opportunity in principle to resell gas supplies on a short-term or long-term basis. Bulk gas prices are unregulated. Shippers, which may include producers, traders and end users, are responsible for booking capacity and paying use-of-system charges. Those charges are regulated or capped on a cost-of-service basis, allowing a fair rate of return to the system operator. Wholesale competition has been introduced in the United States, Canada, Australia, New Zealand and Argentina, and is planned to a varying extent in Europe and Mexico.

– 2. *Full retail competition:* Mandatory third-party access is expanded to cover distribution networks as well as the high-pressure transmission system, so that all end users (retail customers) including small consumers are free to choose their supplier. Transportation and gas sales are unbundled at all levels. All gas price controls are removed. At present, the only country that has full competition in gas supply at the retail level based on complete unbundling is the United Kingdom (not including Northern Ireland), but larger end users in the United States and Canada who are supplied off local distribution networks are able to contract separately for gas supply and local distribution services.

These models represent varying degrees and types of competition. Inter-pipeline competition is in principle compatible with supply competition based on third-party access, but no such market structure exists in practice[4]. Full retail competition based on mandatory third-party access to the entire network is the most competitive model. Only the United Kingdom has so far adopted this model. Wholesale competition with third-party access to the transmission system is an intermediate stage in the implementation of full retail competition (see Figure 2).

*Figure 2*
**Stages of Development of Gas-to-Gas Competition**




4. The US regulator, the Federal Energy Regulatory Commission (FERC), is nonetheless beginning to allow the market to play a bigger role in setting tariffs in the small number of cases where effective pipeline-to-pipeline competition is deemed to exist (see Part II-A).

# APPROACHES TO REGULATION

Whatever the chosen competitive model or the degree to which competition is established in the gas sector, some form of government regulation is seen as essential on the following grounds:

- ***Natural monopoly:*** Gas transportation through pipes is considered to be, in most cases, a natural monopoly — particularly in local distribution[5]. Prices charged for transportation services, therefore, need to be controlled to prevent the monopoly service provider from exploiting the potential for excessive profits. Storage may also display natural monopoly characteristics, though geology and market size may allow storage services to be provided efficiently by the market.

- ***Supply security:*** Security of gas supply can be divided into three risk categories: the short-term risk of disruptions to supplies through the failure of markets to balance supply and demand adequately, the long-term risk that inadequate investment will be made to secure future supplies (noting that short-term security ultimately fails if long-term investment fails); and the risk of inadequate diversity of supply sources in the event of a major disruption from a given source. The government or regulator may intervene to manage these risks.

- ***Anti-competitive behaviour by gas marketers:*** There may be concerns about the level of market concentration. A dominant company may seek to stifle competition through predatory pricing, especially in the early stages of competition in gas wholesaling and retailing.

- ***Consumer welfare protection:*** Most governments seek to provide protection to household customers, particularly the poor and disadvantaged.

Whatever the competitive model, regulation of the gas sector by public authorities varies considerably from a light-handed or hands-off approach to one characterised by detailed and onerous constraints on gas company activities. The light-handed approach, as in Germany and New Zealand, places primary reliance on general competition law and anti-trust institutions to address anti-competitive behaviour in an *ex-post-facto* manner. More detailed regulation, as in the United States and Britain, reinforces the foundations provided by competition law with explicit mechanisms to control the behaviour of natural monopoly transporters including pricing and handling of network access as well as financial and operational performance. In the transition from a *de facto* monopoly, regulation may also involve, as in Britain, active measures to nurture the development of competition.

5. The supply of a given commodity may be considered a natural monopoly where economies of scale are such that the costs of supply are lower if there is a single supplier. Energy supply activities that require more or less permanent connections with customer premises, such as the transportation and distribution of gas by pipeline or the transmission of electricity, are widely recognised as natural monopolies.

Key elements of the regulatory regime which may differ significantly across countries include:

- ***Regulatory responsibility:*** In most cases, government moves to promote competition in the gas sector are supported by a specialist agency or authority. Usually, the authority enjoys a degree of independence from short-term political interference. The authorities' objectives and *modus operandi* are laid down in legislation. Responsibility may be vested in an individual, as in Britain, or in a commission made up of a small number of individuals: five in the United States and Mexico, and three in Italy. New Zealand, which is introducing a negotiated third-party access regime, has no sector-specific authority: it relies on the Commerce Commission to investigate allegations of anti-competitive behaviour under general competition law.

- ***Unbundling requirements:*** Unbundling is the separation of the accounting and management of a gas company's pipeline transportation and storage activities from its gas trading business. Unbundling may also involve complete separation of ownership. Separate accounts are made available to the regulator, if one exists, and, in some cases, to the general public. Unbundling ensures that costs are correctly allocated to transportation and, if relevant, to storage. This provides a basis for establishing use-of-system charges, both for third parties and the gas companies' own trading/supply business. In the United States, pipeline companies were required in the early 1990s to restructure their supply businesses into separate affiliates. Although not required to do so by the UK Government, British Gas decided to demerge its pipeline and supply businesses in 1997 (into BG and Centrica).

- ***Controls on price and rate of return:*** Most countries maintain some form of explicit price controls, either on bundled gas supply or on unbundled transportation and storage services. These controls are justified by the potential for a natural monopoly pipeline company to earn substantial economic rent and the lack of incentives for the monopolistic enterprise to operate efficiently. Such controls may be based explicitly on a calculation by the regulator or other government authority of an appropriate rate of return for the pipeline company. Where competition has been established in gas supply, price controls only apply to the transportation business. Controls on bundled gas-supply prices may be retained provisionally for the dominant supplier until competition has become well established, as in the British residential sector. Some countries, such as Germany, do not explicitly or directly control or regulate prices on the grounds that interfuel competition effectively limits the prices that gas companies can charge throughout the gas chain. Nonetheless, the Federal Cartel Office in Germany recently negotiated reductions in distribution company tariffs which were deemed to be significantly above the national average. The Cartel Office resorted to court action and the threat of legal proceedings under German competition law. In New Zealand, there are no explicit ceilings on price or rate of return, but the Government may impose price controls on gas companies found to be abusing dominant market position.

- ***Third-party access regime:*** There are two principal types of access regime: negotiated and regulated. Negotiated access characterises a regulatory approach which places the onus on the industry to regulate itself. The government may nonetheless play a role in ensuring that negotiated access is effective. It may require the industry to prepare a formal code, setting out essential commercial terms and conditions, including grounds for refusing access and an arbitration mechanism in the event of dispute. This may be backed up with unbundling and information-disclosure requirements. Regulated access occurs when the regulator imposes more explicit controls on how pipeline companies handle requests for access to the network, and sets operational and financial conditions and charge for use of the system. The regimes in North America and Britain are best characterised as regulated. Some European countries, including Germany and France, are expected to opt for negotiated access in implementing the EU gas directive.

## TRANSITION TO A COMPETITIVE MARKET

The introduction of mandatory third-party access, whether negotiated or regulated, may not necessarily lead to more competition in practice. This is particularly true where producers or external gas suppliers are reluctant to sell directly to end users for fear of driving down wellhead or border prices. Governments or regulators may then decide to intervene actively to "kick-start" or speed up the emergence of competition by tilting the market in favour of new entrants and against the incumbent monopoly supplier. Pro-competition measures include constraints on the pricing and marketing activities of the incumbent monopoly supplier and mandatory restructuring. In Britain, Ofgas obtained undertakings from British Gas to release to competing suppliers some of the beach gas supplies that it had previously obtained under long-term contracts, and to contract for no more than 90% of new beach supplies. British Gas was also obliged for several years to publish uniform national tariffs for the contestable market to allow its competitors to "cherry-pick" the most profitable customers. Thus, the transition to a competitive market may initially involve a more heavy-handed regulatory regime.

The introduction of third-party access may entail significant transition costs. Restructuring of the gas industry in North America and Britain, combined with the emergence of surplus production and transportation capacity, led to serious financial difficulties. The pipeline companies were stuck with take-or-pay commitments and contract prices above market levels. In North America, some of these costs were recovered through a surcharge on pipeline tariffs over a number of years. In Britain, Centrica (which inherited British Gas's long-term contracts) has renegotiated terms on 46.5 billion therms of its highest-priced gas contracts, paying its suppliers $1.2 to $1.3 billion in cash and assets in compensation. No mechanism for directly recovering these costs has been put in place. In Europe, the recently agreed EU gas directive explicitly limits the degree of market opening required if granting access to third parties would cause gas pipeline companies to incur serious financial difficulties associated with their take-or-pay commitments.

# 3

# CONTRACTING AND PRICING MECHANISMS IN A COMPETITIVE MARKET

The emergence of gas-to-gas competition based on the introduction of third-party access engenders fundamental changes in the gas market. In North America and Britain, this process has involved a diversification of the range of services available to wholesale and retail buyers; a huge increase in the number and complexity of transactions, with all players investing heavily in sophisticated information and communication systems; the emergence of financial risk-management instruments including futures contracts; a shift from long-term to short-term (spot and futures) contracts for transportation and related services and for the supply of gas itself; and a move towards the use of spot gas and futures prices in the price indexation formulae in mid- and long-term supply contracts.

## GAS TRADING

The unbundling of gas commodity supply from transportation and related services and the removal of price controls revolutionises the way gas is traded, including the mechanisms used to price gas in contracts. Although North American and British experiences differ in some respects (see section 5 below), the following key elements are increasingly common to both markets:

- ***Shorter-term and smaller contracts:*** There has been a pronounced shift towards shorter-term contracts, notably fixed-price spot deals of one-day to one-year duration, and a corresponding decline in the use of long-term contracts. The average size of individual contracts has diminished as buyers seek greater flexibility in balancing load on a daily and seasonal basis. Local distributors and marketers in the United States and marketers in Britain generally seek a balance between short- and mid-term supplies. Few companies now seek to contract for more than three years of supply. Power generators still contract for long-term gas supply of five to ten years or more if they are able to sign back-to-back power purchase agreements so as to lock in a margin.

- ***Decline in take-or-pay commitments:*** The move to short-term spot trading has resulted in a decline in the use of take-or-pay commitments in medium- and long-term contracts. This has been most marked in North America, where pipeline companies encountered severe financial difficulties in the mid-1980s as a result of onerous commitments to lift gas at above market prices under long-term contracts with producers. While long-term contracts with power generators usually still include take-or-pay obligations, these typically have lower thresholds than in the past.

- ***Emergence of spot and futures markets:*** Spot markets — informal markets for over-the-counter trades of fixed volumes of gas at a negotiated market price — are a central feature of the North American and British markets. Futures markets are also increasing in importance, both as risk-management instruments and a means of buying and selling physical volumes. As much as a third of the North American market and close to a fifth of the British market is supplied with physical gas traded on the spot or futures market. Total trading volumes are considerably larger, as contracts are traded many times over. Spot trading has tended to become focussed on market hubs, facilitating the coordination of short-term gas purchasing and the booking of transportation and storage services.

- ***Spot- and futures-price indexation:*** The importance of spot and futures markets in gas pricing is greater than the size of those markets would suggest because of the widespread use of movements in spot/futures gas prices to index or escalate the base price in mid- and long-term contracts. In line with the oil market, almost all such contracts in the United States are indexed on spot or futures prices. In Britain, spot or futures gas-price indexation has only recently emerged in mid- and long-term beach contracts but is expected to become more common.

# BOOKING AND PRICING TRANSPORTATION AND STORAGE SERVICES

## Contractual Arrangements

Unbundling shifts the responsibility for booking transportation capacity and storage space to intermediate and/or end-use customers. These include local distribution companies (LDCs), large end users, and aggregators, marketers and brokers in North America; licensed shippers in Britain include marketing companies (often affiliates of North Sea producers) and some large end users, such as power generators. In North America, pipeline companies are required to provide services to shippers on the basis of standard terms and conditions approved by the regulators. In Britain, use of the network, owned and operated solely by BG Transco, is governed by the Network Code, which must be approved by the regulator, Ofgas.

Some developments over recent years in contracting for transportation and storage are common to both the North American and British markets:

- ***Booking entry and exit capacity:*** As wholesale competition has developed, flexibility in delivery and receipt points for gas supplies has emerged as an important concern. In the United States, FERC's final restructuring Order 636, issued in 1992, promoted the establishment of market centres — physical pipeline hubs used as the basis for active trading of gas and providing specialised transportation and storage services. Order 636 also introduced greater flexibility in determining delivery and receipt points for unwanted primary capacity released by shippers (see below). These moves have improved shippers' ability to balance load and have reduced transactions costs. In Britain, the Network Code introduced the concept of a National Balancing Point — a notional point in Transco's system — to give shippers greater flexibility in determining delivery points and facilitate trading of gas already in the National Transmission System.

- ***Secondary trading of capacity:*** The regulatory frameworks in North America and Britain provide for secondary trading of previously booked transportation and storage capacity released by shippers, through a computerised trading system operated by the pipeline companies. In the United States, released capacity rates are capped at regulated levels, although a grey market in bundled gas services has emerged to allow holders of pipeline capacity to capture its full market value. This occurs especially at times when capacity is constrained, during the heating season. In Canada and Britain, there are no such restrictions. Interest in capacity trading has increased in North America as shippers seek to reduce costs associated with holding unused capacity. Such trading in Britain is still relatively modest.

- ***Penalties for system imbalances:*** Pipeline companies are obliged to implement a system of severe financial penalties to oblige shippers to maintain a close daily balance between gas inputs and offtakes, especially during peak demand periods. In the United States, balancing is largely market-driven. Active trading of gas, transportation and storage services at market centres, supplemented by pipeline Operational Flow Orders (which require shippers to inject or withdraw gas at short notice in emergencies), ensure system balancing. In Britain, the lack of storage and the geographical compactness of the pipeline network, which limits linepack[6], means accurate balancing on a daily and several-times-a-day basis is particularly important to ensure system safety. Increasingly active day-ahead and within-day spot gas trading is supplemented by a fairly rigid set of Network Code rules involving a flexibility mechanism and Top-Up Manager, both run by Transco, which can result in punitive charges for shippers found to be out of balance on peak days.

Until recently, a significant difference between North America and Britain concerned the length of contracts for transportation and storage capacity. In Britain, the Network Code provides for annual booking of pipeline capacity. Storage is booked through annual tenders for different types of storage. Capacity in North America has traditionally been reserved under very long term contracts, often for 20 years of more. This appears to be changing with increasing pressure from shippers (mainly LDCs) to reduce the length of contracts to five years or less in response to greater volume and price risk as competition is extended to the retail sector.

## Tariff Structure

While trading and pricing of gas as a commodity have been largely deregulated, tariffs for transportation and storage remain tightly regulated in both North America and Britain:

6. The storage of gas within the transmission system by increasing compression.

- In North America, pipeline companies must seek approval from the regulatory authority (FERC in the United States; the NEB in Canada) for proposed rates. These proposals must be based on estimated annual operating costs plus a reasonable return on investment (cost-of-service). Rates are approved or modified on a case-by-case basis. In most cases, pipeline rates are required to be set using a straight-fixed variable methodology, whereby charges have to be broken down into a fixed capacity (or reservation) charge and a commodity charge (according to usage). Fixed costs must be allocated to capacity charges. As a result, 90% to 95% of pipeline revenue comes from capacity charges. FERC is considering allowing pipeline companies to negotiate rates where sufficient pipeline-to-pipeline competition exists. NEB is also considering alternatives to traditional cost-of-service regulations to provide incentives for pipeline companies to reduce costs and enhance the quality of service. Some pipeline companies have already agreed to mechanisms whereby they absorb some market risk in return for the opportunity to increase returns when market conditions are favourable.

- In Britain, Ofgas sets a cap on the average revenue Transco is allowed to earn, similarly based on cost and a reasonable rate of return on assets. The price cap is set for periods of five years. Annual reductions in allowable average revenue are determined by an efficiency (x) factor, currently 2%, to provide an ongoing incentive for Transco to reduce its costs to protect its earnings. Ofgas does not mandate the tariff structure, but it must approve any change proposed by Transco. Until recently, Transco allocated some fixed costs to commodity charges so that the company's revenue came more or less equally from capacity and commodity charges. The company has modified its methodology towards greater recovery of costs from capacity charges for the national transmission system: 65/35 in 1997/98, a ratio that will probably rise to 75/25 in 1998/99[7].

Storage tariffs in both markets are also regulated on a cost-of-service basis. FERC and Ofgas are reviewing the case for removing or easing caps on tariffs in certain cases. This could allow the market to play a role in determining the need for additional storage, in competition with existing storage, production flexibility and sales of interruptible pipeline capacity.

7. The UK gas year starts on 1 October.

# 4

# ECONOMIC PRINCIPLES OF GAS PRICE SETTING IN A COMPETITIVE MARKET

The nature of pricing along the gas chain differs fundamentally between a monopoly gas sector and a competitive market. To understand how competition affects pricing and, therefore prices, it is important first to understand the principles of pricing in a monopoly. Table 1 summarises and gives examples of the way prices are determined under the four main types of market structure described in section 2.

*Table 1*
**Pricing Approaches Under Different Market Structures**

| | Monopolistic | Competitive | | |
|---|---|---|---|---|
| *Market structure* | Pure monopoly | A. Pipeline-to-pipeline competition only | B. Mandatory third-party access (TPA) | |
| | | | 1. Competitive wholesale market (TPA to high-pressure system) | 2. Full retail competition (TPA to entire system) |
| *Pricing approach* | Price discrimination between customers. Netback market value, cost-plus or mix of both | Restricted form of discriminatory netback market value (depending on extent of competition) | Interfuel competition and/or gas-to-gas competition (depending on gas supply curve) | Same as for competitive wholesale market |
| *Example* | France, Belgium, Netherlands, Spain, Italy | Germany | United States, Canada | Britain |

## MONOPOLISTIC PRICING

Where a single downstream gas pipeline company is granted a monopoly over the transportation and sale of gas, the company may in principle set prices to end users on a cost-plus basis (i.e the acquisition cost of the gas plus a mark-up for non-gas costs and a return on capital) or on the basis of the market value of the gas in competition with other fuels (see box). The latter approach, by definition, involves price discrimination according to the different demand profiles of end users which determine the practical alternatives to and the cost of using other fuels. This can lead to significant profit margins, as the netback value may exceed the cost of supplying specific customer categories. Such price discrimination inevitably results in cross-subsidies between different customer categories. Often, the government or regulatory authorities limit the extent to which a gas company may apply a netback pricing approach if this results in excessive profits. As a result, monopoly gas companies in many countries apply an amalgam of cost-plus and netback market value approaches.

### The Netback Market Value Concept

The netback market value of gas to a specific customer at the beach or border is defined as follows:

| | | |
|---|---|---|
| Netback | = | Delivered price of cheapest alternative fuel to the customer (including any taxes) adjusted for any differences in efficiency or in the cost of meeting environmental standards/limits; |
| | *minus* | Cost of transporting gas from the beach or border to the customer; |
| | *minus* | Cost of storing gas to meeting the customer's seasonal or daily demand fluctuations; |
| | *minus* | Any gas taxes. |

The weighted average netback value of all customer categories is used as the basis for the negotiation of bulk prices at the beach or border.

In Europe, where monopoly is still dominant and there are a small number of large suppliers, the netback market value approach has traditionally been the basis of gas pricing throughout the gas chain[8]. Thus, the price paid by the gas company to the foreign or domestic gas producer at the border or beach is negotiated on the basis of the weighted average value of the gas in competition with other fuels adjusted to allow for transportation and storage costs from the beach or border and any taxes on gas. There are in principle three different average netback market values. These correspond to existing gas users, to new energy users (such as greenfield industrial plants) and to existing oil users with no dual-firing capability (the market value of the latter being the lowest because of the high capital cost of fuel switching). The beach/border base price that is ultimately negotiated will correspond to a level between the highest and the lowest of the three values, weighted across the different end-user customer categories. The base price is usually indexed to oil product prices (usually heating oil and/or heavy fuel oil), or simply to crude oil (on the implicit assumption that the ratio of crude to product prices will remain broadly constant). This is to ensure that effective prices over the life of the contract remain broadly in line with market values.

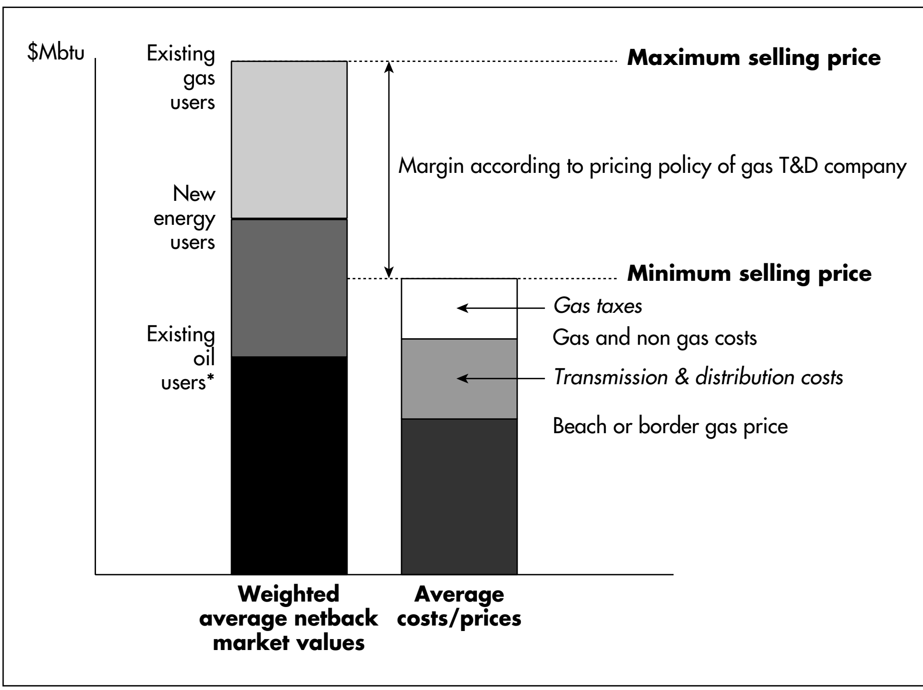
8. Such a system developed because of the imperative for pipeline companies to recover the large capital costs involved in building the pipeline infrastructure. By pricing gas through the chain in relation to competing fuels, the pipeline company can ensure that throughput and per unit revenues are maximised, and that the gross margin is protected. Risk is effectively transferred to the producer, which may be compensated by a share in any economic rent available.

The cost of production and supply to the beach or border can be considerably lower than the lowest weighted average netback market value. In Europe, for example, Norwegian and Dutch supply costs are lowest, followed by Algeria and Russia. In general, near-to-market producers are at an inherent advantage because pipeline costs are much lower. As a result, there may be a considerable economic rent to be earned between the average netback market value and the supply cost. Negotiations typically result in a sharing of the rent between the producer, any transit countries and the importer/transmission company. Once the border (base) price is set, the importer may, and usually does, pass on a proportion of its rent by setting city-gate and/or end-user prices that are below the average netback value for existing gas users. This encourages new users or even existing oil users to choose or switch to gas. Here, there is a trade-off between short term profitability and long-term market growth (see Figure 3).

*Figure 3*

**Netback Market Value and Pricing**

(Example of an Existing Monopoly Integrated Transportation and Distribution Company)




* Typically gas oil for domestic/commercial and small industrial consumers, and CCGT power generators; low- or high-sulphur heavy fuel oil for large industrial consumers and power generators (steam boilers).

Note: The gas company (for a given contracted level of beach price and non-gas costs and taxes) has the freedom to set prices between the level of its total costs plus gas taxes, and the highest netback market value (for existing gas users). If the company set prices lower than the minimum, it would not be able to cover its costs. If it set prices above the maximum, it would quickly lose market share as its customers switched away from gas to less expensive fuels. In practice, the company has to set prices no higher than the market value of new energy users to maintain its market and encourage market growth in the long term.

In practice, the downstream company's pricing policy may also be constrained by regulatory controls on pricing and rate of return. This is the case in most European countries. In France, Italy and Belgium, tariffs to the residential and commercial sectors must be set on a cost-plus basis, while tariffs to industry may be set on the basis of market value. However, since the border price of imported gas is largely set on the basis of market value, even residential tariffs are essentially market-value based. Price controls usually do not prevent substantial cross-subsidies between consumer categories; sometimes, they are designed to encourage such cross-subsidisation.

## PRICE DETERMINATION WITH PIPELINE-TO-PIPELINE COMPETITION

The entry of competing pipeline companies in a monopoly market without mandatory third-party access will have some impact on the ability of external suppliers and the incumbent monopoly gas company to impose a netback market-value pricing structure. The key is the degree of competition between suppliers and the ability of end-users and LDCs to switch transmission companies. Where there is only a limited number of competing suppliers, as in Europe, the suppliers would continue to seek a netback market-value price from the new pipeline company, limiting the company's ability to undercut the existing monopoly pipeline company. In Germany, the market entry of Wingas — a joint venture between Wintershall and the Russian gas exporting company, Gazprom — through the construction of a parallel transmission system has exerted some downward pressure on prices to large industrial end users. It has squeezed transmission margins but has not significantly undermined the netback market-value pricing structure — largely because LDCs remain tied to monopoly regional transmission companies by long-term demarcated supply contracts.

## PRICE DETERMINATION WITH COMPETITIVE THIRD-PARTY ACCESS

### Short-Run Price Determination

Gas prices in a competitive market with non-discriminatory third-party access to the pipeline network are determined by the interplay of supply and demand. At any given moment, the market price for gas, whether it be the base price in a long-term contract or the spot price (for a fixed volume supply over a short period), is determined by the marginal consumer and the marginal supplier.

The key implication of free-market pricing for gas is that, in principle, there is only one prevailing market price for the commodity at a given location. This contrasts with a monopoly, which may set the gas price for each end-use customer on a discriminatory basis. Where there are no pipeline capacity constraints, differences in market prices across regions in a truly competitive market must reflect the actual cost of moving gas between locations. Where gas flows from A to B, the price at B must be equal to that at A plus the cost of transportation: if the price at A were to move out of line with that at B, traders would arbitrage gas between the two points until prices came back into equilibrium. The cost of transportation is determined either by the regulated tariff or by the secondary market rate where secondary trading of released capacity is allowed. When pipeline capacity between two points in the network is fully utilised, the market becomes disconnected and the supply/demand balance in one market can no longer influence the price in the other. This has been the case at times over the last few years in North America, where pipeline capacity constraints between the East, West and South have led to considerable divergence in spot prices during periods of high winter demand.

Where competition through third-party access is confined to the high-pressure transmission system, as in the United States, the market sets the bulk gas price delivered to large end users supplied directly off the transmission system, as well as the price to LDCs at the city gate. The pricing policy of the LDC and the price controls imposed by regulators will determine the mark-up on the city-gate price and the structure of prices to LDC retail customers. Where competition is extended to all retail customers, as in Britain, end-user prices will reflect the bulk-market price at the wellhead, beach or border, plus the cost of transportation and distribution including any customer service costs to each end-user location.

In the short run, the demand curve for gas in a given market will be determined by the following factors:

- The importance of seasonal heating load, which in turn is largely a function of residential and small commercial short-term demand. The position of the demand curve is generally driven by the weather.

- The seasonality of demand for gas in power generation and the degree to which seasonal gas and electricity demand peaks coincide, depending on the use of electricity for heating and cooling.

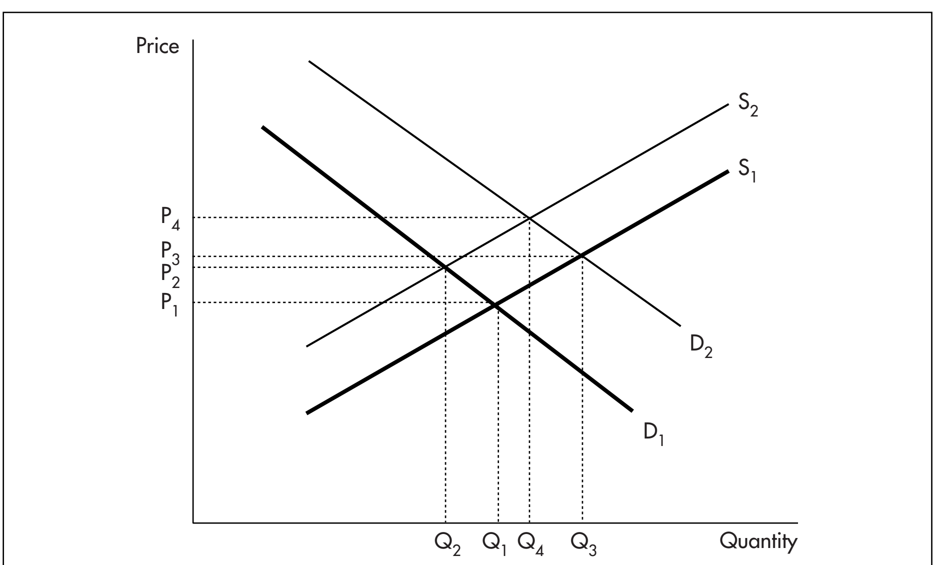
- Demand from shippers for gas to put into storage (which is in turn a function of storage capacity), prevailing storage levels, actual price levels and expectations concerning future price levels.

- Capability of end users to switch at short notice between different fuels and the prices of those competing fuels. Most end users are essentially captive in the short term. In most countries, almost all residential customers and the majority of commercial and small industrial customers do not maintain dual-firing equipment to enable rapid switching away from or to gas. Any demand response by these customers to a price change usually lags by several years. Some large customers, however, may be able to switch fuels at very short notice thanks to dual-firing or, in the case of power generators, by switching to alternative non-gas fired plant. The extent to which end users as a whole are able to switch fuels quickly helps to determine the slope of the demand curve; the price of competing fuels affects the position of the curve.

The shape of the supply curve, on the other hand, is determined by the production policy of producers (notably their willingness to shut in production and bring forward or delay maintenance programmes for economic reasons) and the willingness of holders of gas in storage to release it to the market at different price levels. Generally, the supply curve will be steep, since production becomes insensitive to price as output reaches the maximum sustainable level; at low levels of output, the curve will tend to become flat as producers shut wells rather than sell at very low prices. The willingness to sell at different prices is largely a function of expected price movements and storage levels. The position of the gas curve may change according to total short-term productive capacity. The commissioning of a new gas field or the stocking of gas through the low demand season shifts the supply curve downwards.

Figure 4 illustrates the impact on price of a sudden change in supply and demand fundamentals. A sudden decrease in supply as represented by an upward shift in the supply curve from $S_1$ to $S_2$ (resulting for example from the shutting down of a gas field) causes the gas price to rise from $P_1$ to $P_2$ but reduces the equilibrium demand for gas from $Q_1$ to $Q_2$. Given the supply curve $S_1$, a shift upwards in the gas demand curve from $D_1$ to $D_2$, caused by a sudden increase in the prices of competing fuels, causes the price to rise from $P_1$ to $P_3$. Similarly, a shift upward in both demand and supply curves (to $D_2$ and $S_2$) results in an increase in both supply (to $Q_4$) and price (to $P_4$).

*Figure 4*
**Short-Run Gas Price Determination**



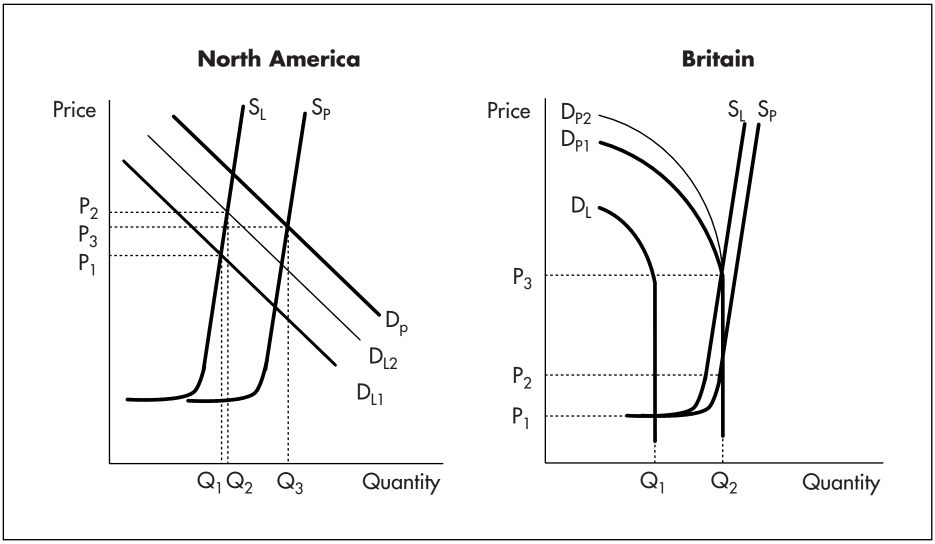
In practice, the shapes of the demand and supply curves vary considerably across countries according to short-run fuel switching capability and storage availability, which in turn depends partly on geological factors. Interfuel competition and gas-stocking behaviour both play significant roles in short-run price determination in North America because of extensive fuel-switching capability in industry and power generation and the existence of a sizable storage capacity. By contrast, interfuel competition plays virtually no role in price determination in Britain because of over-capacity (see the case studies in Part II for a detailed analysis of price setting in these markets). Figure 5 illustrates in an indicative manner this key difference:

- In North America, market conditions in the low demand season are such that a sudden shift in the demand curve from $D_{L1}$ to $D_{L2}$ caused by an increase in competing fuel prices normally results in a slight increase in the volume of gas supplied (from $Q_1$ to $Q_2$) and a proportionately larger increase in the gas price (from $P_1$ to $P_2$). In winter, the demand and supply curves shift outwards (to $D_P$ and $S_P$) as captive heating demand increases with colder weather and available supplies from storage increase. In the example shown in Figure 5, the equilibrium price is higher in the winter; in practice, lower winter demand levels due to mild weather and higher availability of gas from storage could, and sometimes does, result in lower winter prices than in the peak demand seasons.

- In Britain, the shape and interaction of the demand and supply curves are at present somewhat different. In the summer, deliverability is well in excess of maximum potential demand, so that the demand curve ($D_L$) effectively cuts the supply curve ($S_L$) at a price ($P_1$) below which fuel switching to gas or any other increase in use is possible. At that price, supply is more or less perfectly elastic; no producer or holder of gas in storage is prepared to sell at a price lower than $P_1$. In winter, the demand curve shifts up to $D_{P1}$. The supply curve also shifts up but less than in North America, because storage withdrawal capacity is more limited. The equilibrium price and supply in the winter are higher at $P_2$ and $Q_2$. However, at that price there is still no upside demand flexibility because all dual-fired capacity is already using gas. In this illustration, a shift upwards in the demand curve from $D_{P1}$ to $D_{P2}$ caused, for example, by higher oil prices, has no impact on price or demand; the supply curve would have to fall back to summer levels ($S_L$), causing prices to rise to $P_3$, before any consumers with dual-firing would switch from gas to alternative fuels. Thus, gas-to-gas competition rather than interfuel competition determines gas prices in the summer and winter.

This simplified analysis demonstrates that fuel switching potential and storage capacity in North America tends to temper seasonal and temporal fluctuations in market prices. Excess summer production capacity and a relative lack of storage (which limits the ability of suppliers to meet sudden short-term demand surges) explain why prices fluctuate over much larger ranges in Britain.

*Figure 5*
**Indicative Short-Run Demand and Supply Curves**




Note: Low demand season is denoted by $_L$ (early and late summer in North America, summer in Britain), peak season by $_P$ (winter in both markets).

A further major difference between the two markets concerns the price responsiveness of supply. Incremental onshore production capacity in the United States can be brought onstream at two to three months-notice if drilling rigs are available, so that production may respond quickly to changes in price expectations through changes in drilling activity. In Britain, the lead times of offshore projects tend to be several years, so that installed production capacity responds to price movements with very long lags (see below).

Despite these differences, the most important factor in determining short-term price movements in both the North American and British markets is the weather, especially temperatures which have a direct and predictable impact on winter heating. In the United States, weather also influences summer cooling demand. The importance of residential and commercial heating in total load in both markets, especially Britain, contributes to short-term demand volatility and unpredictability, which has a direct and pronounced effect on spot prices.

## Long-Run Price Determination

In the long run, wellhead or border gas prices in competitive markets should converge on the long-run marginal cost of production/supply to the border for a given level of demand. This should be the case regardless of the price of competing fuels (though market dynamics are such that prices are unlikely at any given time to be equal to actual long-run marginal costs). Gas prices will be lower than long-run marginal costs if productive capacity is developed more rapidly than demand growth, thereby leading to a supply surplus. This has been the case since 1995 in Britain, resulting in the postponement of some new field developments over the past-two years. Similarly, a lack of investment in production capacity could lead to prices in excess of long-run costs, as in the United States at the end of the 1970s.

Long-run marginal production costs, including exploration, development, operation and maintenance are, in turn, dependent on four key factors:

- The resource base (indigenous or external).

- Whether gas is produced in association with oil, the revenues from which may alone cover field development costs.

- The state of and developments in technology.

- Organisational efficiency, including internal productivity and partnerships between producers.

Advances in exploration, development and production technology, particularly offshore, combined with organisational efficiencies, have tended to lower real supply costs in many producing regions, including North America and the North Sea. In the United States, average reserve additions per exploratory well rose from around 9 billion cubic feet in the mid-1980s to nearly 20 bcf by the mid-1990s[9], mainly due to deep water drilling in the Gulf of Mexico. There is thought to be remaining untapped potential for increasing field productivity in these regions, although technology and organisation-driven efficiency improvements may be offset by increasing costs associated with drilling in more remote and deeper water locations.

Demand, the other side of the price equation, depends in the long run on a number of factors, including economic growth, competing fuel prices, end-use technology and environmental constraints on energy use, which may favour or discourage gas use.

9. See IEA, *The Gas Security Study* (1995)

# 5

# APPLICABILITY OF NORTH AMERICAN AND BRITISH EXPERIENCES TO OTHER COUNTRIES

There has been considerable discussion about the applicability of the competitive gas market experiences of North America and Britain to other countries. It is important to recognise the strong similarities and important differences between those two markets, which must be taken into account when considering their broader applicability.

## SIMILARITIES AND DIFFERENCES BETWEEN NORTH AMERICAN AND BRITISH EXPERIENCES

In many respects, the British market has followed a similar pattern of development to US and Canadian markets, in part because of the similarity of key aspects of the infrastructure and the regulatory approach. Key similarities include:

- ***Maturity of the network:*** Both industries may be considered to be mature. The US industry grew rapidly in the 1950s, with the establishment of a continent-wide pipeline system with multiple links and interconnections. The core of the Canadian system was largely built in the 1960s, based on gas production in the Western provinces and a trans-continent pipeline link to markets in the East. The national transmission system in Britain was developed in the 1960s with the initial exploitation of Southern Basin gas fields to link the previously unconnected local town gas distribution networks, although storage still remains undeveloped. In all three countries, the bulk of the investment in the transmission system had been amortised by the 1980s.

- ***Self-sufficiency:*** The North American and British markets are self-sufficient in gas supplies on a net basis, though some international trade does take place. The United States currently trades with Mexico, exporting on a net basis, and exports to Japan, while the United Kingdom exports to the Continent and imports from Norway.

- ***Timing of restructuring:*** Final steps to restructure the bulk market were taken at a time of surplus gas supply, facilitating the development of active spot markets and direct marketing by producers. In the United States, a gas bubble began to emerge in the early 1980s after initial moves to decontrol wellhead prices took effect. Overcapacity in Western Canada added to the bubble. In Britain, the emergence of surplus gas availability in 1994/95 (exacerbated by British Gas's policy of relying on production swing to balance seasonal load) coincided with the decision to extend retail competition to small consumers.

- ***Development of spot and futures markets:*** In North America, spot and futures markets now dominate trading and pricing of gas. The British market appears to be proceeding in a similar manner, although long-term contracts signed before liberalisation took hold still account for the bulk of gas sold at the beach — as was the case in North America in the mid-1980s.

- ***The demise of take-or-pay contracts:*** Both countries experienced difficulties in unravelling take-or-pay commitments, due to the rigidity of pricing terms which caused prices under long-term contracts to move out of line with market prices. The problem was resolved in the 1980s in North America, partly through regulatory intervention. Recent renegotiations between gas producers and Centrica (the former marketing arm of the monopoly gas company, British Gas) have significantly reduced the take-or-pay problem, but any further fall in spot prices would again pose financial difficulties for the company. In neither market has the demise of long term take-or-pay commitments undermined the development of new gas reserves.

- ***Rate-of-return regulation of the transporters:*** In all three countries, the pipeline companies' tariffs are tightly regulated on a rate-of-return basis.

In spite of these similarities, there are a number of important differences:

- ***Industry structure:*** The North American industry is characterised by a multitude of transmission pipeline companies and LDCs. In Britain, there is only one national transmission company, which also owns and operates all the regional and local distribution networks. This has a profound impact on the regulation of pipeline tariffs and the management of the transition to a competitive market.

- ***Regulatory responsibility:*** In North America, regulatory responsibility is shared between the Federal authorities (FERC/NEB) and state or provincial regulatory commissions. In Britain, Ofgas is the sole regulatory authority, although the Government plans to merge Ofgas with the electricity regulatory body, Offer.

- ***Gas production:*** A key difference concerns the nature of upstream gas developments. In the United States and Canada, the bulk of gas production is from onshore fields. In many cases, new producing wells can be brought onstream at very short notice — typically two to three months. Almost all British gas production is from large offshore fields. Development projects are much larger in scale and involve much longer time lags. British supply, therefore, tends to respond much less quickly to short-term price movements. Some North Sea producers have also shown reluctance to move away from long-term contracts with oil price indexation.

- ***Seasonality of demand:*** A key feature of North American gas demand is a double seasonal peak in winter and summer. High summer power generation load helps to counteract the seasonal winter peak, raising the overall annual load factor to over 65%. British demand seasonality is more pronounced because there is no counter-seasonal load peak in the summer: power station load tends to be highest in the winter, although the load factor is very high since most gas-fired stations run as baseload plant. The average overall UK load factor at around 45% is lower than in North America.

- ***Short-term price elasticity of demand:*** At present, the short-term price elasticity of demand in the North American market is significantly greater than in the British market (see previous section). There is a considerable amount of short-term fuel switching in the United States, notably between oil and gas according to relative prices: in general, there is a tendency for industry with dual-firing and power generators to switch from gas to oil in the winter, particularly in the Northeast and Middle Atlantic. In Britain, most dual-fired capacity in power generation and industry is already fuelled with gas, but, because of a supply bubble, gas prices since 1995 have been too low to encourage any short-term switching to oil products.

- ***Storage:*** In North America, storage plays a major role alongside fuel switching in dealing with seasonality of load. Production swing no longer contributes to any significant extent. This contrasts starkly with the British market, where there is comparatively little storage and seasonal load matching is achieved mainly through swing and, to a lesser though increasing degree, supply interruptibility. Before restructuring, British Gas sought to balance seasonal load by imposing large swing requirements on North Sea producers in long-term beach contracts. The geology in the United Kingdom is generally less favourable than in North America for the development of underground storage.

## RELEVANCE OF NORTH AMERICAN AND BRITISH EXPERIENCES TO CONTINENTAL EUROPE

Any assessment of the relevance of North American and British experience with competitive gas pricing for other countries and regional markets is bound to be an imprecise and judgemental exercise. It is nonetheless possible to identify key principles of competitive gas pricing and particular aspects of how competitive markets are operating that would be likely to apply to other gas markets embarking on liberalisation. For the purposes of this discussion, we focus on continental Europe, where a degree of competition based on third-party access is to be introduced across the European Union following the adoption in December 1997 by the European Council of Ministers of a gas directive (see box) and some initiatives at the national level, notably in the Netherlands and Spain. Some of the general conclusions may be valid for other parts of the world launching structural reforms.

## EU Gas Directive

The EU gas directive aims to create a competitive market in natural gas through common rules for transmission, distribution, supply and storage. Central to this aim is the requirement to open the transmission network and storage facilities to third-party access, so that eligible customers can buy gas directly from producers if they so wish. The directive establishes minimum degrees of market opening. The initial market opening covers all power generators and all other consumers of more than 25 million cubic metres/year and a minimum of 20% of each national market. The market opening rises to 15 mcm/year and 28% of the market after five years of the directive's taking effect in 2000; and to 5 mcm/year and 33% after ten years. The directive also allows new entrants to build pipelines. Other key elements of the directive include:

- ***Access to networks:*** The directive provides for Member states to choose between negotiated and regulated access to networks. Under a negotiated-access regime, eligible customers can negotiate access with the operator of the network. Member states must require gas utilities to publish their main commercial conditions for use of their system. Regulated third-party access implies a right of access on the basis of published tariffs for use of the system, guaranteeing access on predictable terms.

- ***Unbundling:*** The directive requires that integrated gas utilities keep separate internal accounts for their transmission, distribution, storage and, where appropriate, non-gas activities. In the case of regulated access and where access to the network is based a single charge for transmission and distribution, accounts for these two activities may be combined. The authorities would have access to the accounts of the natural gas utilities.

- ***Take-or-pay derogations:*** A gas utility is entitled to apply to a Member state for a derogation from the network access requirements, if it considers that it would encounter serious economic or financial difficulties because of its take-or-pay commitments in one or more gas purchase contracts. Applications are to be presented to the Member state on a case-by-case basis, either before or after refusal of access. The Commission may request that the Member state amend or withdraw a decision to grant a derogation.

- ***Derogations for emergent markets:*** Member states which can demonstrate that the implementation of the directive would result in substantial problems for the development of the gas market in an emergent region can apply for a derogation from the requirements for eligibility and licensing for construction of new lines. Such a derogation, which also requires Commission approval, may only be granted for a given area for the first ten years after the first supply to that area.

- ***Public service obligations:*** Member states are allowed to impose on gas utilities, in the general economic interest, public service obligations which may relate to security of supply, regularity, quality and price of supplies and to environmental protection.

There are important differences between the North American and British markets and the continental European gas sector, which have important implications for the way competition and pricing could develop in Europe:

- ***Dependence on external supplies:*** OECD Europe relies on imports from non-OECD countries, mainly Russia and Algeria, for around 32% of its gas supplies. This raises concerns about supply security, although no major disruption of a political or technical nature has ever been experienced[10].

- ***Number of suppliers:*** There are only a small number of individual producers supplying the European market. Four main suppliers are controlled either by a single company (Gazprom for Russia, Sonatrach for Algeria), a dominant company (Gasunie in the Netherlands) or a centralised gas marketing organisation (GFU for Norway). Gazprom alone accounts for 23% of the total supply of gas to Western Europe. Concerns have been expressed about the market dominance of the main suppliers, Gazprom in particular, and the ability of the producers and transit countries to extract higher rent from the gas-value chain with the fragmentation of gas purchasers under competition. It is feared that, should these suppliers create a collusive oligopoly, any reduction in downstream marketing margins due to competition could be passed on to the producers in the form of higher border prices, leaving prices to consumers no lower and importing countries economically worse off. Such arguments rest on the ability and willingness of producers to cartelise gas supply. This would require both an agreement among producers to limit supply to the highest-value market segments (captive end users and interruptible consumers where heating oil is the competing fuel); and the absence of new external suppliers, such as UK North Sea producers or LNG suppliers. Neither pre-condition appears realistic at present. Moreover, EU competition rules, which also apply to non-EU companies operating on EU markets, would restrict such anti-competitive behaviour. The fragmentation of gas purchasing in Europe may in any case lead to a loosening of the current monopolistic marketing arrangements in supplier countries.

- ***Scale of investment in incremental supplies:*** Most new supply projects involve very large investments in production facilities and pipelines. Development of the Troll field, for example, involved total initial investment of more than US$15 billion; development costs for the Russian Yamal project are put at around $35 to $50 billion. There are few small-scale incremental projects. This explains why the European gas industry has been constructed on the basis of very long-term contracts (often 25 to 30 years) with heavy take-or-pay commitments. Certainly, initial large projects would not have obtained financing without this contractual backing, while the monopoly market structure ensured that downstream gas companies were willing and able to enter into such contractual commitments. At issue now is whether new large projects, such as Yamal in Siberia, can proceed at current price levels on an alternative contractual basis.

10. See IEA, *The Gas Security Study* (1995).

- ***Maturity of the industry:*** Parts of the European industry, notably in Spain, Portugal, Denmark, Greece and some regions in Italy and France, are relatively immature. Even the more mature markets in Northern Europe are immature compared with North America. Consequently, a large part of the pipeline infrastructure is still being amortised.

- ***Geographical allocation of gas supplies:*** In North America and Britain, gas flows from producing to consuming areas have generally been determined by transportation costs. Surplus Canadian gas, for example, is exported to the nearest US markets in California and the Northeastern states. Gas flows in Europe have not always followed the same economic logic for reasons of national supply diversity and security. For example, Norwegian gas is transported to Italy and Spain and Algerian LNG goes to Belgium.

These factors, and other concerns, including public service commitments and protection of jobs in the gas companies, explain the hesitation shown so far by most European countries in introducing competition based on third-party access. They also explain the relatively limited degree of market opening provided for in the EU gas directive. The success of the directive and of moves at national level to promote competition depends on a number of key factors, including:

- ***Eligibility of LDCs and co-generators:*** The directive allows Member states to decide whether LDCs are to be designated as eligible customers. The entry of LDCs into the market as direct buyers would greatly increase the market impact, especially if they were able to reduce or cancel their existing long-term contracts with the transmission companies. The directive also allows Member states, in exceptional circumstances, to set a temporary threshold on the eligibility of small co-generators where the balance of the electricity market is threatened.

- ***The availability of surplus gas:*** The ability and willingness of producers to sell gas direct to eligible end users in parallel with existing long-term-contract sales will be decisive. Producers — notably the Norwegian marketing organisation (GFU), Gazprom and Sonatrach — will need to weigh the strategic incentive of winning market share against the impact that direct sales might have on prices, and profit margins, in new and existing contracts; most large European contracts have price-reopener clauses. Producers will also have to consider the prospects for new long-term contracts with their existing gas company customers. The greater the potential gas supply surplus in Europe, the greater the competition among the producers will be to sell direct.

- ***Negotiated versus regulated access:*** The directive provides for a choice between negotiated and regulated access. Experience in North America and Britain suggests that the latter approach, accompanied by the establishment of an independent regulatory authority, would probably put stronger pressure on pipeline companies to provide access and offer cost-reflective transportation tariffs. An effective access code, including dispute-resolution procedures and backed up by competition law, will be necessary to ensure widespread access through negotiation.

- ***Take-or-pay derogations:*** The attitude of national regulators and the European Commission to applications for derogations from third-party access requirements could be decisive.

- ***The size of margins to eligible customers:*** The larger the margins currently earned on sales to eligible customers, the greater the incentive for direct sales. Margins are thought to vary widely across Europe and within each country.

## Drivers for Change in Continental European Gas Markets

- Possible emergence of a supply surplus, with potential new supplies notably from the United Kingdom (through the Interconnector), Russia and Central Asia, Algeria, Norway, Nigeria and possibly in the longer term from the Middle East by pipeline through Turkey or by LNG.

- New power-generation buyers, competing with gas utilities to buy from gas producers.

- Potential for contractual gas swaps with utilities in Central and Eastern Europe.

- Expansion of pipeline links to and within Europe.

- Vertical and horizontal integration, involving gas transmission and distribution companies, upstream companies and other energy and utility service providers.

- Regulatory push for more competition from the European Commission and, in some cases, from national regulators — driven, in turn, by concerns about industrial competitiveness.

Given the uncertainties surrounding the extent and pace of market opening in Europe, it is hard to predict the implications of liberalisation for gas pricing and price setting. Key drivers for change are summarised in the box above. It is important to note that there are a number of factors working to maintain the status quo, including resistance from national governments and incumbent monopoly utilities. In particular, there is uncertainty over the extent to which utilities and EU Member states will resort to seeking derogations on the basis of take-or-pay commitments and the response to such moves by the Commission[11]. The extent to which some countries will want to open their markets faster than required by the directive is also uncertain, although the expectation is that the overall market opening across the European Union will exceed the minima laid down in the directive.

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11. The European Commission has stated that it intends to apply the criteria for derogations for emergent regions in a restrictive manner to prevent an "unacceptable proliferation of such derogations".

Despite these uncertainties, the following broad conclusions may be tentatively drawn:

- ***Development of spot and futures markets:*** Depending on the extent to which incremental gas supplies are made available by producers (both existing suppliers to Europe and new entrants), some short-term spot trading is likely to develop, albeit gradually. The UK-Continent Interconnector will most likely provide a platform for the establishment of an active spot market based on sales at Zeebrugge[12]. Other spot delivery locations could emerge later. The successful establishment of a formal futures market later on would depend on sufficient liquidity on spot markets. The development of short-term trading should lead to a degree of price volatility, although the larger storage capacity in continental Europe should ensure that prices are less volatile than in Britain.

- ***Long-term contracts:*** Third-party access for large end users and the emergence of spot trading will *not* signal the rapid demise of long-term contracts. For as long as third-party access is limited to large end users, downstream gas companies with protected monopoly markets will continue to negotiate long-term contracts, although their length may shorten from the current norm of 20 to 25 years to perhaps 10 years. Not all new upstream developments will require long-term contracts to achieve financing, as was demonstrated by the Interconnector. Take-or-pay commitments may eventually become less common and less onerous. The development of spot markets should progressively provide a ready outlet for any surplus contractual volumes that downstream gas companies find themselves with. Those companies should be able to avoid the severe financial difficulties that North American pipeline companies and British Gas encountered over take-or-pay commitments; they can use the price reopener clauses in most long-term contracts in Europe and the take-or-pay derogation provisions of the EU directive.

- ***Price indexation:*** Greater diversity in indexation formulae and a move away from oil as the sole or main element may emerge. Indexation formulae may increasingly be tailored to the needs of end users. Power generators will seek power price indexation particularly if they are unable to price power sales on an oil-price basis in back-to-back agreements. The inclusion of some element of spot gas price indexation will probably emerge. Price-reopener clauses in new long-term contracts may explicitly provide for a shift to spot gas price indexation once an active European spot market emerges.

- ***Daily and seasonal load balancing:*** Load balancing requirements will emerge as a critical aspect of the new liberalised European market. Seasonal and daily balancing imperatives and the establishment of severe financial penalties for shipper imbalances will lead eventually to interruptibility and storage being used and contracted for on a truly commercial basis. The Netherlands, with its large-capacity high-swing Groningen field and two large underground facilities

12. Some spot deals have already been reported.

being built by Gasunie, could develop as a key trading and physical supply hub. Other European gas companies, such as Gaz de France and Distrigaz in Belgium, may be able to extract greater value from their existing storage assets. As in North America, there will probably be greater emphasis on investment in high-deliverability storage facilities as competition develops.

- ***Convergence of gas and power markets:*** Increasingly, power generators, traders and risk-management service providers will seek to take advantage of short-term opportunities for arbitraging gas according to its value in the gas market relative to its value converted to electricity. The extent to which such opportunities arise in Europe may, however, ultimately be limited by the coincidence of peak demand for gas and electricity, although the importance of arbitraging as part of risk management strategy will probably grow as gas use in power generation and short-term markets in gas and power expand.

# 6

# LESSONS FOR POLICY MAKERS AND REGULATORS

There is clear evidence that gas market reforms have brought benefits in the form of increased efficiency in the provision of transportation and marketing services, more market-driven investment decisions, a broader range of services and lower prices to most consumers, although it is difficult to determine the role played by other factors in lowering prices. The extent to which markets have been dynamised through productivity improvements, innovation and new investment has often surprised even the advocates of a more market-oriented approach to gas policy.

There is no catch-all prescriptive model for the process of deregulation and restructuring, nor the ultimate regulatory framework once competition has been established. Policy makers and regulators need to take account of specific national circumstances, including the state of the pipeline and upstream infrastructure, the ownership structure of the industry and market trends. Nonetheless, in managing the process of change to a more competitive gas market, policy makers and regulators can learn from the experience of countries which have gone furthest in liberalising their gas sectors.

Broad lessons learnt in North America and Britain might be summarised as a need for:

- ***Explicit terms and conditions of access:*** Transparency in the non-price terms and conditions of access to the pipeline system and storage facilities is a key factor in preventing discrimination between shippers (including the pipeline company's own marketing body), encouraging access and competition, and ensuring efficient operation of the industry. North American and British experience reveals the value of giving the industry itself primary responsibility for establishing such an access code in a cooperative and consultative fashion.

- ***Effective unbundling:*** The effective separation of the management and accounting of the pipeline and storage functions from the gas supply and trading activities of gas companies is crucial to ensuring non-discriminatory third-party access and efficient regulation. Unbundling ensures that costs are correctly allocated to transportation and storage as the basis for establishing use-of-system charges, both for third parties and for the gas companies' own supply and trading business.

- ***Regulation of pipeline charges:*** In most cases, pipelines facilities are natural monopolies, and encouraging competition in the provision of these services is generally not economically efficient. Some form of rate-of-return or price regulation is, therefore, necessary to prevent pipeline companies from overcharging for the use of their systems and enjoying a monopoly rent. Some countries, such as New Zealand, have opted for a light-handed approach to pipeline regulation based on information disclosure and general competition law. They hope to avoid the cost and complexities of North American- and British-style detailed rate of return regulation based on cost-of-service. Such a light-handed approach requires a body of competition law that is both effective and enforceable. It remains to be seen whether such an approach can be effective in preventing the abuse of dominant market position and in encouraging operational efficiency.

- ***Clearly defined regulatory responsibility:*** Whatever the precise approach to regulation adopted, responsibility for it needs to be clearly defined and vested with an appropriate governmental body. Some countries have set up independent authorities with clearly defined responsibilities, powers and objectives, in order to keep the day-to-day regulation of the gas sector free from political interference. Where the Government owns the utility, it is important to avoid short-term budgetary pressures, as well as to ensure a degree of transparency and consistency in decision-making. While this approach has arguably proved successful in many cases, accountability remains a problem.

Security of supply, particularly in countries dependent on a small number of external suppliers, is often a key concern. Security is best seen in terms of risk management, that is, reducing to an acceptable level the risks and consequences of supply disruptions and shortfalls. There is evidence, particularly in North America, that competitive gas markets have enhanced short-term supply security, through the improved flexibility in responding to emergencies provided by sophisticated information and control systems and market-responsive price signals. They have strengthened long-term security through development of transmission and storage. The explicit and transparent pricing of the means of providing short-term security (interruptibility, swing and storage) in competitive markets allow end users, marketers and LDCs to determine the appropriate level of security through optimisation of their gas supply and delivery portfolios.

There is certainly a role for Government in enhancing both short- and long-term gas security, for example in facilitating international trade and investment in pipeline interconnections, determining acceptable security levels for small consumers, setting safety requirements, and providing a legal basis for dealing with emergencies.

# II

# PART

# CASE STUDIES

## A: North America

## B: Great Britain

A

# NORTH AMERICA


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# 1

# SUMMARY

- The North American gas industry has been undergoing a fundamental structural evolution for the last 20 years, in large part due to changes in the regulatory framework governing the pricing of gas and the way in which the industry operates. Restructuring in both countries began with wellhead price deregulation, followed by open access to the interstate pipeline and storage system, and the unbundling of interstate pipeline companies' gas purchasing, transportation and sales activities. Several state and provincial regulators are considering expanding open access and retail competition, now limited to large end users, to small residential and commercial consumers.

- Pipeline and storage charges remain, for the most part, regulated by the Federal Energy Regulatory Commission in the United States and the National Energy Board in Canada on a traditional cost-of-service basis. Booked capacity at regulated rates can be released by shippers and traded on secondary markets. In the United States, secondary rates are officially capped at primary regulated levels, although an informal grey market in bundled services has emerged to allow holders of capacity to realise its full value during periods of high demand.

- The decontrol of gas commodity prices at the interstate level and the mandatory unbundling has led to major changes in the way gas is traded and transportation services are marketed. Short-term spot and futures trading for deliveries of up to one month now account for a significant proportion of physical gas deliveries. In these contracts, the price is fixed at the time of the deal for the whole delivery period. Although medium- and long-term contracts still account for the bulk of gas deliveries to LDCs and large end users supplied off the interstate network, prices are generally indexed to spot or futures prices.

- Weather is the primary driver behind short-term spot price movements, because of the sensitivity of residential and commercial demand for winter heating and power-generation demand for summer cooling. Storage plays a key role in balancing seasonal and short-term loads and limiting the volatility of spot price movements.

- Because of the existence of a significant amount of short-term fuel-switching capability in industry and power generation, interfuel competition plays a major role in day-to-day price setting. This demand-side flexibility limits the seasonal volatility of spot prices: prices in the Northeast and Mid-Atlantic are effectively capped at prevailing heavy-fuel-oil price levels in the winter, when oil typically replaces gas in power generation and in some industrial uses. The ability of power generators to burn coal in the south effectively sets a floor price for gas in the summer.

- At times when capacity is not constrained, effective marginal transportation costs (primary or secondary rates) determine differentials between spot prices at different locations throughout North America. Periodic bottlenecks in capacity, particularly during cold winter periods, can lead to the delinking of regional markets and a considerable divergence in regional price differentials.

# 2

# INTRODUCTION

## MARKET OVERVIEW

### United States

The United States has the largest natural gas market in the world. Gas supplies accounted for 24.4% of total primary energy in 1995, up from 22% in the mid-1980s but well below the peak of around 30% in the early 1970s. In absolute terms, the natural gas market peaked in 1974 at 22.1 trillion cubic feet (tcf) but had recovered to almost that level by 1996. The industrial sector accounts for almost half of total deliveries (see Figure A-1).

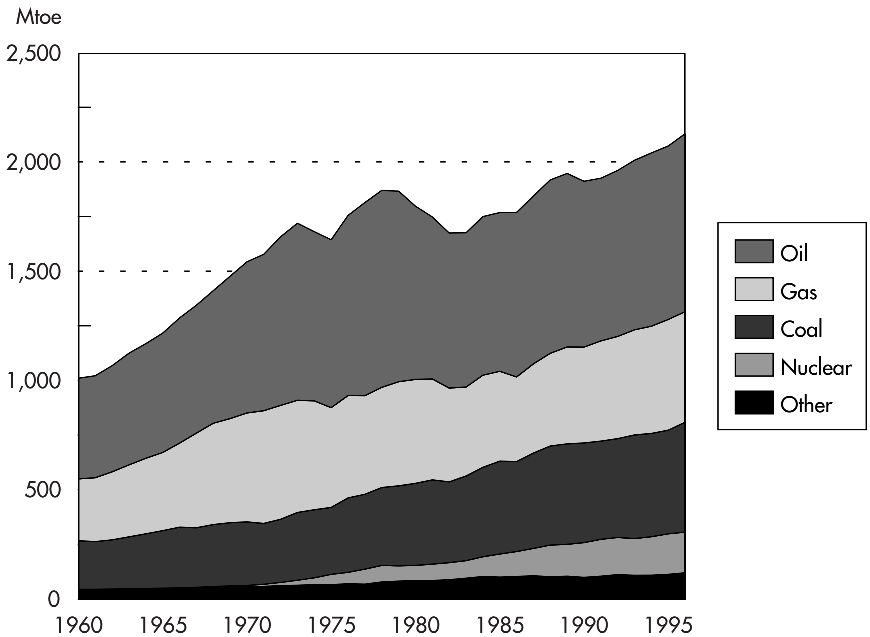
Indigenous production accounts at present for around 85% of total gas supply. Imports from Canada account for most of the rest (small amounts of gas are exported to Mexico and Japan). Production is concentrated in the southern and central states, with Texas and Louisiana between them supplying almost two-thirds of total dry gas output (see Figure A-2). Almost three quarters of gas produced in the United States comes from 304 000 gas wells, the rest being produced in association with oil.

The United States has a vast network of high-pressure interstate pipelines or trunklines that carry gas from the major supply areas — notably the Mexican Gulf (onshore and offshore), the lower Midwest, the Permian Basin on the Texas/New Mexico border, the San Juan Basin in the southwest and the Rockies — to the main areas of consumption both within the producing regions and in the Northeast, Midwest and California. There are also a number of pipelines linking the principal producing fields in the Western Canada Sedimentary Basin with US markets in California, the Midwest and the Northeast. The Northeast is the single largest consuming region, served by around 25 major pipelines from the Southwest, Midwest and Canada. The network is highly integrated, so that gas from producing states in the Gulf region can in principle move just about anywhere in the system. The transmission system comprises around 270 000 miles of pipelines. Distribution is carried out by local companies, supplied off the high-pressure network. The distribution system is made up of around a million miles of pipe. Figure A-3 illustrates the main flows of gas from producing to consuming regions within the United States.

There is considerable storage capacity in the United States. At the beginning of 1997, 410 sites were in operation with total working gas capacity of 3. 76 tcf and maximum daily delivery capacity of 74.6 bcf — equivalent to around 110% of average annual consumption (see Table A-1). The overwhelming majority of storage facilities are depleted gas/oil reservoirs (343), followed by aquifers (40) and salt caverns (27). There is a small amount of LNG storage capacity at four terminals (at Everett, Massachusetts; Cove Point, Maryland; Elba Island, Georgia; and Lake Charles, Louisiana). The location of the storage sites by type is shown in Figure A-4. Salt caverns, with relatively high deliverability and short cycling periods, are located mainly in the South, East Central and Northeast regions.

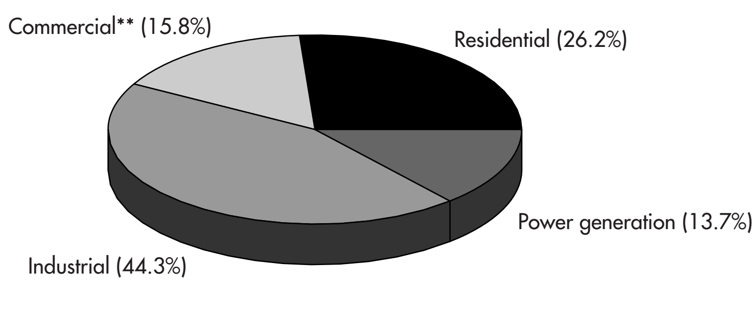
*Figure A-1*
**US Natural Gas Supply and Demand**

**Total Primary Energy Supply by Fuel (1960-1996*)**




* Provisional estimates

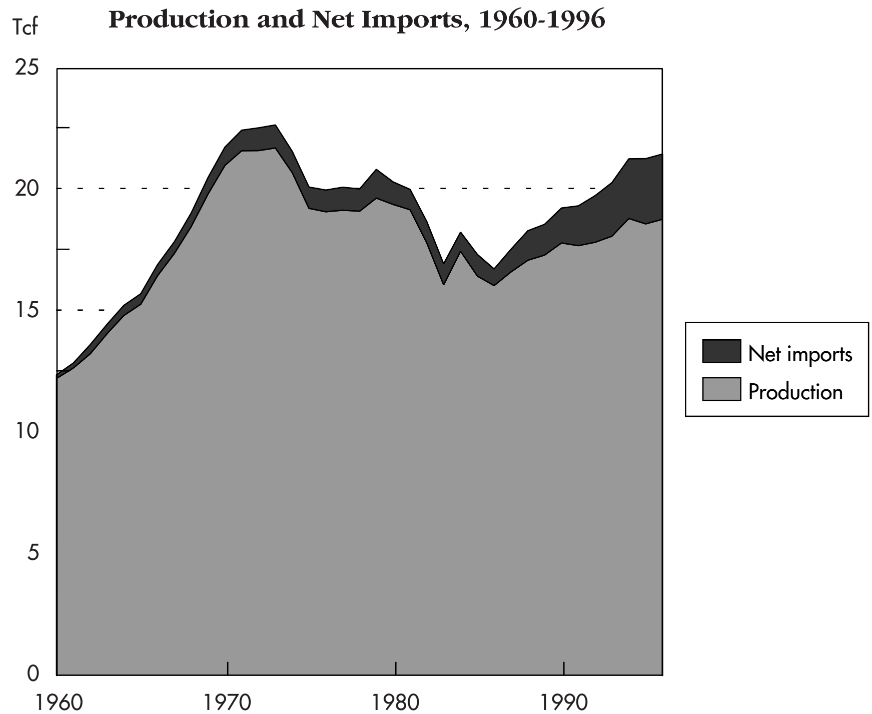
**Gas Delivered to Consumers, 1996***

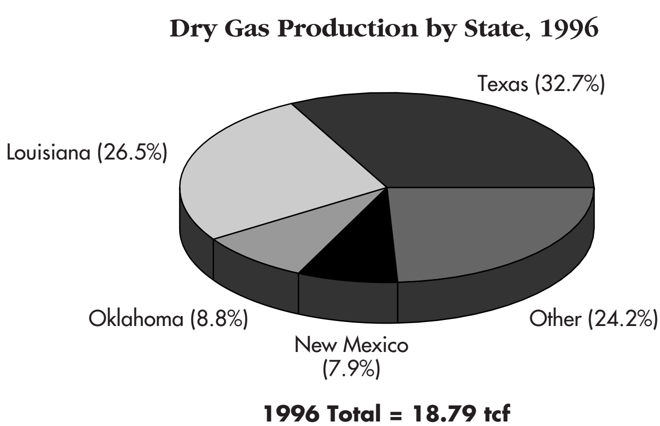



*  Not including pipeline and energy sector own use
** Includes vehicle fuel

Source: IEA, *Energy Balances of IEA Countries* (OECD, 1997); EIA, *Natural Gas Annual 1996* (DOE, 1997)

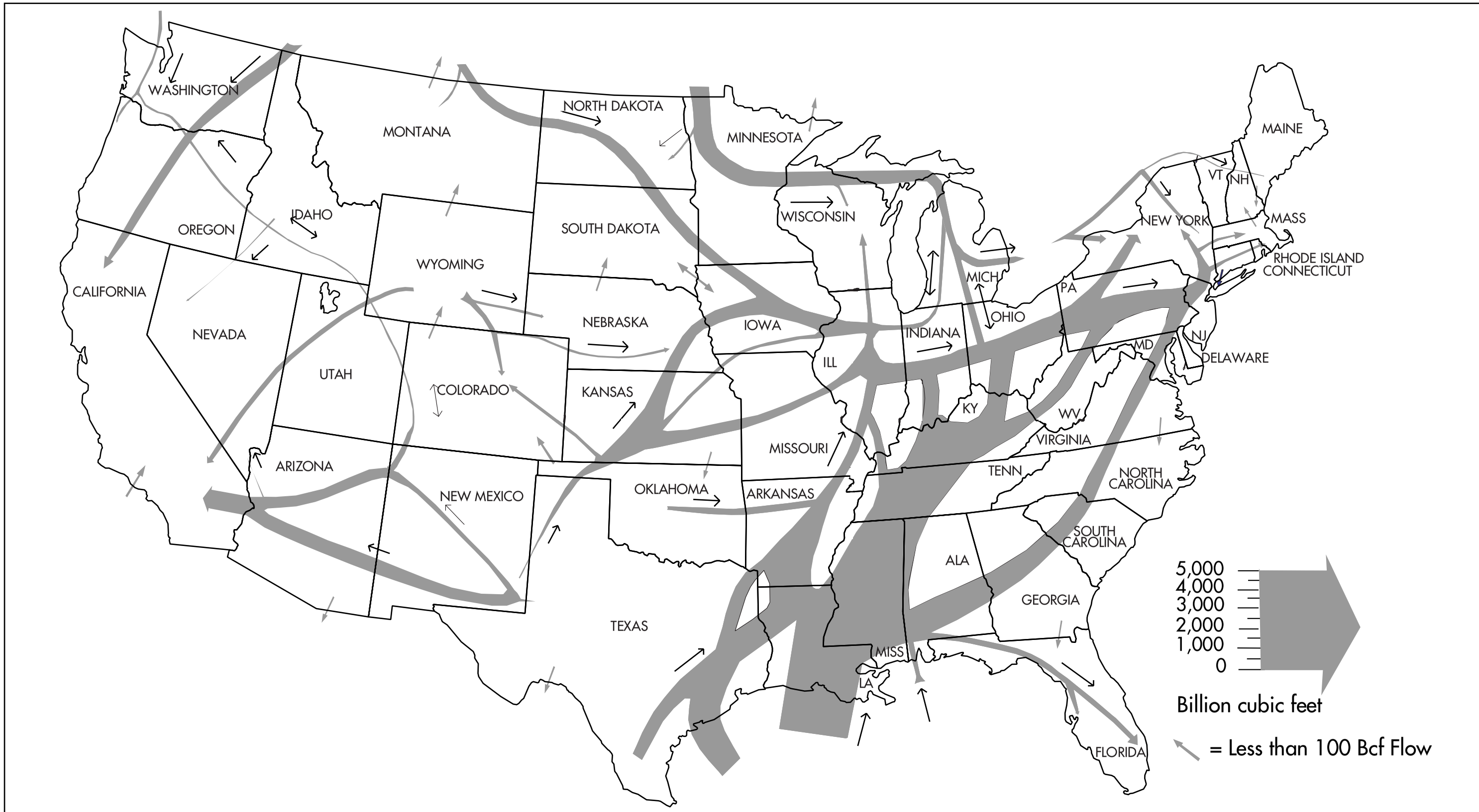
*Figure A-2*
**US Natural Gas Supply**




Source: EIA, *Natural Gas Annual 1996* (DOE, 1997); EIA, *Annual Energy Review 1996* (DOE, 1997)

*Figure A-3*
**US Interstate Natural Gas Flows, 1996**



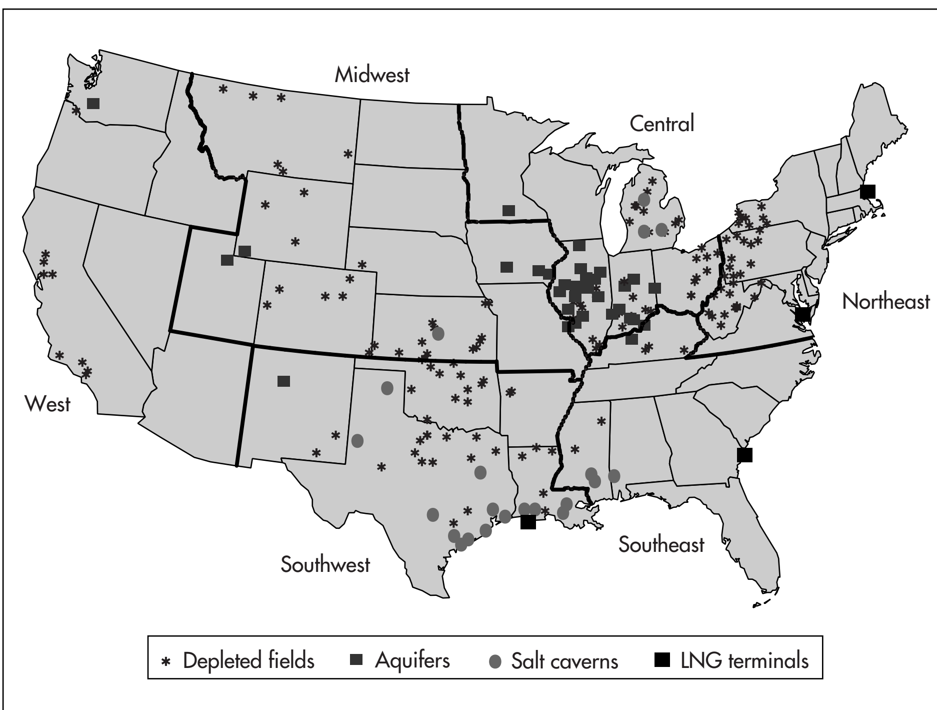

Source: EIA, *Natural Gas Annual 1996* (DOE, 1997)

*Table A-1*
**Summary of US Gas Storage, at January 1997**

| | Sites | | Working Gas Capacity | | Daily Deliverability | |
|---|---|---|---|---|---|---|
| Region | Number | % of US Total | Bcf | % of US Total | Mcf/d | % of US Total |
| Northeast | 121 | 30% | 670 | 18% | 11 701 | 16% |
| Southeast | 33 | 8% | 173 | 5% | 5 220 | 7% |
| Midwest | 128 | 31% | 1 133 | 30% | 24 000 | 32% |
| Central | 49 | 12% | 562 | 15% | 6 037 | 8% |
| Southwest | 67 | 16% | 981 | 26% | 20 500 | 27% |
| Western | 12 | 3% | 246 | 7% | 7 120 | 10% |
| **US Total** | **410** | **100%** | **3 765** | **100%** | **74 579** | **100%** |

Source: EIA, *Natural Gas Monthly, September 1997* (DOE, 1997)

*Figure A-4*
**Locations of Natural Gas Storage Facilities in the United States**




Source: EIA, *Natural Gas Annual 1996* (DOE, 1997)

# Canada

Thanks to substantial reserves in its western provinces, natural gas meets around 29% of Canada's energy needs — well above the average for IEA countries. Final sales of gas (excluding pipeline fuel and energy sector use) amounted to 61 bcm in 1995. Industrial sales made up 45% of total domestic gas sales, while residential sales accounted for 27%, commercial sales for 20% and power generation 9%. Domestic sales have increased steadily in recent years, mainly due to increased gas availability and residential/commercial demand in the Northeast (see Figure A-5).

Canada's natural gas resources are immense but are spread over a very large number of relatively small pools: as of 1992, reserves had been identified in 26 900 different pools. The Western Canadian Sedimentary Basin (WCSB), centred on Alberta, accounts for around 70% of discovered resources and around 99% of current production.

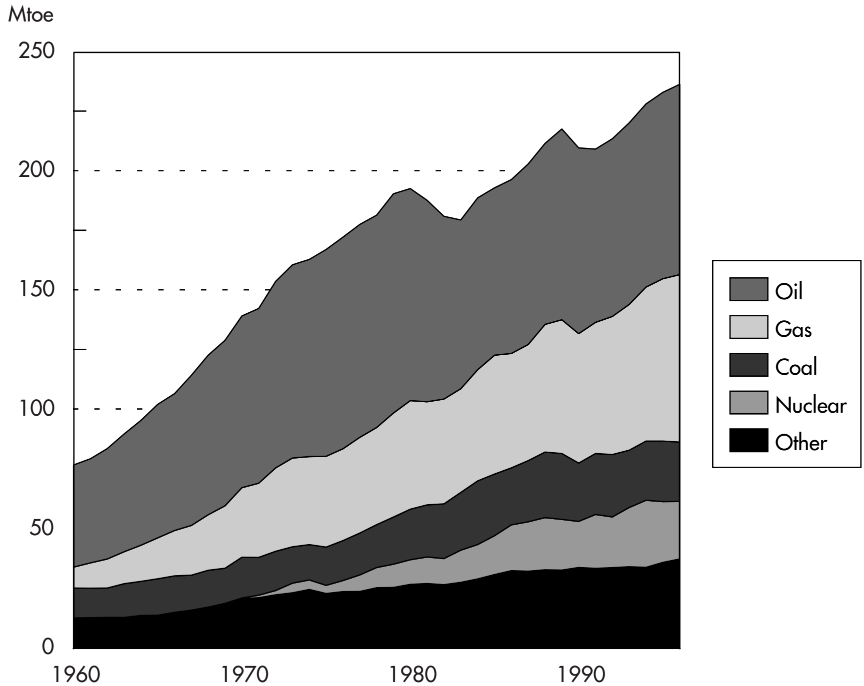
In 1995, Canada exported 78 bcm of natural gas to the United States (net of a small volume of imports), currently its sole export market. This volume represents 49% of total Canadian production. Of the total export volume, 40% was delivered to the US Midwest, 23% to the Northeast, 22% to California and 15% to the Pacific Northwest. Canada's natural gas exports to both California and the US Pacific Northwest increased by almost 5% in 1995 and by a further estimated 6% in 1996 as a result of additional pipeline capacity.

Although there is considerable consumption of natural gas in the producing provinces, the Canadian gas industry is still characterised by "production in the west, consumption in the east". This is clearly reflected in the gas infrastructure: all the production fields, gathering pipelines and processing plants are located in the west; the single West-East transmission pipeline (TCPL) carries gas across the country to regional and local distribution pipelines in the East. The inherent vulnerability to supply disruption in this system is mitigated by substantial upstream storage capacity in Western Canada (to mitigate production disruptions) and downstream storage (to handle seasonality of demand) in eastern Canada. The network comprises 246 000 kilometres of gas pipelines stretching from Vancouver Island to Québec City. The export points for gas to the United States are spread out along the Canadian-US border (see Figure A-6). Currently, there are 16 pipeline interconnections between Canada and the United States with a total annual maximum capacity of 85.8 bcm. During 1993 the average load factor for all the pipelines to the United States was 91%. Flows in these pipelines are not reversible.

Total storage capacity in Canada is 12.4 bcm (0.44 tcf); the maximum send-out rate is 0.72 bcm per day (25.4 bcf/d). Downstream storage capacity (both working gas and withdrawal) is slightly higher than upstream storage. Since deregulation in the mid-1980s, actual annual output from storage has more than tripled.

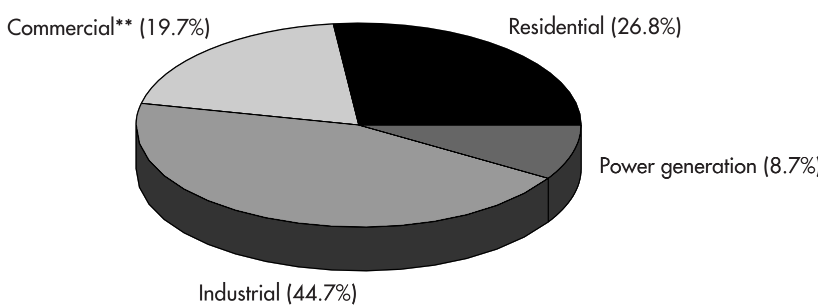
*Figure A-5*
**Canadian Natural Gas Supply and Demand**

**Total Primary Energy Supply by Fuel (1960-1996*)**




* Provisional estimates

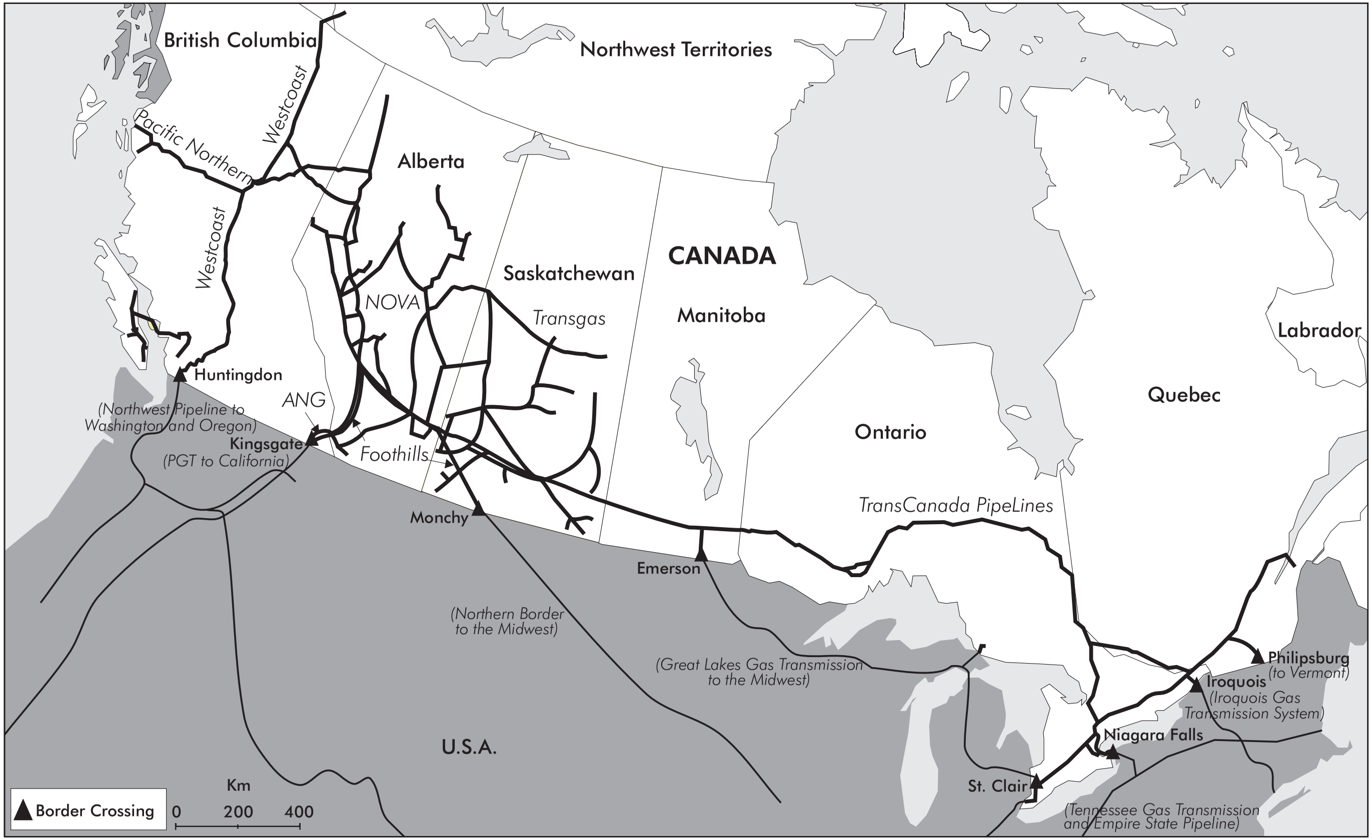
**Gas Delivered to Consumers, 1995***




* Not including pipeline and energy sector own use
** Including vehicle fuel

Source: IEA, *Energy Balances of IEA Countries* (OECD, 1997)

*Figure A-6*
**Major Canadian Natural Gas Pipelines**



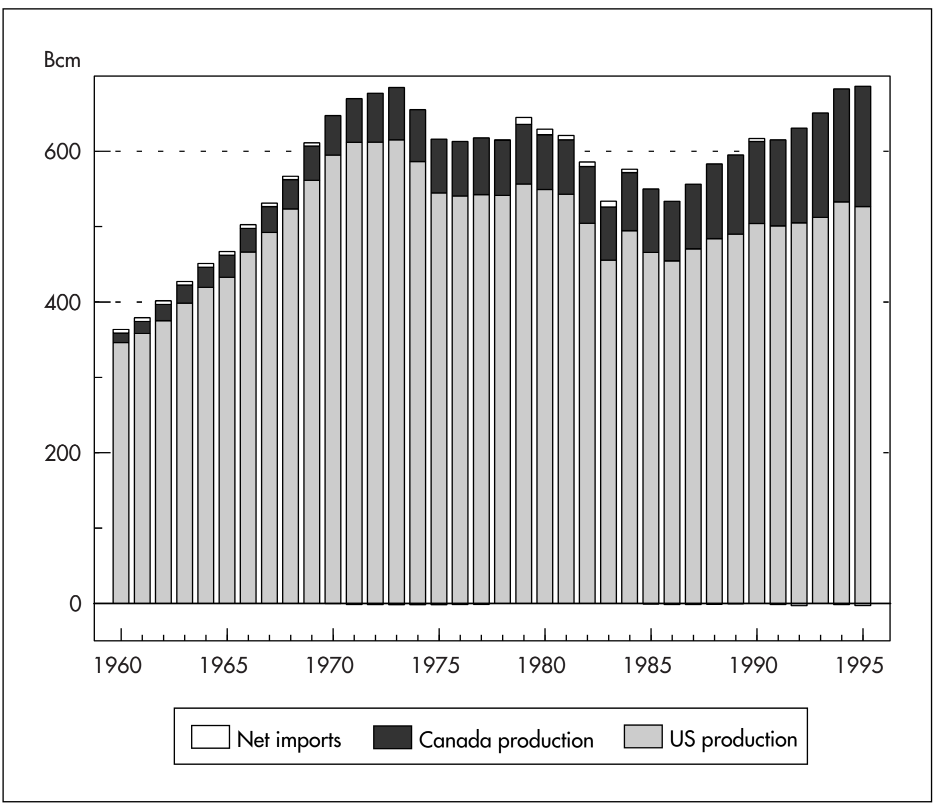

Source: Natural Resources Canada

## The Combined North American Gas Market

The significant pipeline links and the substantial flows of gas from Canada to the United States mean that the countries' systems may be considered a single network, though the degree of connection among parts of the network varies considerably. The Western United States is, in fact, more closely integrated with Canada than it is with the Eastern US market. The degree of regional interconnection and the implications for gas price setting are considered in section 5.

The combined North American market (Unites States and Canada) amounted to 24.4 tcf of primary energy supply in 1995 — equivalent to just around 60% of total OECD consumption. The United States accounts for 88% of total North American primary gas demand and 77% of total production. Net imports from outside the region made up less than 0.1% of total North American supply in 1995 (see Figure A-7).

*Figure A-7*
**North American* Primary Gas Supply**




* United States and Canada

Sources: IEA, *Natural Gas Information 1996* (1997); EIA, *Natural Gas Annual* (various issues).

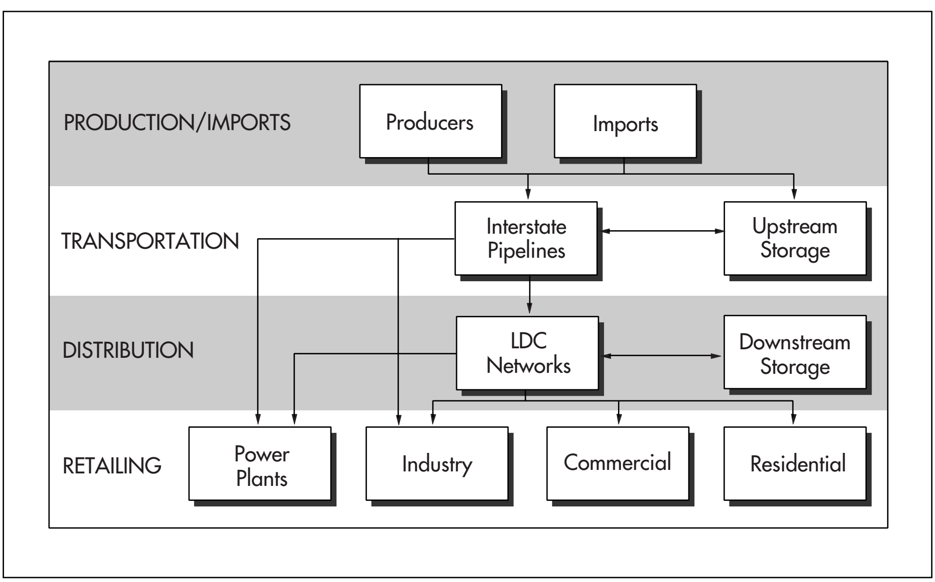
## United States

The US gas industry is very diversified compared to those of other IEA countries, with no single dominant company. There is a low level of vertical integration compared with other energy industries, with different ownership structures and players at each level of the gas chain (see Figure A-8).

There are somewhere in the region of 23 000 gas producers, ranging from small "mom and pop" operations to major international oil companies. The seven largest producers — Amoco, Exxon, Mobil, Chevron, Shell, Arco and Texaco — account for around 30% of total US output.

There are over 40 separate interstate pipeline companies, though affiliate companies number more than 200. The largest, in terms of firm contracted demand, are Columbia Gas Transmission Corporation (in the Northeast), the Natural Gas Pipeline Company of America (Midwest), Tennessee Gas Pipeline Company and Transcontinental Gas Pipeline Corporation (both Northeast)[13]. Many states have more than one pipeline supplier. Pennsylvania, for example, is served by seven pipeline companies. Most underground storage facilities are owned and operated by pipeline companies.

*Figure A-8*
**Physical Gas Flows in US Industry**




13. See EIA, *Natural Gas 1996: Issues and Trends* (DOE, 1996), Appendix D.

Distribution is primarily carried out by local distribution companies (LDCs) that purchase gas supplies at the city gate. For historical and regulatory reasons, some LDCs operate high-pressure intrastate pipelines, underground storage and peak shaving facilities (to meet short periods of highest demand), though most storage is in the hands of interstate pipeline companies. Many large industrial customers and most power plants are supplied directly off the high-pressure system, bypassing the LDC system. Increasingly, other industrial and commercial customers supplied off an LDC grid are able to contract directly with gas marketers or producers; they pay distribution charges to the LDC as well as transportation fees to the pipeline companies.

Ownership of interstate transportation and local distribution networks is diversified. All interstate pipelines and most storage operations are owned by private investor-owned companies, some of whom are partly or wholly owned by major oil and gas producers. LDCs can be either investor-owned or municipally-owned (the latter account for around 7% of all gas distributed in the United States). In general, the largest LDCs, which serve upwards of one million customers, are investor-owned utilities. The smallest are more often owned by the local municipality. Few LDCs have any production interests. There have recently been several mergers between LDCs and acquisitions of LDCs by pipeline companies or their holding companies.

The Federal Energy Regulatory Commission (FERC) is responsible for regulating access to and tariffs for using the interstate pipelines and storage facilities linked to those pipelines. State public utility commissions are responsible for regulating distribution activities.

## Canada

The Canadian gas industry consists of gas producers, processors, transporters, marketers and distributors. As in the United States, no company is fully integrated from production to distribution. There are, however, linkages between the upstream and downstream sectors. Large producers often own facilities that process raw natural gas and a few pipelines and local distribution companies have production and marketing subsidiaries.

The production sector is composed of a wide variety of companies, from large multinational oil and gas companies to small local firms and a handful of Crown-owned organisations. The smaller producers tend to sell their output through aggregators or marketers. Many larger companies directly market their supplies. While there are around 1 000 producers in Canada, the 100 largest account for more than 85% of production.

All transmission pipelines, both inter- and intra-provincial, are owned and operated by private sector companies, except the gas transmission system in Saskatchewan, TransGas, which is a Crown corporation. There are eight major transmission pipelines. The most important systems are NOVA Gas Transmission in Alberta and TransCanada Pipelines east of Alberta (see Figure A-6). These systems carry gas for both domestic and export markets. The two companies plan to merge. In addition there are several export-oriented pipelines such as Alberta Natural Gas Company and Foothills Pipelines.

Distribution is carried out by local, predominantly privately-owned utilities that have a monopoly of the pure distribution function. Customers total 4.3 million, most of them served by 18 distribution companies or their affiliates. For many years, large industrial customers and power generators have been able to buy their gas directly from producers. Recently, some provincial regulatory boards have permitted end-use consumers in the residential and commercial sector to buy gas directly from producers through aggregators, brokers or other middlemen (see next section), although the LDCs have retained their *de facto* monopoly over physical distribution. Historically, almost all storage capacity has been held by the LDCs. Over the last few years, however, this has changed: non-LDC storage now represents 43% of Canadian working gas storage.

The transmission part of the gas chain is regulated by the National Energy Board (NEB), the federal regulatory body, except for the NOVA transmission pipeline, which is regulated by the province of Alberta. Natural gas gathering and processing facilities have historically been regulated by provincial authorities, except for those owned by Westcoast Energy in British Columbia. Local distribution is regulated on a similar basis by provincial regulatory bodies.

3

# INDUSTRY RESTRUCTURING AND REGULATORY REFORM

The North American gas industry has been undergoing a fundamental structural evolution in recent years, in large part due to changes in the regulatory framework governing the pricing of gas and the way in which the industry operates. Reforms have moved at a similar pace in the United States and Canada, although some significant regulatory differences have appeared.

## UNITED STATES

### Deregulation of the Interstate Gas Business

Deregulation of the US gas industry was initiated by the 1978 Natural Gas Policy Act, which partially decontrolled wellhead prices and relaxed some restrictions on interstate pipeline transportation. This move, prompted by gas shortages in the 1970s which were blamed on wellhead price controls, coincided with rising demand. In these conditions, producers were able to bid up wellhead prices in the deregulated market and impose onerous long-term take-or-pay commitments on the interstate pipelines companies. A slump in gas demand in the early 1980s resulting from the recession and higher prices led to the emergence of surplus supply, known as the gas bubble, and downward pressure on prices. This meant that pipeline companies could neither take nor pay for the gas they had contracted to lift. The landmark FERC Order 436, issued in 1985 and implemented in 1986, was intended to help resolve the pipeline companies' financial difficulties. It paved the way for opening up access to the US gas pipeline system on a voluntary basis and increased competition in domestic markets: where a pipeline company had lost sales volume, open access allowed the company to earn additional transportation revenue to compensate. Order 500 in 1987 further addressed acute take-or-pay problems. This was followed by the Wellhead Decontrol Act of 1989 which specified the staged removal of all remaining controls on wellhead gas prices by the end of 1992.

**Key Dates in the Deregulation of the US Natural Gas Industry**

1978 Natural Gas Policy Act ends federal control over the wellhead price of «new» gas as of 1 January 1985, but keeps in place wellhead price controls for previously contracted gas.

1985 FERC Order 436 establishes a voluntary programme that encourages natural gas pipelines to become open access carriers of natural gas bought directly by users from producers. This order begins the separation of pipelines' merchant and transportation functions, and initiates reform of the natural gas industry's regulatory structure.

1989 Natural Gas Wellhead Decontrol Act lifts all remaining wellhead price controls.

1992 FERC Order 636 obliges interstate natural gas pipelines to unbundle. The goal of this order is to ensure that all natural gas suppliers compete for gas purchasers on equal footing.

1995 The first choice programmes for residential customers are implemented. By late 1997, local natural gas utilities in more than 20 states and the District of Columbia had proposed and/or implemented such policies or initiated pilot programmes.

Source: American Gas Association

FERC Order 636, which was issued in April 1992, was designed to complete the process of restructuring of the wholesale gas industry. Its objective was to subject the industry to greater competitive pressures by increasing customer choice and improving the transparency of pipeline company pricing of transportation services, thereby reducing end-user gas supply costs and encouraging the development of the business. The key elements of Order 636 were:

- ***Open access to transportation and storage:*** Pipeline companies are now obliged to provide access to storage and transportation facilities for all customers on a non-discriminatory basis, including providing accurate and timely information on system availability.

- ***Unbundling of pipeline services:*** The traditional pipeline sales service is split into its component parts, allowing customers to contract separately for gas supply, transportation, storage and backup services. Pipeline companies are no longer allowed to provide gas merchanting services except through affiliate companies. The objective of this unbundling is to force "comparability" of service between pipelines and other merchants, while giving customers more choice as to the types of services they need.

- ***Capacity reallocation:*** Pipeline companies are required to handle reallocation of unneeded transportation and storage capacity returned by shippers, either temporarily or permanently, through an electronic bulletin-board system.

- ***Rate structure:*** Order 636 mandates "straight fixed variable" (SFV) rate design, whereby pipeline charges will have to be broken down into a fixed-capacity charge (reservation or booking fee) and a commodity charge (according to usage). From 90% to 95% of pipeline revenue now comes from capacity charges.

One consequence of this shift was a fall in transportation costs for high-load factor customers such as large industrial end users at the expense of low-load factor customers, especially LDCs[14].

### US Storage Rate Setting

US storage rates are set in a similar way to pipeline rates, but the cost allocation is different. FERC requires 50% of fixed costs (including cushion gas) to be assigned to a capacity/space component and 50% to a "deliverability" component, on the grounds that fixed costs are incurred in both storing and withdrawing gas. Variable costs are assigned to an injection and withdrawal component. Charges for storage, injection and withdrawal are then set on the basis of authorised design capacity levels. FERC is considering deregulating storage where sufficient competition between facilities is demonstrated.

Although the implementation of Order 636 is considered a success by most industry observers, a number of problems and issues have emerged, notably concerning rate setting and pipeline-capacity release.

## Transportation Rate Setting

Despite the regulatory upheavals of recent years, there has been no fundamental change to the traditional cost-of-service approach to transportation rate setting. Pipeline and storage rates remain almost entirely regulated by FERC. Rates are set on the basis of cost, including a reasonable return on investment.

*Table A-2*
**Alternative Transportation Rate Methods for Interstate Pipelines**

| Method | Degree of competition | Basis of service rates | Rate determination |
|---|---|---|---|
| Traditional cost-of-service | Low | Estimated annual operating expenses plus return on investment | Maximum filed rate |
| Market-based | High* | Customer-driven rates for competing services | Market-determined |
| Negotiated/recourse: | | | |
| *Negotiated* | Moderate | Individually negotiated | Market-determined |
| *Recourse* | Low | Traditional cost-of-service rate | Maximum filed rate |
| Incentive-based | — | FERC-company agreed benchmarks | Maximum filed rate |

* FERC measures a company's market power using the Herschmann-Herfhindal Index.
Source: EIA, *Natural Gas 1996: Issues and Trends* (DOE, 1996).

14. A high load factor indicates a flat demand profile throughout the year, and vice-versa. See the glossary for the definition of load factor.

In response to concerns over excess capacity, FERC is considering allowing more flexibility in determining rates, either to allow market forces to exert some influence over rates or to provide incentives for pipeline companies to reduce costs. Table A-2 summarises the features of the main rate-design methods. FERC is evaluating requests for alternative rate designs on a case-by-case basis, but intends to develop generic criteria for non-cost-based ratemaking, notably negotiated and incentive rates:

- ***Negotiated rates:*** The pipeline companies appear to favour negotiated/ recourse rates, whereby a customer may negotiate a rate with the right to choose the recourse cost-of-service rate. FERC is tentatively moving in this direction, but sees only limited scope for allowing the market to set rates, since the interstate business is still largely monopolistic. Several applications for negotiated rates have been conditionally approved by FERC, but only one has been given full approval. FERC continues to require standard terms and conditions, to ensure that companies do not enhance service to flexible customers at the expense of others, but this policy is under review. The industry is pushing strongly for more flexibility in this area. Capacity turnback (see below) is expected to increase the pressure from pipeline companies for more flexibility in ratemaking.

- ***Incentive rates:*** FERC is keen to encourage incentive-based rate mechanisms that require pipeline companies to share efficiency gains with their customers. FERC no longer requires that pipelines demonstrate quantifiable benefits or that such rates do not exceed cost-of-service rates. Benchmark performance rate-making is one concept under review. The industry, however, seems to be less enamoured of the concept of incentive rates, arguing that there are few efficiency gains left to be had following the severe cost shake-outs of recent years.

In most cases of expansion to existing pipeline capacity, FERC now adopts the "rolled-in" rate-setting principle whereby the additional cost incurred is included in the overall cost base for calculating minimum revenue needs and rates. In this way, existing pipeline customers share the cost of providing capacity for new customers. In the past, FERC has adopted the incremental-rate principle under which the cost of pipeline expansion is allocated solely to new customers.

## Capacity Release

Although the size of this market continues to increase (see next section), a number of problems with the capacity-release market have emerged, and FERC is continuing to address them:

- ***Technical difficulties***, resulting from a lack of standardisation of bulletin boards, led FERC to enact regulations based on protocols developed by the Gas Industry Standards Board, which was set up by the industry for that purpose. FERC has set a deadline of 1 June 1999 for all pipeline transactions to be available on the Internet.

- ***Coordination of multiple contracts***. It is difficult for a shipper looking to book capacity to acquire several segments of a line simultaneously, mainly because of time lags of 2 or 3 days in posting bids and completing transactions.

- ***Released-capacity rates*** are considerably lower than regulated rates during the non-heating season. During the heating season, rates are capped by FERC at the regulated rate, although in many cases the true market value would be considerably higher. This restriction has led to the emergence of an unregulated, informal "gray market", in which LDCs, shippers and pipeline companies are rebundling gas and capacity in a single delivered price; the implicit transportation rate in the bundled price can be much higher than the regulated rate. There is very little information on how big this market is, but many believe it to be substantial. FERC is reviewing the case for removing the cap. It is concerned, however, that doing so would allow major shippers to overbook primary capacity on a heavily utilised line and divert the surplus to the secondary market, where it could earn excessive profits.

- ***State regulation*** is also significantly affecting the capacity-release market: in some cases, state regulators do not allow the LDC to keep any of the revenue clawed back through capacity release. This removes the incentive for the LDC to release the capacity at all or to seek the highest possible price.

## Deregulation of the Retail Market at the State Level

In recent years, LDCs have offered industrial customers and some commercial customers an increasing array of options and services, including varying degrees of transportation, storage, and balancing service as well as access to upstream pipeline capacity. Today, around 75% of retail sales to industrial customers in the US involve unbundled LDC services and gas supply, while for commercial customers the percentage is around 25%. Virtually all residential customers, by contrast, continue to receive a bundled service.

Small-volume commercial and residential customers in many states are now being provided with opportunities to purchase their supplies in the marketplace. In the past two years, a significant number of residential pilot programmes have been proposed by LDCs, with the backing of state regulators. These programmes seek to allow residential customers to choose their natural gas supplier. Marketing companies are allowed to aggregate customers, so that the market can be served in an efficient manner, with the LDC still providing the traditional transportation services, including metering, as a natural monopoly.

At present, some 20 states and the District of Columbia have launched either residential pilot programmes or broader customer choice programmes. Some of these states, including California, Georgia, New York, and Pennsylvania and utilities in Maine, Massachusetts, Montana, New Mexico, Ohio, and Oklahoma, have already proposed or decided to extend retail unbundling and choice of supplier to all their customers within a specified time. Those projects will provide supplier choice to more than 14 million residential homes. They cover potential demand of 1.3 tcf or more than a quarter of total residential consumption. In toal, almost 70% of the gas consumed today could be purchased from non-utility sources when these LDC unbundling programmes are in place.

Providing unbundled services to residential customers poses a host of questions for LDCs, state regulators, and marketers, and for customers themselves. Issues for regulators and LDCs include:

- Development of new contractual relationships with marketers.
- A need to redefine the utility's public service obligations, such as tariff uniformity and security of supply, and the resulting costs of those services.
- Distribution, storage and balancing rate design.
- The definition of those unbundled services that could be offered competitively: billing, metering and equipment repairs.
- Reassignment of upstream pipeline and storage capacity held by the LDC.
- Collection and administration of transition costs, including stranded asset costs.

There is an expectation that current retail unbundling programmes will be rolled out in a gradual fashion. Eventually, they will cover most, if not all, small residential and commercial customers, although there is great uncertainty about how rapidly this will happen. Transition costs, particularly those associated with upstream contractual obligations, will probably be the biggest drag on the development of retail competition. There may also be a lack of political will to push the process forward in some states, where regulators are unable to demonstrate adequately the short-term benefits of competition in the form of lower gas bills. Reassignment of existing capacity contracts from LDCs to marketers, which is expected to be a primary means of avoiding big stranded asset costs in some states, also limits the scope for cost and price reductions, and therefore the political attractiveness of retail unbundling.

## CANADA

### Deregulation of the Wholesale Market

Deregulation of the gas sector and the emergence of competition evolved in Canada in much the same way as in the United States. In the 1970s, prices throughout the gas chain were regulated on a cost-plus basis by the National Energy Board and by provincial regulatory bodies. TransCanada Pipelines had a virtual monopoly over gas transmission and gas purchasing. Dramatic increases in export prices to the United States, set according to a bilateral government-agreed formula, coincided with the emergence of surplus gas supply in the United States in the late 1970s and early 1980s. This resulted in serious financial problems for TransCanada, which was committed to lifting minimum volumes of gas under long-term take-or-pay contracts. By the mid-1980s, the federal and provincial governments agreed on the need for a more market-oriented gas policy. In 1986, wellhead gas prices were decontrolled and mandatory open access to high-pressure transmission was introduced under the NEB Act. TransCanada and other pipeline companies were required to unbundle and form affiliate companies for their marketing activities.

Unbundling and third-party access were extended in the late 1980s to local distribution in many cases to allow large industrial end users and power generators to buy their gas directly from producers. In most provinces, small residential and commercial customers are also allowed to buy their gas directly from producers or marketers, but they are obliged to resell the gas to LDCs at the city gate and purchase the gas back at regulated prices at the point of delivery (see below).

In spite of the general tendency towards deregulation, both imports and exports of natural gas are still regulated by the NEB. Gas can be exported under the authority of a short-term order (less than two years) or a long-term licence (up to 25 years). Short-term export orders are easily obtained, and once obtained are routinely renewed, while long-term licences require a public hearing under the Market-Based Procedure (MBP). This procedure is the Board's current mechanism for fulfilling the NEB Act's requirement that it should grant licences only if it finds exports to be in the public interest. When considering a licence application, the NEB shall "satisfy itself that the quantity of gas to be exported does not exceed the surplus remaining after due allowance has been made for the reasonably foreseeable requirements for use in Canada, having regard to the trends in the discovery of gas in Canada"[15].

Maximum pipeline and local distribution rates continue to be regulated by the NEB and provincial regulators. The rate-design process is very much the same as in the United States: applications for rate changes are examined on the basis of information on the company's total costs of providing service, often by means of a public hearing. A group of smaller pipelines is regulated on a complaints basis. The NEB uses the same straight fixed variable approach as in the United States for allocating costs to the capacity and commodity elements[16]. The NEB, like FERC, is considering alternatives to traditional cost-of-service regulations to provide incentives for pipeline companies to reduce costs and enhance the quality of service. Some pipeline companies have already agreed to absorb some market risk in return for the opportunity to increase returns when market conditions are favourable. For example, under a recent rate settlement with Westcoast, pipeline

15. Export Licensing Criteria, Section 118 of the NEB Act.
16. Canadian gas producers enjoyed a competitive advantage over their US counterparts prior to FERC Order 636, because usage charges were lower, allowing them to move incremental volumes of gas to US markets at a lower marginal cost.

rates now fluctuate along with gas prices. The Alberta government, which regulates the NOVA pipeline, has recently made it subject to traditional cost-of-service regulation, a departure from many years of regulation on a complaints basis.

Most regulatory bodies try to design transportation tolls (rates) that are non-discriminatory and based on cost of service, as in the United States. For some pipelines, however, tolls are «postage stamp» designed, which means that the users do not necessarily pay charges that reflect the distance over which gas is carried. For other pipelines, tolls are strictly distance-based. Many pipelines (TCPL, for example) combine postage-stamp and mileage-based concepts into zone-based tolls, where transportation costs and charges are divided among mileage-based zones.

Over the past few years, there has been debate over the use of incremental tolls versus rolled-in tolls, under which the costs of pipeline expansion are carried by both old and new shippers. Like FERC in the United States, the NEB has generally approved the rolled-in rate principle.

Although primary transportation rates are regulated on a cost-of-service basis, contracted capacity can be released on an unregulated secondary market. Unlike FERC, the NEB places no restrictions on the release and resale of unneeded pipeline and storage capacity by marketers and LDCs.

## Full Deregulation of the Retail Market

As in the United States, Canadian policy makers and regulators are considering extending competition at the retail level to include the smallest consumers. At present, in most provinces, large industrial consumers are able to contract for gas supplies and transportation and related services separately from purchases of gas supplies. Core market consumers including small commercial and residential end users are also allowed to buy gas directly but are required to resell the gas to the LDC at the city gate or further upstream. The price at which the LDC buys the gas from, and resells it to, the end user is regulated by the provincial regulatory bodies based on the LDC's weighted average cost of gas purchases and actual distribution costs, including a profit margin. Ontario was the first province to allow such direct sales.

The Ontario Energy Board (the provincial regulator), in the face of demands for more competition in retailing gas to small consumers, has proposed full unbundling of LDCs' distribution and retail (supply) activities. A decision is expected soon. Unbundling will probably require changes in provincial legislation.

# 4

# IMPACT OF RESTRUCTURING ON GAS CONTRACTING AND PRICING MECHANISMS

Restructuring has resulted in a more competitive and market-driven North American natural gas industry. The manner in which gas supplies and transportation and storage services are contracted for has changed radically, and the risks of doing business have shifted among market participants. A greater diversity of separately contracted services has emerged, including gas purchasing, transportation and storage, market hub services, marketing and financial risk management. This has resulted in a huge increase in the number of transactions and the complexity of contracting for both gas supplies and transportation and storage services. Table A-3 compares gas contracting before and after restructuring.

*Table A-3*
**Natural Gas Contracting in North America**

| Before Mandatory Open Access | After Restructuring |
|---|---|
| **At Wellhead** | |
| Producers contracted to sell gas to pipeline companies. | Producers contract to sell gas to:<br>– End users,<br>– LDCs,<br>– Marketers, including pipeline affiliates, who sell to end users and LDCs. |
| Prices regulated by FERC. | No price controls. |
| Pipeline companies aggregated supply for customers. | Customers aggregate supplies on contract with producers or marketers for this service. |
| Pipelines responsible for supply reliability. | Customers responsible for supply reliability. |
| **Downstream** | |
| Gas customers obtained gas from pipeline companies through bundled sales and transportation service. | Customers contract separately for gas from any seller and transportation from pipeline companies. Customers can buy a bundled service from marketers. |
| Transportation typically along one path, often involving a single pipeline company. Interconnections used mainly for emergencies. | Customers determine the least-cost combination of transportation route and source of gas supply. |
| Operational adjustments to maintain system integrity handled entirely by pipeline companies. | Customers are liable for penalties if they do not meet scheduled volumes and match receipts and deliveries within tolerances. Services available to avoid or reduce penalties. |
| Pipelines companies controlled most storage for seasonal load balancing and operational control. | Customers are responsible for reserving adequate storage to meet peak day requirements. |
| Pipeline companies offered interruptible service when capacity not fully utilised. | Firm shippers can release excess pipeline capacity and recoup part or all of reservation costs. |

Source: EIA, *Natural Gas 1994: Issues and Trends* (DOE, 1994).

Key changes in contracting for gas include:

- Emergence of new market players and relationships.
- Changes in contractual terms for gas supply and transportation.
- Development of spot and futures markets and market centres.

## NEW PLAYERS AND RELATIONSHIPS

Restructuring has led to the emergence of new players in the North American gas industry and fundamental changes in their commercial and contractual relationships. A key requirement of restructuring in both the United States and Canada was the separation between accounting and management of physical pipeline services and gas marketing and trading activities. Most pipeline companies have reorganised their corporate structures, setting up affiliates responsible for gas marketing, gathering, risk management, balancing and basic transportation services. A number of new marketing companies have entered the market, offering a similar range of services including rebundled packaged services to end users and LDCs.

Contractual relationships have become more complex. End users and LDCs have the option to contract with marketers for bundled services, or contract for gas supply, transportation, storage and other services separately. Pipeline customers who formerly received gas supply under a single bundled contract must now contract separately to buy the gas itself (see Figure A-9). Pipeline companies are required to offer the same non-preferential transportation terms to their marketing affiliates as to third-party customers. Before unbundling, customers bought gas almost solely from the pipeline companies. Customers have generally become much more knowledgable about the operational and financial management aspects of the industry. Customer choice has expanded, while transaction costs have increased.

The increase in shipper options has posed some additional technical and operational challenges to both pipeline companies and shippers. New rules have been set up to ensure the maintenance of system integrity, involving flow control and monetary penalties:

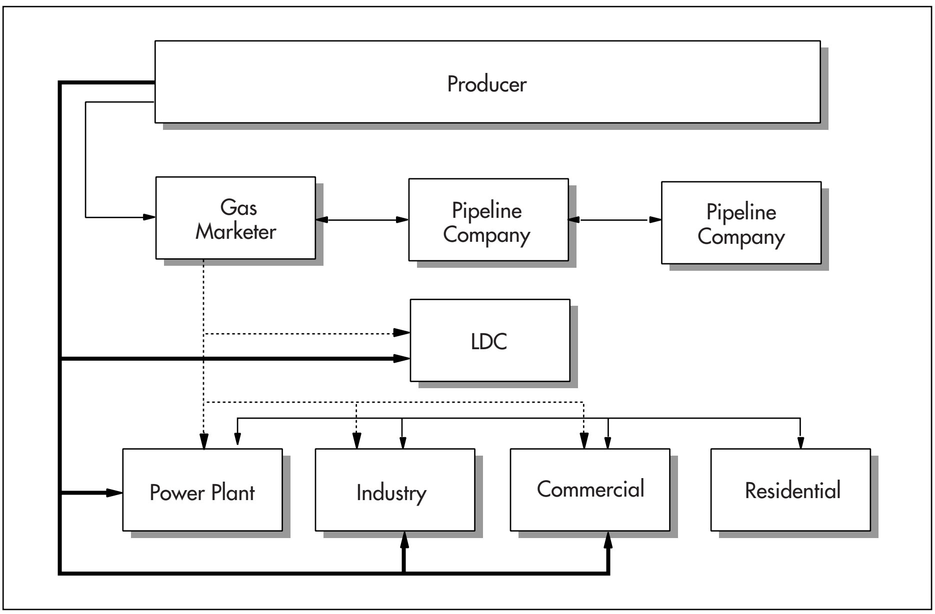
- ***Flow control:*** Existing methods, such as operational balancing agreements and curtailment, which ensure that shippers take or inject no unscheduled amounts of gas and that shippers' injections of gas are matched by withdrawals from the same system over a specified period of time have been adapted to new market conditions. Pipelines may also use emergency orders known as Operational Flow Orders (OFOs) that require shippers to inject or withdraw gas at specified points on the system at short notice.
- ***Monetary penalties:*** Customers who fail to observe their agreed-upon schedules for gas takes, to maintain supply balances or to respond to OFOs may incur substantial penalties:

— Pipeline companies usually set penalties for OFO or curtailment violations at very high levels ($5-25/Mbtu), since these pose the biggest threat to system operation.

— Scheduling penalties, beyond a tolerance level of 5% to 10%, are typically set at the interruptible rate (around 25 cents/Mbtu), but large overruns can incur much higher levels — up to $25/Mbtu.

— Imbalance penalties are usually assessed on a monthly basis as a premium or discount to the prevailing spot price.

*Figure A-9*
**Principal Financial Transactions Paths Between Gas Buyers and Sellers**




# CONTRACTUAL TERMS FOR PHYSICAL GAS SUPPLIES

Prior to restructuring, most gas was sold under long-term fixed-price contracts, either for firm or interruptible delivery. Restructuring has led to increased diversity in the terms and conditions under which gas supplies are traded. Key changes involve contract length and size, and gas-pricing terms.

## Length and Size of Gas Supply Contracts

On average, the length of gas supply contracts has diminished significantly since deregulation started, although there has been a move back towards long-term contracts in the past few years as surplus gas production capacity has declined.

Precise figures are not available, because gas sales contracts are confidential, but short-term, mid-term and long-term contracts are now thought to account for around a third each of final physical gas purchases in North America as a whole.

Short-term contracts for physical delivery of a fixed volume of gas for one month or less provide purchasers with flexibility in meeting sudden unexpected shifts in demand and in balancing supply with load. These allow customers with fuel-switching capability to profit from relative fuel price movements. Such contracts take the form of private, off-exchange spot or cash deals, or of futures exchange contracts. The latter can be done through a standard contract or through Exchanges of Futures for Physicals (EFPs):

- ***Spot deals:*** Many spot contracts are finalised during a period at the end of the month preceding delivery called "bid week". Spot contracts have become very standardised. They normally involve a fixed daily volume with little variation over a set period of up to as month, at a fixed market price on the day the contract is completed. Companies usually establish their credit-worthiness with each other to facilitate the contracting process. In recent years, the share of contracts of less than two years in total US imports from Canada has increased to well over half. However, the size of the North American one-month spot market has declined with the growth of futures markets.

- ***Futures contracts:*** Most deliveries based on futures contracts are through EFPs, whereby two parties with opposite futures positions agree to make actual delivery rather than simply cashing out their positions, as is the norm in most commodity futures markets[17]. In the first half of 1995, deliveries of this kind amounted to about 170 trillion Btu (c.17 tcf) per month — equivalent to almost 10% of total US supply. Roughly 90% of futures-based deliveries are through EFPs. The increasing use of EFPs is explained by the flexibility this mechanism provides buyers and sellers in setting delivery terms and managing price risk. The fact that deals are under the scrutiny of the NYMEX lessens the risk of default for reasons other than *force majeur*.

Mid-term contracts cover gas deliveries of up to three years, though most are for one year or less. Such contracts can be hedged by futures contracts, which now extend to 36 months ahead. Most such contracts are characterised by fixed volumes per day or per month with modest variation, although some "swing" contracts specify variable volumes. Any daily or monthly variability carries an additional service fee in addition to the base price for the gas. Most LDCs rely on mid-term contracts for much of their gas needs.

Contracts for supplies of more than three years are usually for fixed monthly volumes of gas. Some contracts have take-or-release conditions, whereby the supplier has the right

17. An EFP may be negotiated at any time before the close of the market for a particular contract by two parties holding opposite positions on that contract. An EFP delivery may take place at a location other than that specified in the futures contract and the actual price may deviate from the futures prices as negotiated by the two parties.

to reduce volumes or cancel the contract if the buyer underlifts. However, the buyer may sell on any gas he does not need under a back-to-back long-term contract or on the spot market. Other contracts specify a variable reservation fee to compensate the supplier for any increase in costs incurred in arranging long-term supplies. Take-or-pay (TOP) provisions are now uncommon and mostly apply to contracts to supply co-generators. Where a TOP clause is agreed, the threshold is normally less than 70% to 80% (compared to over 90% before deregulation). A variant of TOP, deficiency payments, has emerged in some long-term contracts since deregulation. In these cases, a contract specifies a minimum level of revenue and provides the buyer an incentive to lift threshold volumes of gas. Typically, threshold levels are around 60% to 75% of Annual Contract Quantity.

Long-term contracts are of primary interest to suppliers looking to cover fixed costs associated with expanding production capacity, and to buyers such as LDCs and co-generators looking to secure reliable long-term fuel supplies. According to an American Gas Association survey, the vast majority of gas bought by LDCs is under long-term contract, although some LDCs expect to increase spot purchases ultimately to meet about a third of total needs[18]. Most spot purchases are made during the non-heating season for injection into storage or for interruptible sales to industry and power generators.

The greater diversification in gas buyers' supply portfolios brought about by the fragmentation of the industry and the emergence of a large number of gas marketers has resulted in a greater number of individual contracts covering on average smaller daily and monthly volumes of gas. According to the National Energy Board, the average size of Canadian LDC's contracts declined from 1.27 bcm/year in 1985 to 0.24 bcm in 1991[19].

## Gas Pricing Terms

Short-term contracts typically specify a fixed price for gas supplied, the price being determined by market conditions at the moment the deal is struck. Mid-term contracts, by contrast, usually contain price index formulae whereby the price paid each month for gas delivered is adjusted for movements in published spot or futures prices. Buyers and sellers have the option of locking in the actual price at the beginning of the contract period by selling short or buying long on futures markets.

There are numerous types of pricing provisions in long-term contracts:

- The gas price is indexed to a published spot or futures gas price, plus a reservation charge. This is the most common type of pricing provision in both the United States and Canada, both for domestic sales and export.

- The gas price is indexed to a spot/futures price plus a premium negotiated between seller and buyer. In the case of large-volume contracts between gas

18. American Gas Association, *LDC Gas Supply Portfolios* (Foster Associates, 1994)
19. National Energy Board, *Annual Report 1992*

marketers and LDCs in Canada, prices are typically indexed to NYMEX futures prices plus an "Empress basis differential". This is the difference between the price of gas delivered to the Henry Hub and the price of gas delivered at Empress, a key pipeline junction on the border between the provinces of Alberta and Saskatchewan at the Western inlet to the TransCanada pipeline system.

- The gas price is indexed to the prices of alternative fuels. Some long-term Canadian export contracts and sales to industrial end users are priced this way.
- The gas price is indexed, in the case of some power generators or co-generators, to the price of electricity to lock in a margin and guarantee a return on assets.
- Fixed price. Contracts priced this way represent a small proportion of total gas purchases.

Some long-term contracts provide for the possibility of the buyer's or seller's re-opening negotiations on price terms at specified times if the effective price no longer reflects market conditions.

Most large buyers of gas seek a mix of pricing terms in their contract portfolios. Many LDCs and other large buyers are using or are considering using hedging strategies to manage their gas cost risks through the use of futures markets.

### Coordination of Short-Term Gas and Transportation Capacity Requirements

The increasingly short-term nature of the natural gas market and the fragmentation of supply portfolios has increased the complexity of coordinating short-term gas supply with transportation capacity needs. At the end of each month, during "bid week", deals are struck for the sale and purchase of gas and nominations are made for transportation capacity for the next delivery month.

Futures trading has added a new dimension to bid week. The final day for trading on a futures contract for a given delivery month is 6 to 8 days before the beginning of the delivery month. Almost all pipeline nomination deadlines fall on or just after the close of the futures contract. When the futures price is settled, this influences spot deals made just before the nomination deadline. The speed of handling the rush of spot deals and nominations has been greatly enhanced by information technology, notably electronic bulletin boards.

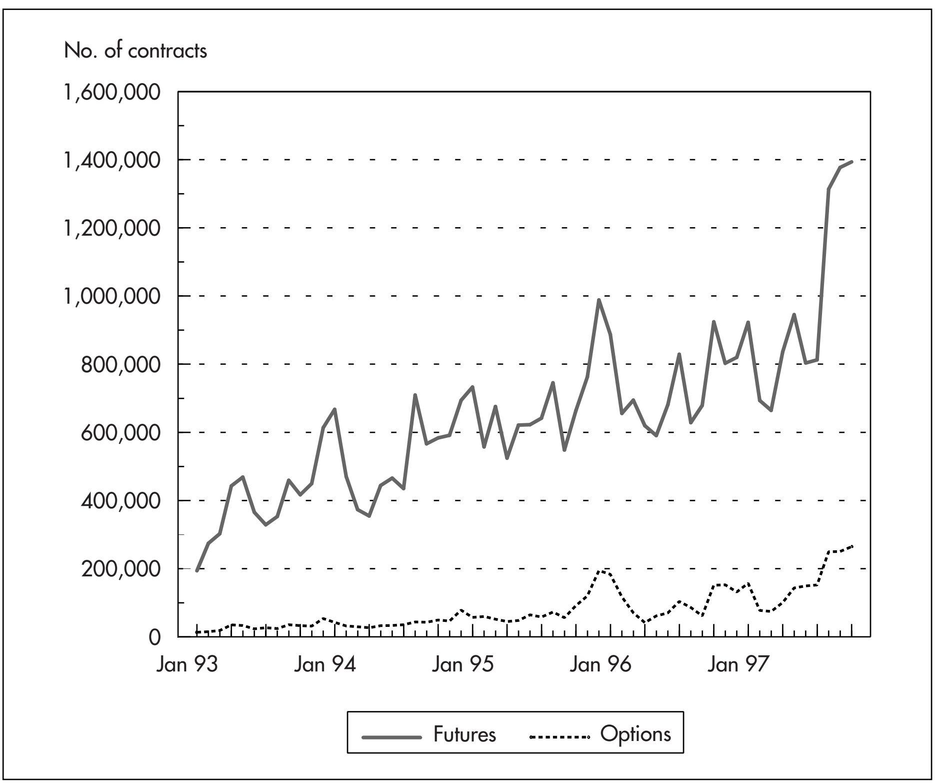
## DEVELOPMENT OF SPOT AND FUTURES MARKETS AND MARKET CENTRES

The spot or cash markets for gas emerged in the mid-1980s in the United States in response to the partial deregulation of wellhead prices, which allowed producers to sell gas not tied up under long-term contracts. Today, active spot or over-the-counter (OTC) trading takes place at a variety of hubs or market centres located at various pipeline receipt points in major producing areas, pipeline delivery points in the main consuming regions and at locations where Canadian gas is imported into the United States.

The volatility of gas prices that emerged with restructuring led to the development of a variety of financial management tools to allow gas traders to hedge fixed-price risks over the medium and long term. The first futures contract was launched on the New York Mercantile Exchange (NYMEX) in April 1990, for delivery at Henry Hub in Louisiana. A second contract was launched by the Kansas City Board of Trade (KCBT) in August 1995 for delivery at the Waha Hub in West Texas. Trading has increased steadily since the launch of these contracts. Gas marketers have been the most active participants in futures trading, but interest from producers and LDCs is growing. Options markets on the two exchanges have also grown since their inception (see box below). Figure A-10 shows the growth in Henry Hub futures and options contracts on NYMEX, the larger of the two exchanges.

*Figure A-10*

**NYMEX Trading Volumes in Henry Hub Futures and Options Markets**




Note: One contract is for 10 000 Mbtu.
Source: EIA/DOE

As well as providing opportunities for hedging and speculation, futures markets also offer a means of price discovery and serve as price indices for physical gas contracts (see below). Although their primary role is not necessarily to provide for physical delivery, there has been an increase in the use of futures contracts for this purpose (see above). Futures markets, therefore, complement spot markets. Two new futures contracts based on delivery in Alberta, Canada and the Permian Basin in West Texas were launched by NYMEX in 1996 but have so far failed to attract significant interest, primarily, because players preferred to continue to trade gas on existing spot and forward markets.

Market centres have emerged as a key aspect of restructuring, under which shippers are permitted flexibility in delivery and receipt points. In the United States before Order 636, shippers were allowed to change receipt points without penalty but not delivery points. This greatly limited flexibility in moving gas to market and hindered capacity release. Order 636 defined a market centre as "an area where gas purchases and sales occur at the intersection of different pipelines". Where numerous buyers and sellers come together, the risk of a dominant player's exercising market power is reduced. Market centres have also cut supply and transactions costs, and provide better dissemination of price information and facilitate load balancing.

## Hedging using Futures, Options and Swaps

Hedging to minimise the risk of the spot price's rising or falling can be conducted through futures and options market trading on formal exchanges, or through swaps. A *futures* contract for the sale or purchase of a fixed volume of gas in a future month at a specified delivery point provides a means for a buyer or seller to lock in price. For example, a producer looking to fix the spot price of gas for a future month can sell a contract for that month on a futures market; to complete this hedging transaction, the producer must close its position by acquiring a futures contract to buy the same amount of gas before the contract expires. Futures have two main shortcomings as a hedging mechanism. First, at a given location, spot prices are not always exactly in line with the near-month futures price at the time the futures contract closes. Second, large differences can occur across regional markets, which can limit the effectiveness of futures markets for hedging purposes (known as basis risk). This fact prompted the creation of a second futures market on the KCBT exchange.

An *option*, a type of insurance policy, is defined as the right (but not the obligation) to sell or buy a futures contract at a certain price. Unlike for a futures contract, there is no requirement to pay a margin. The cost of participating is simply the price of the option, paid once and fixed for the duration of the validity of the option. A range of price increments is available to allow the option holder flexibility in determining the degree of price protection desired.

A *swap* is an exchange of cash flows between two parties based on the difference between the price agreed in the swap and the actual spot price. Such deals, conducted with financial intermediaries, are attractive to parties looking to fix prices over several years to support investment loans.

Source: EIA, *Natural Gas Monthly, February 1994* (DOE, 1994)

## CONTRACTING FOR TRANSPORTATION AND STORAGE

Restructuring has led to a fundamental shift in contracting for transportation and other pipeline services, including:

- A shift in the types of transportation service provided.
- A trend towards shorter-term contracts for firm transportation capacity and possibly reduced overall firm reservations.
- Direct contracting for underground storage capacity.

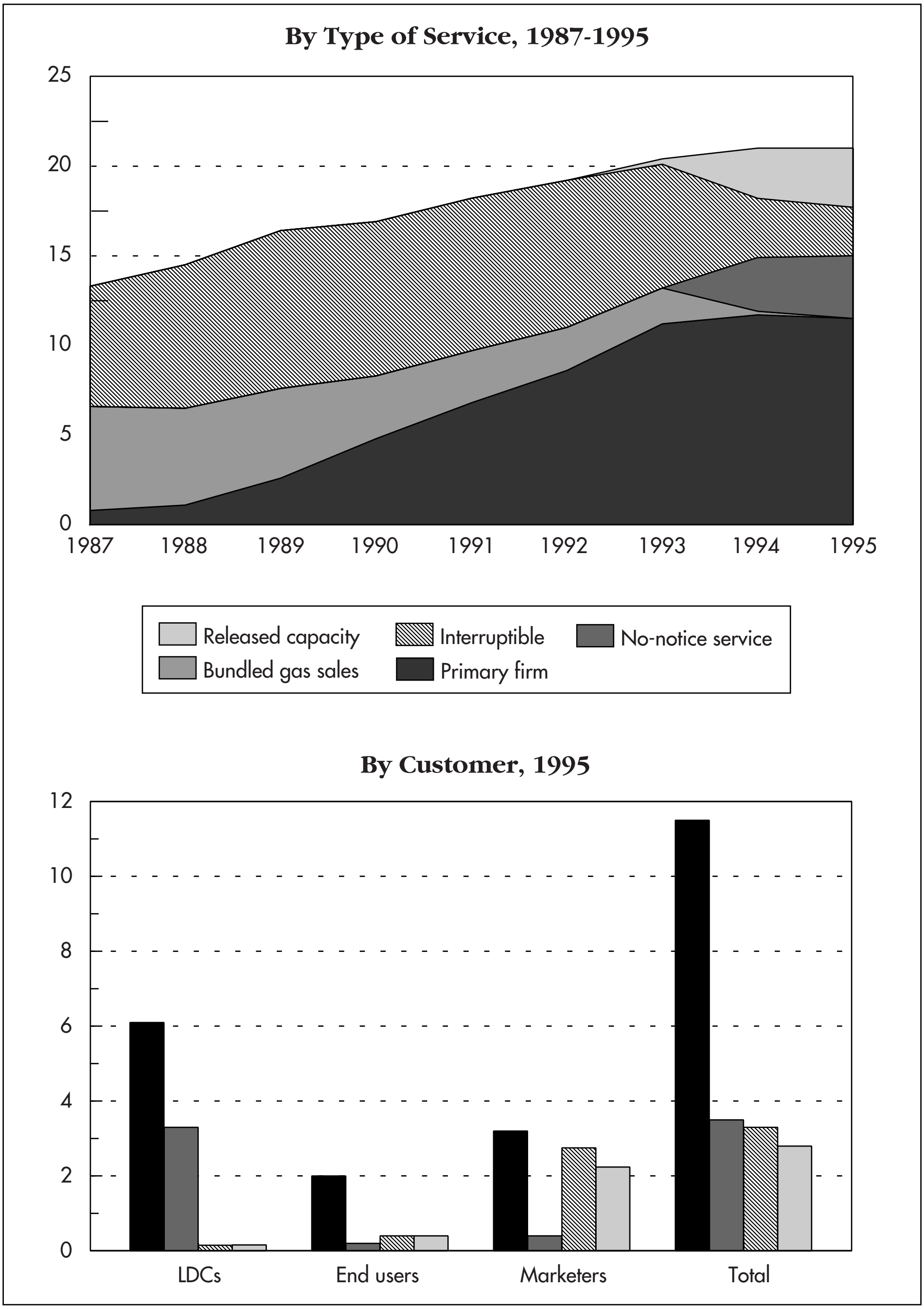
### Type of Transportation Service

Under FERC Order 636, most customers who had firm bundled sales service simply converted their contracts to primary firm transportation. Restructuring also led to a sharp decline in the share of interruptible service, whereby the pipeline company has the right to withdraw capacity at short notice to ensure that sufficient capacity is available for customers who have reserved firm service. This service has been largely replaced by primary firm and premium firm (no notice) transportation[20]. Interruptible transportation accounted for only 14% of total US gas deliveries in 1995, compared with over half in the mid-1980s. Pipeline customers in the past relied on spot market purchases of gas transported on an interruptible basis and back-up sales by the pipeline companies in the event of interruption for around half their requirements. Released capacity traded on the secondary market now represents a significant element in interstate transportation. The type of transportation service varies according to customer type (see Figure A-11):

- LDCs rely most on primary firm and no-notice service in direct bookings with pipeline companies, because of the obligation under state regulation to guarantee supplies on behalf of their customers.
- End users — mostly large industry and power utilities — hold mainly primary firm capacity, but rely to a small extent on interruptible and released capacity because of the potential for short-term fuel switching and commercial pressures to minimise the cost of gas deliveries.
- Marketers, as intermediaries between producers and end-users and LDCs, generally hold a diversified mix of service of which interruptible and released capacity account for about two thirds of their total capacity needs. This mix largely reflects the service needs of the marketers' customers.

20. "No notice" is a premium service created to mimic the quality of service previously available as part of the bundled sales service. The main difference between firm and no-notice service is that under no-notice service a shipper does not incur any penalty for lifting gas beyond scheduling limits applied to firm service negotiated with the pipeline company. The pipeline company provides back-up through near-market storage or by shifting pipeline capacity from interruptible customers.

*Figure A-11*
**US Interstate Gas Transportation Market by Type of Service**
(Quadrillion Btu)




Source: EIA, *Natural Gas 1996: Issues and Trends* (DOE, 1996).

Secondary markets are continuing to grow in importance. The amount of capacity held by replacement shippers in the US capacity-release market has increased rapidly since its inception in 1993, to around 16% of total deliveries (see Figure A-12). The amount of capacity released tends to be highest just before the beginning of the heating season. A significant proportion of released capacity is subject to recall. The primary holder of the capacity who releases it on the secondary market retains the option to take back the capacity, possibly subject to predetermined market or operating conditions. Recall provisions applied to 69% in the 1995/6 heating season and 61% in the 1995 non-heating season. The proportion has fallen from 69% in the 1994/5 heating season and virtually 100% in 1993/4. Transactions on the unregulated Canadian secondary capacity market have also risen in recent years.

The market price of released capacity in the United States remains low compared to regulated primary firm transportation rates. Rates were discounted 65% from maximum rates during the 1995/6 heating season and 83% during the 1995 non-heating season, though discounts were somewhat higher the previous year. The FERC-imposed cap on released-capacity rates at the maximum regulated rate is partly responsible for these discounts (see section 3 above). At times of lowest demand, when there is generally ample spare pipeline capacity available, shippers who have booked capacity to meet peak winter demand are often willing to release unneeded capacity at very low prices. During peak demand periods, the true market value of capacity often rises to well above the regulated rate in the event that capacity is fully utilised. At such times, the cap both prevents the true market value from being reflected in the actual rate and discourages shippers from releasing capacity.

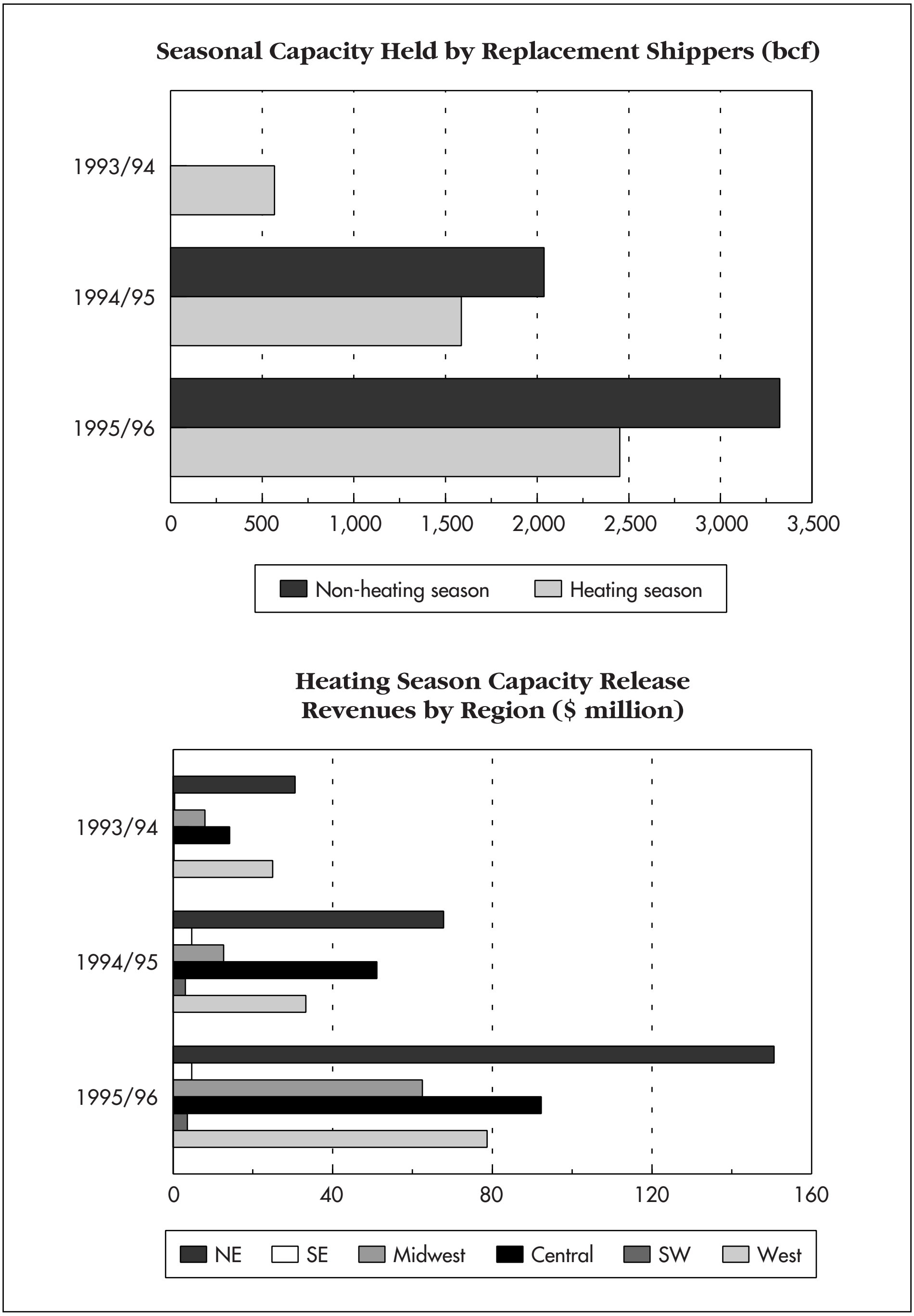
## Size and Length of Transportation Capacity Contracts

While wellhead and city-gate gas supplies are now primarily sold under short- to medium-term contracts, primary transportation capacity, mostly firm, is still mostly under very long-term contracts, typically lasting 10 to 20 years, particularly to LDCs. A key uncertainty facing pipeline companies concerns the possible convergence of transportation-capacity contracting with contracting for gas supply itself. This would be reflected in a decline in the length of contracts for capacity and the possible creation of spot markets in capacity in parallel with existing spot gas markets. There has been a small number of highly publicised cases in the West and Midwest involving the "turnback" of part of the capacity previously held under long-term contracts when those contracts expired. Many pipeline companies expect a growing number of LDCs to turn back capacity and seek shorter-term contracts for the capacity they still wish to take — probably no more than 2 years in most cases. A number of factors contributes to this trend:

- Increased availability of competing services, such as improved access to storage and US and Canadian production.

- Increased cost of capacity reservation under the straight fixed variable rate-design method which penalises low-load factor customers such as LDCs.

*Figure A-12*
**US Capacity Release**




Source: EIA, *Natural Gas 1996: Issues and Trends* (DOE, 1996).

- Offsetting revenue from released capacity is limited by large discounts during the non-heating season and by the rate cap.

- Pressure on LDCs to reduce costs and minimise long-term commitments as competition in retail markets increases. This is expected to lead to lower retail prices and the erosion of the LDCs' customer base.

- Changes in some regional economies have led to lower-than-expected demand.

Capacity turnback, or lower levels of contracted capacity, will affect demand for different types of pipeline services, the secondary market for capacity and the perceived risk of pipeline investments. In particular, it poses a problem for pipeline companies in recovering pipeline investment costs. Increasing rates to remaining customers is generally not a viable solution, since this could drive those customers to other transporters, services and service providers and lead to yet further reductions in capacity reservations. FERC recognises that a departure from the usual SFV rate design method, which recovers all fixed costs from the reservation charge, may be necessary in some cases to make under subscribed capacity more marketable.

Shorter contracts also pose a problem for pipeline companies seeking to finance new projects or capacity expansions: financiers generally insist on long-term capacity commitments to guarantee the viability of the investment. There is some speculation that major oil and gas producing companies may be prepared to commit themselves to reserving some capacity under long-term contracts to ensure that new sources of gas are developed.

## Underground Storage

Gas industry restructuring has fundamentally changed the way storage is used. In the United States, Order 636 required the transfer of responsibility for obtaining peak-day supplies from pipeline companies to LDCs and end users. Interstate storage capacity, which formerly supported the pipeline companies' sales service, was released to the market. This involved assignment of storage capacity to former customers (mainly LDCs) under long-term contracts, with any excess capacity offered to the rest of the market. In Canada, storage was already mostly in the hands of the LDCs, so restructuring brought about little direct change in contracting for storage.

The value of underground storage has risen as a result of deregulation because of the importance of physical daily and monthly balancing and the financial opportunities it provides for arbitraging spot and futures price differentials. Storage provides flexibility in meeting short-term shifts in demand through short-term gas loans, balancing and peaking services. Holders of capacity can also profit from differentials in spot and futures prices. By buying gas to store when the current spot price is low and selling later when the spot price is higher, they can use futures markets to lock in margins. Most North American market centres offer storage as a major service. There has been an increase in both working gas capacity and daily deliverability since 1993, although the rate of annual additions to capacity declined over the period 1993 to 1997. In the past two years, deliverability has increased more rapidly than working gas capacity, reflecting the growing importance of storage for short-term balancing and its value in taking advantage of price volatility on spot and futures markets. There is evidence that existing storage facilities are now being used more efficiently than in the past (see next section).

# 5

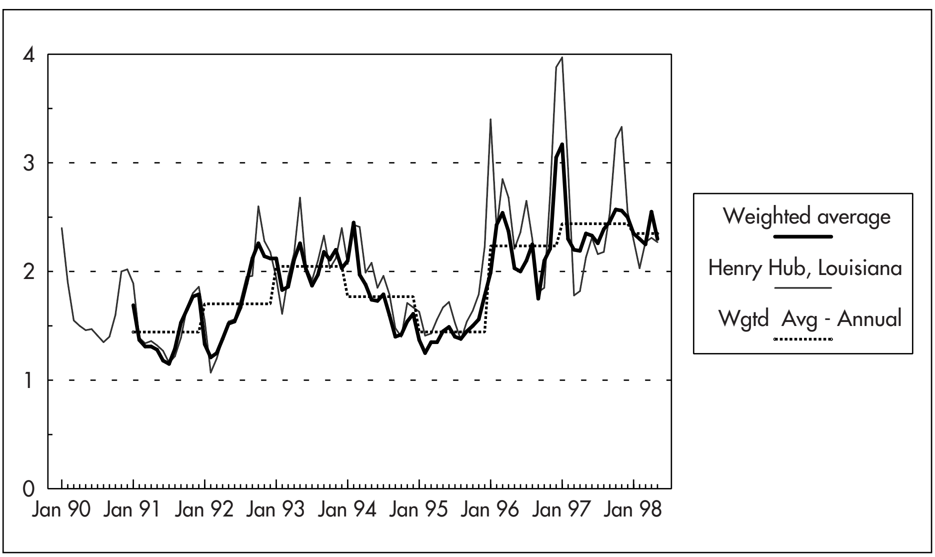
# NATURAL GAS PRICE DETERMINATION

## PRICE TRENDS

The previous section identified the central role played by spot and futures markets in determining natural gas prices in North America. Although most gas is sold under mid- to long-term contracts, prices under those contracts are nonetheless closely linked to spot and futures prices, which are, in turn, closely linked to each other.

An analysis of North American spot gas prices over recent years reveals both a good deal of price volatility — on a daily, monthly and annual basis — and significant differences in price behaviour at different delivery points. Figure A-13 details the trend in the weighted average spot price of gas delivered to US pipelines, and the spot price of gas delivered to the Henry Hub — the single most important physical hub and market centre in North America.

*Figure A-13*
**US Spot Gas Prices Delivered to Pipeline**
(Monthly and Annual, $/Mbtu)




Note: Monthly prices reflect index prices for one month spot contracts at the beginning of the delivery month.
Source: Average prices: *World Gas Intelligence*; Henry Hub: *BTU Weekly*

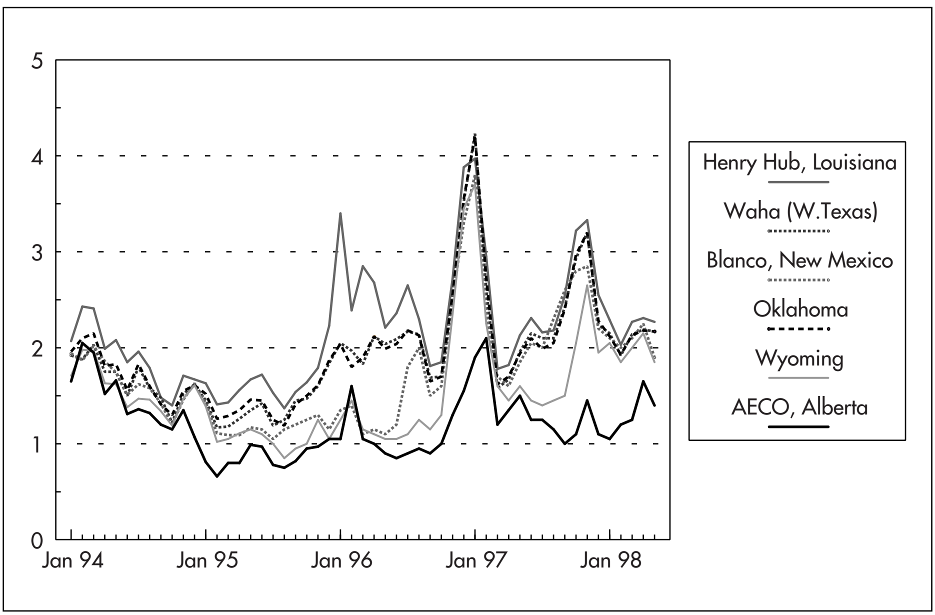
On an annual basis, average spot prices since 1990 have moved within a range of $1.44/Mbtu (in 1991) to $2.41/Mbtu (in 1997). Month-on-month price fluctuations have at times been large, notably in late 1996/early 1997, when a severe cold snap across the United States temporarily caused spot prices to soar. The monthly index price at Henry Hub jumped to $4/Mbtu in January 1996; later that month, the daily price rose to above $10/Mbtu at times. In a similar cold spell in January/February 1996, short term spot prices at Henry Hub surged briefly to over $10/Mbtu. A degree of seasonality in spot prices is evident in most years.

Spot prices vary considerably according to the delivery location. Figure A-14 shows how spot price differentials have widened since 1994, most obviously at times of severe winter weather (1995/6 and 1996/7). The Henry Hub spot price has been the most volatile over this period.

*Figure A-14*

**North American Spot Prices Delivered to Pipeline, January 1994 to May 1998**

(Monthly, $/Mbtu)

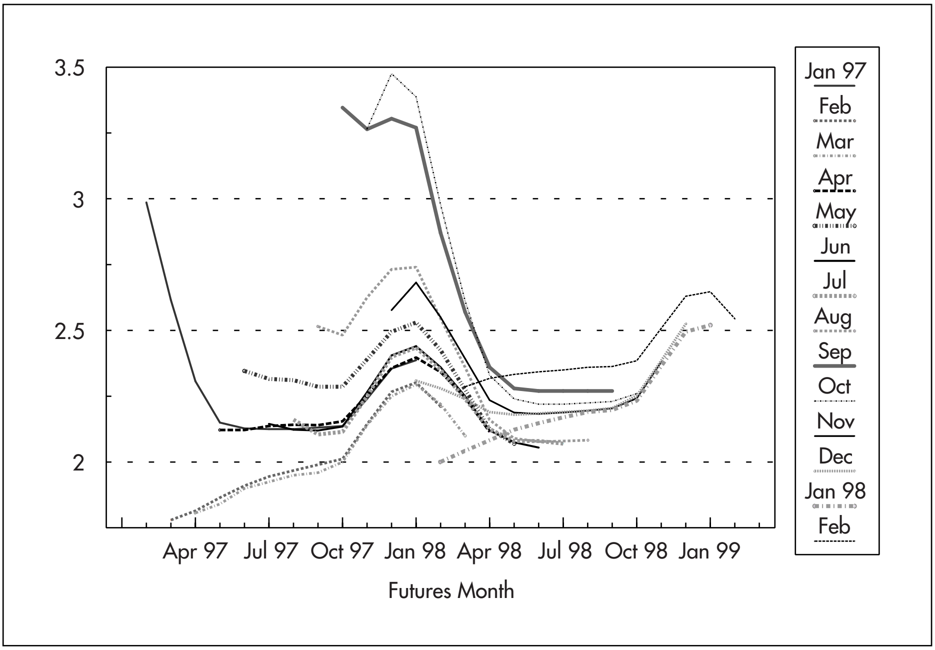



Note: Monthly prices reflect index prices for one month spot contracts at the beginning of the delivery month.

Source: *World Gas Intelligence and BTU Weekly*

The month-to-month variation in spot prices is matched by movements in near-month future prices, which tend to converge with spot prices prior to the termination of futures trading in the near-month contract. Figure A-15 illustrates the pattern of NYMEX futures prices, based on delivery at Henry Hub, over the first nine months of 1997. The nearest month at the beginning of the year — February — traded at just under $3/Mbtu, while a month later the March contract price had dropped to a little over $1.75/Mbtu. Prices of contracts for more distant months tend to be far less volatile, because the role of expectations of weather conditions is far less important.

*Figure A-15*
**NYMEX Futures Settlement Prices, January 1997 to February 1998**
(Delivery at Henry Hub, $/Mbtu)




Source: *BTU Weekly*

A degree of seasonality in more distant months is also evident, with winter months typically commanding a premium of around 30 cents/Mbtu over summer month prices. This differential reflects the typical regulated cost of injecting, storing and withdrawing gas on a seasonal basis out of depleted reservoirs and aquifers[21].

## SUPPLY AND DEMAND FUNDAMENTALS

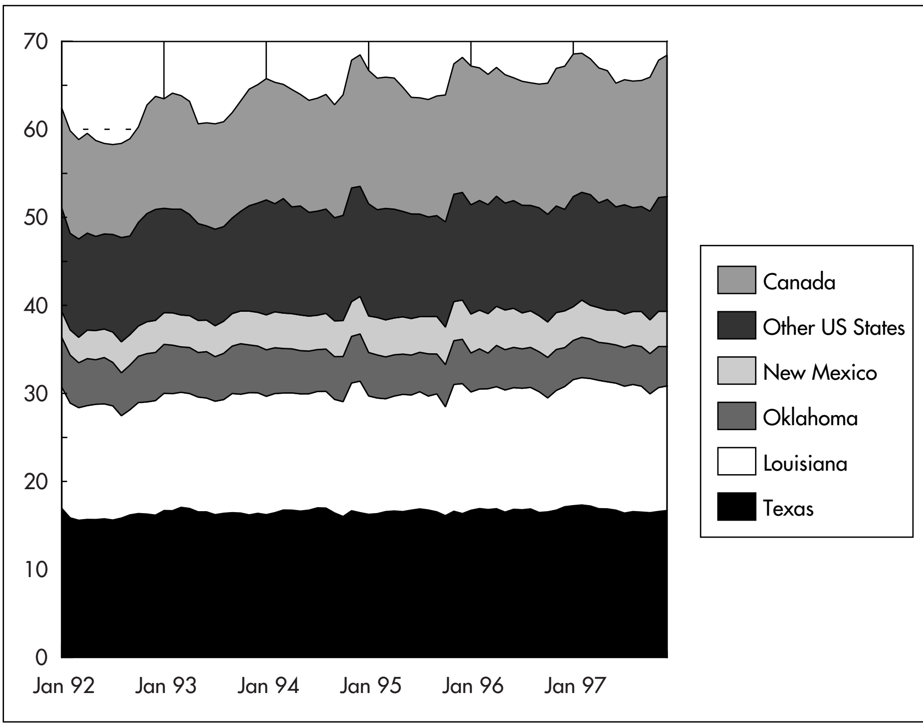
The principles of supply and demand and interfuel competition in gas-price determination, outlined in Part I of this report, can be applied in helping to explain spot gas price movements on North American markets. An analysis of competitive gas-price formation reveals the key role played by the prices of competing fuels as well as the role played by transportation costs and capacity constraints. Such an analysis requires a detailed look at production and supply, consumption patterns and the prices of competing fuels, as well as regional pipeline rates and capacity constraints.

21. See Cedigaz, *Underground Storage in the World* (1995).

## Production, Imports and Storage

Although overall gas production has risen in both the United States and Canada in recent years, there has been little change in the relative importance of the main producing regions. Alberta remains the overwhelmingly predominant source of Canadian gas, while US production continues to come primarily from Texas and Louisiana (see Figure A-16).

*Figure A-16*
**North American Dry Gas Production, 1992 to 1997**
(Bcf/day)




Source: EIA, *Natural Gas Monthly* (DOE), various issues

A major change in US production patterns since the early 1990s, revealed more clearly in Figure A-17, is a reduction in seasonality. In the past, total production fell in late winter and rebounded in the autumn in line with demand. This seasonality, still clearly apparent in 1992, has diminished, though production still tends to rise somewhat from October to November. The reasons for this change are largely economic: in general, it is more efficient to build storage or to sell gas on an interruptible basis than to invest in gas production capacity to meet peak winter needs. Liberalisation of North American gas markets has revealed the true economic cost of seasonal load balancing. It has provided, through the development of spot markets, an outlet for producers to sell their gas in the summer. Although spot prices are generally lower in the summer, the seasonal price differential is usually too small to justify producers shutting capacity, given the large upfront investment costs and the imperative to maximise short-term cash flows. Nonetheless, producers typically choose the summer months to carry out scheduled maintenance work, which largely explains the annual rise in production in the autumn. It is also thought that summer maintenance shutdowns are carried out more quickly than in the past, further reducing the apparent seasonality in production. Canadian production swing, by contrast, remains significant, in part due to surplus delivery capacity in Alberta (see Figure A-17).

Short-term trends in gas production in North America show little sensitivity to price despite the speed with which new on-shore production can be brought onstream in some regions — typically two to three months (see Figure A-18). For any given day, week or month, gas production is virtually fixed.

Imports into the United States — almost entirely from Canada — show slightly more of a seasonal pattern than US production, largely because of the extensive use of Canadian upstream storage (see Figure A-19).

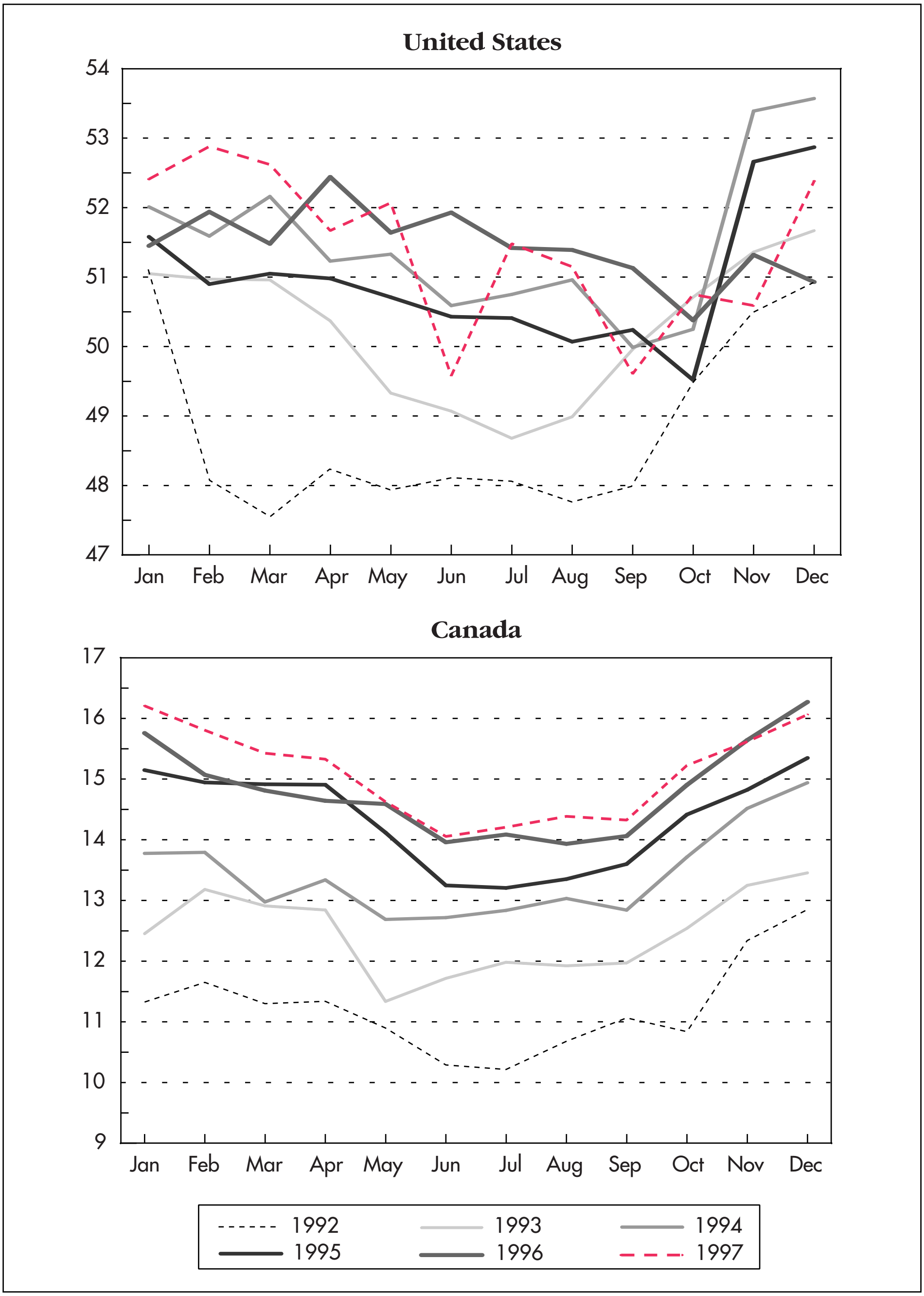
There has been little change in the seasonal pattern of withdrawals and injections over recent years, although the overall amount of gas stored and withdrawn each year has tended to rise — partly because of an increase in residential demand and cold winters in 1993/4, 1995/6 and 1996/7. This is illustrated in Figure A-20. The highest average monthly rate of gas withdrawal ever in both the United States and Canada was recorded in January 1994. The largest heating season rate of gas withdrawal was in 1995/6.

Despite rising production and end-user demand, the levels of working gas in US storage facilities tended to fall in the early 1990s as competitive markets led to pressures to reduce storage costs. This process may have run its course: working gas fell to a recent low of around 750 bcf at the end of March 1996, but rose to just over 1 000 bcf at the same date in 1997 (Figure A-21).

Although storage is still used primarily for seasonal load balancing, it is increasingly used for short-term balancing, peak shaving and to arbitrage futures and forward markets. This has led to increased demand for and use of high-deliverability salt cavern storage serving local demand, located mainly in the Gulf region (Texas, Louisiana and Mississippi). The average number of cycles during the heating season at these facilities (complete depletion and full refill) increased from just over 0.5 in 1991 to more than 1.1 in 1995/6 (see Figure A-22). For those sites connected to market centres, the average number of cycles was even higher. Some salt caverns can be cycled in less than a month, compared with about 5 months for conventional storage.

Figures A-23 and A-24 illustrate recent trends in the relative importance of production and import swing, and of storage in meeting seasonality in the United States and Canada.

*Figure A-17*
**Total US Dry Gas Production, 1992 to 1997**
(Bcf/day)

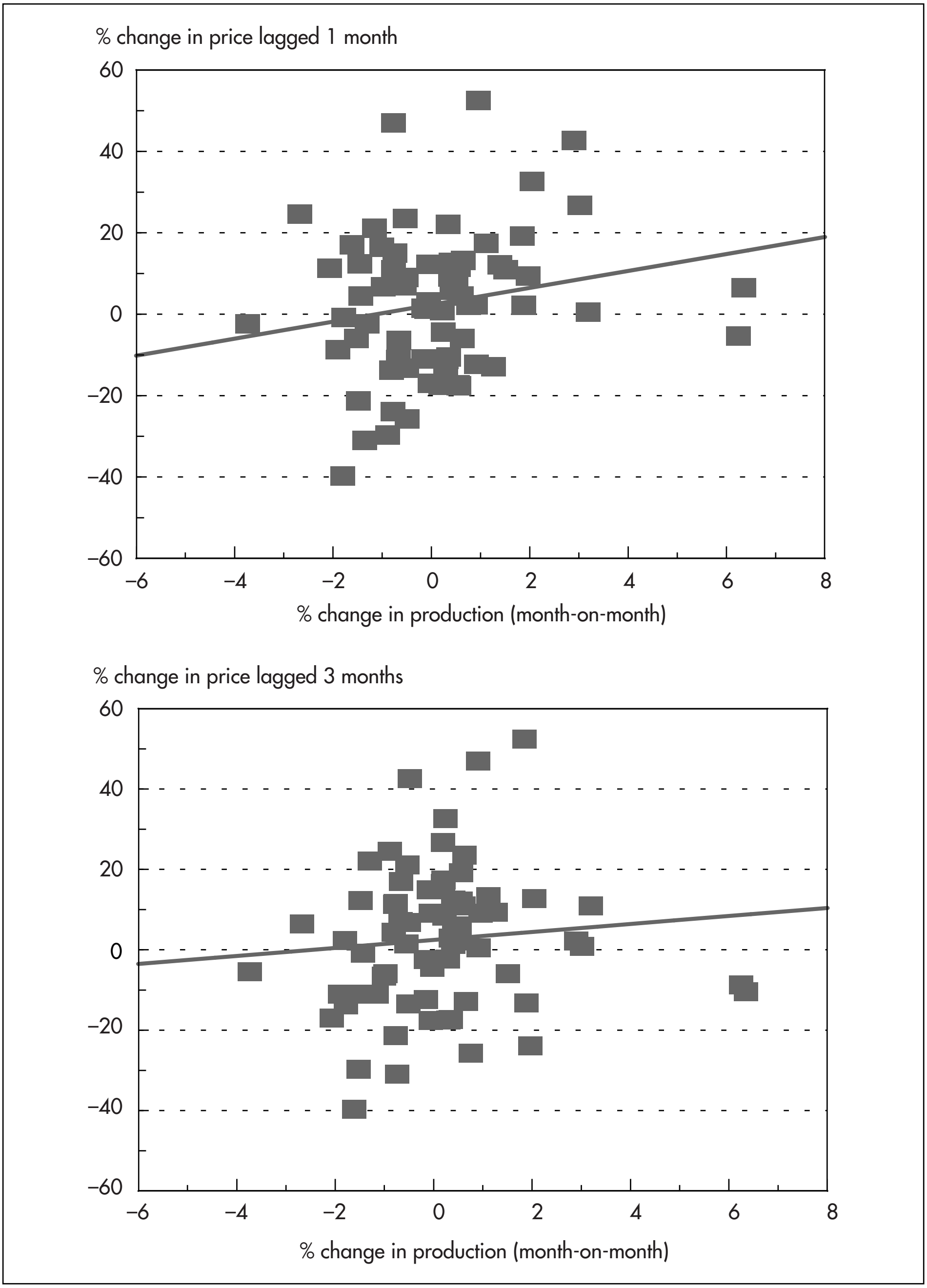



Source: EIA, *Natural Gas Monthly* (DOE), various issues; Statistics Canada, *Crude Petroleum and Natural Gas Production*, various issues.

*Figure A-18*

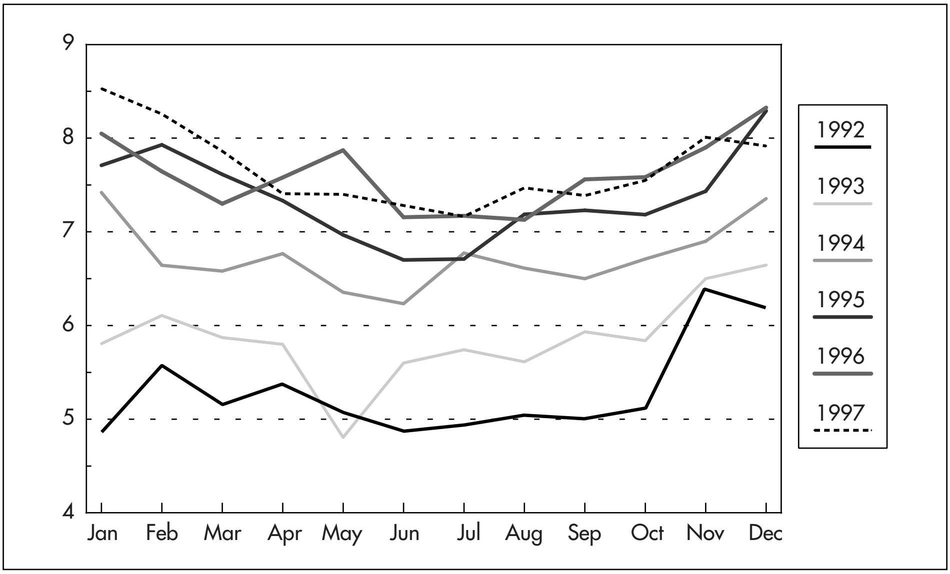
**Responsiveness of US Dry Gas Production to Changes in Spot Price at Henry Hub**

(Month-on-month changes, January 1992 to December 1997)



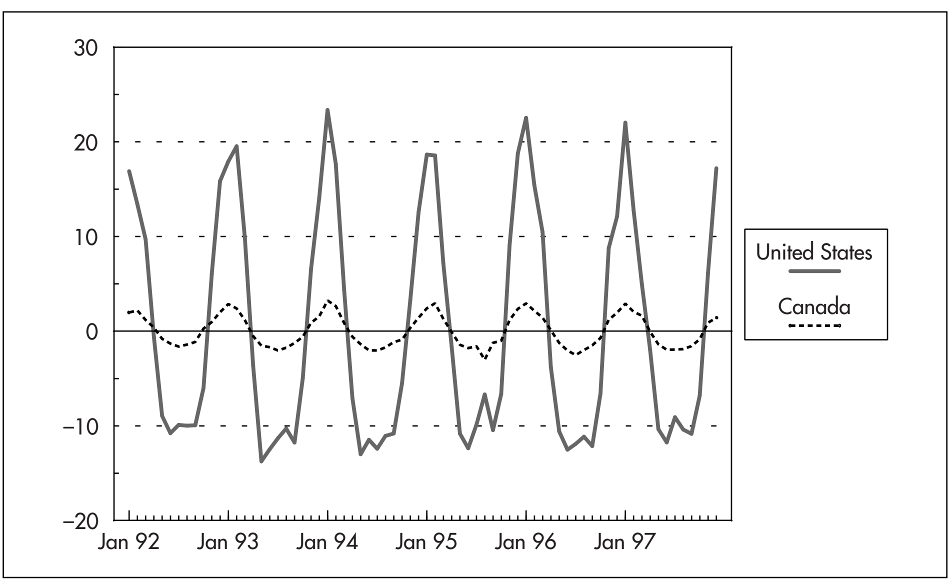

Source: IEA, based on data from EIA, *Natural Gas Monthly* (DOE), various issues

*Figure A-19*
**Net Gas Imports into United States, 1992 to 1997**
(Bcf/day)



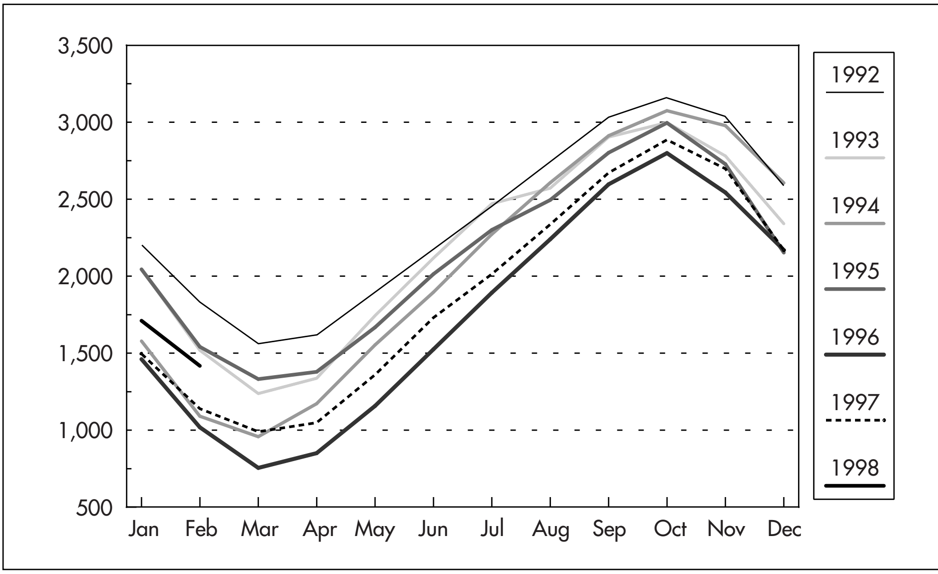

Source: EIA, *Natural Gas Monthly* (DOE), various issues

*Figure A-20*
**US Net Withdrawals of Gas from Storage, 1992 to 1997**
(Bcf/day)



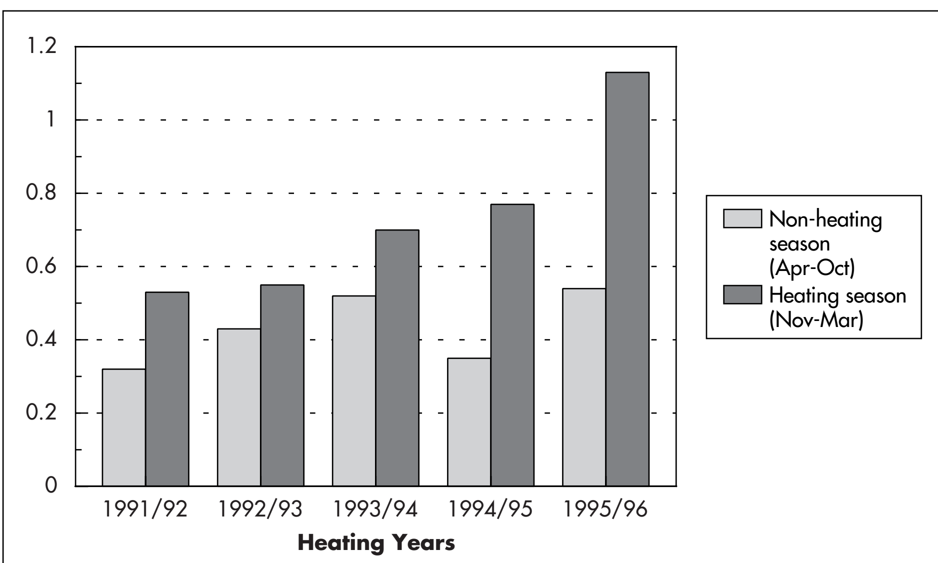

Note: Canada data covers upstream storage only.
Source: EIA, *Natural Gas Monthly* (DOE), various issues

*Figure A-21*
**US Working Gas in Storage, January 1992 to February 1998**
(Bcf at end of month)



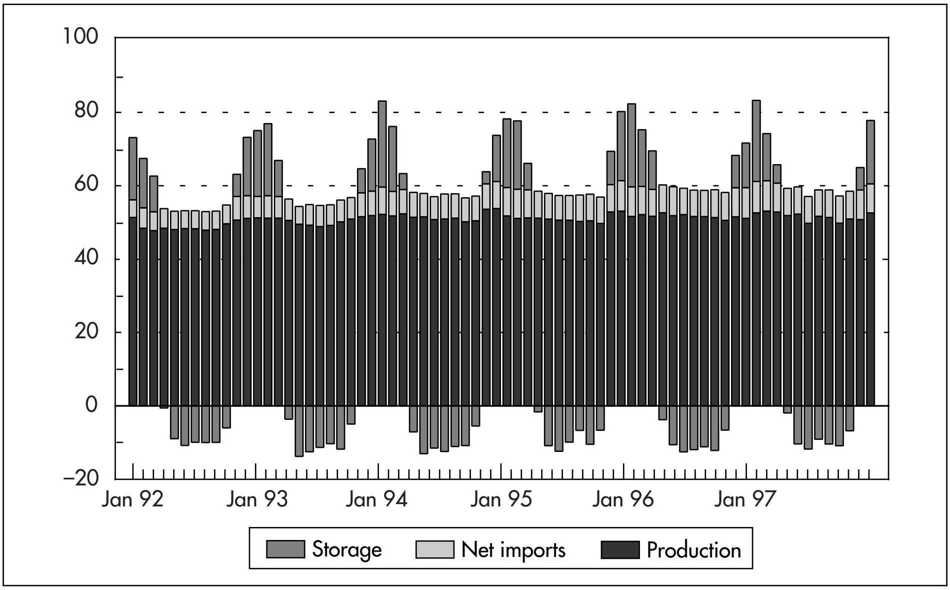

Source: EIA, *Natural Gas Monthly* (DOE), various issues

*Figure A-22*
**US Salt Cavern Cycling, 1991/92 to 1995/96**
(Average number of cycles*)



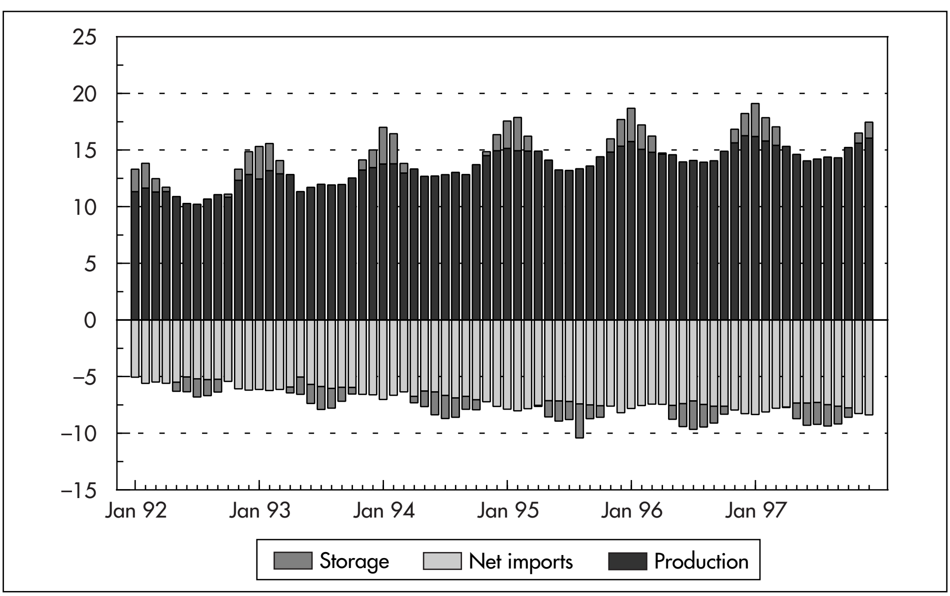

* Full depletion and refill of facility.
Source: EIA, *Natural Gas 1996: Issues and Trends* (DOE, 1996)

*Figure A-23*
**US Gas Supply by Source, 1992 to 1997**
(Bcf/day)




Source: EIA, *Natural Gas Monthly* (DOE), various issues

*Figure A-24*
**Canadian Gas Supply by Source, 1992 to 1997**
(Bcf/day)

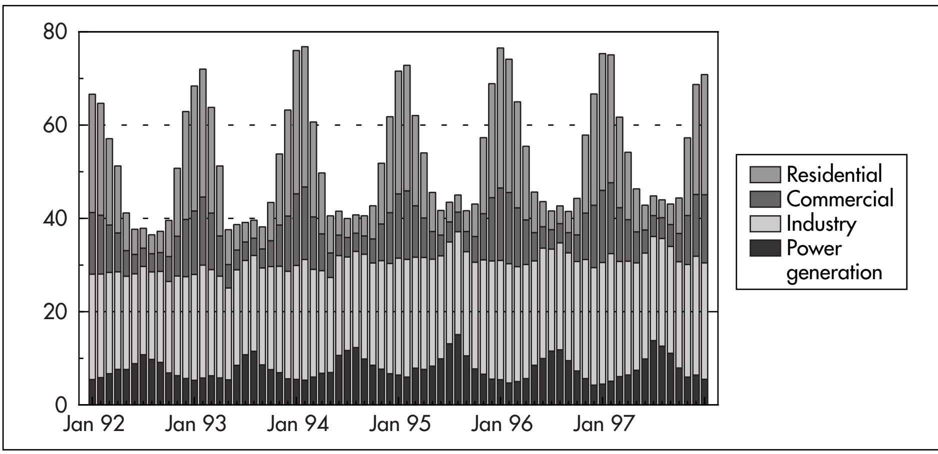



Source: Statistics Canada, *Crude Petroleum and Natural Gas Production* (various issues).

# The Structure of Demand

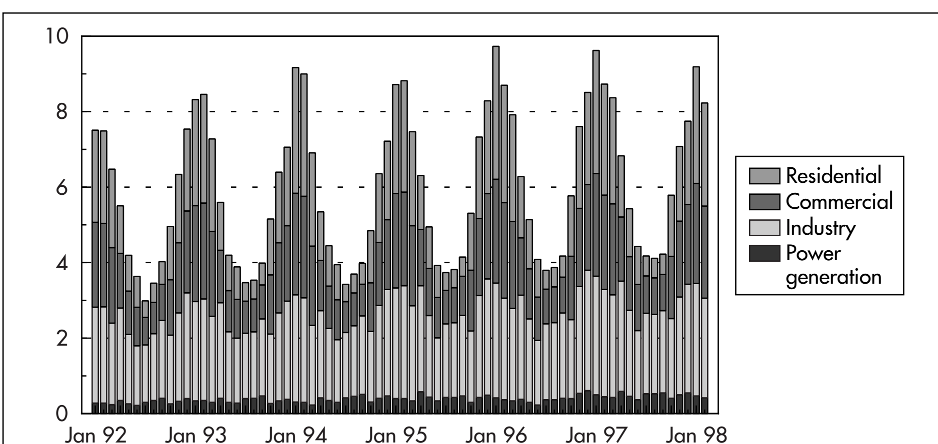
North American gas demand is highly seasonal due to the high levels of gas use for space heating in the residential and, to a slightly lesser extent, the commercial sector (see Figures A-25 and A-26). This seasonality is offset to some extent by reduced gas use in the industrial and power-generation sectors. Higher gas use in the power sector to meet air conditioning demand in summer usually results in a small upturn in total gas use lasting one or two months.

*Figure A-25*
**US Gas Consumption by Sector, 1992 to 1997**
(Bcf/day)




Source: EIA, *Natural Gas Monthly* (DOE), various issues

*Figure A-26*
**Canadian Gas Consumption by Sector, 1992 to February 1998**
(Bcf/day)




Source: Statistics Canada.

## The Role of Interfuel Competition

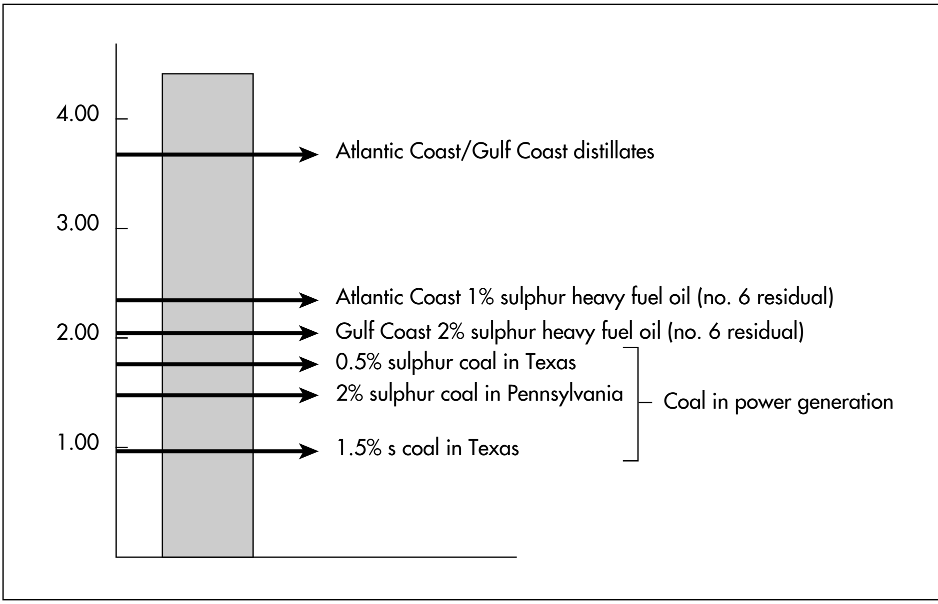
As described in Part I of this report, the market or spot price for gas at any given moment is determined by the marginal consumer and the marginal supplier. For any given location, there can only be one market price. Regional price differentials will reflect the cost and availability of transportation capacity.

In the United States, there is a highly developed capability in manufacturing industry and the power sector for short-term switching between natural gas and other fuels. Fuel-switching behaviour is driven by competition and profit. Companies and utilities will often switch from one fuel to another, even for only a few days, to benefit from a sudden shift in relative fuel prices, although the contractual and technical difficulties of doing this vary. The marginal end-use consumer is almost always a non-captive industrial consumer or power generator which has the option of switching fuel or using a different combustion unit (fired with an alternative fuel) at short notice. Only at peak demand levels would all dual-fired consumers switch out of gas. Total short-run fuel-switching capability is shared more or less equally between the electric utility and industrial sectors, though a much higher share of gas-capable capacity — more than 90% — is multi-fired in the power sector[22]. In addition, there is potential for system-wide fuel switching in the power sector, whereby a coal or oil plant is brought on-line to replace a gas-fired plant. Non-captive customers are invariably supplied with gas under interruptible contracts (either transportation alone or a bundled supply contract with a marketing company).

The existence of such fuel-switching capability means that there is a strong link between gas demand and prices and the prices of oil products and coal. For a given set of competing fuel prices, gas demand will fall as gas prices rise. Figure A-37 indicates the approximate trigger levels of gas prices at which competing fuels are at parity and different types of interruptible loads are liable to be shed assuming a price of US$ 18/barrel for WTI crude oil[23]. For more than half of interruptible customers with dual-firing, heavy fuel oil is the substitute fuel. At most times, therefore, gas prices do not have to rise much above heavy fuel oil prices to choke off enough demand to bring the market back into balance. Total US gas demand susceptible to switching within a gas price range of $2 to $3/Mbtu is thought to amount to around 3 to 4 bcf/day, equivalent to about 5% to 6% of national demand[24]. The bulk of this demand (around 2 to 3 bcf/day) is in the power sector.

22. See IEA, *Gas Security Study* (1995). The latest industry survey data for 1988, cited in that study, show that 39% of companies using gas as their primary fuel were capable of immediately switching to other fuels (DOE/EIA, *Manufacturing Fuel Switching Capability 1988* (1991).
23. Lower crude prices in the first half of 1998 imply that the threshold levels of gas prices to choke off each tranche of demand have been significantly lower.
24. At average 1997 oil prices.

*Figure A-27*
**Indicative Parity Values of Competing Fuels to Natural Gas**
($/Mbtu)




Note: Assumes a WTI crude oil price of US$18/barrel and average 1997 coal prices. Power generation values are adjusted for the different thermal efficiencies of coal and gas-fired generation.
Source: IEA analysis

An analysis of the power-generation market, for which detailed demand and price data are available, reveals the importance of this sector's gas-consumption patterns and the key role that heavy fuel oil and coal prices used in this sector play in determining gas prices across North American markets generally. Natural gas use in power generation follows a pronounced seasonal pattern, peaking in the summer months, when residential demand for gas is very low and demand for electricity is high. This seasonality is strongest in the West South Central (WSC) region, because of higher summer temperatures (see Figure A-28).

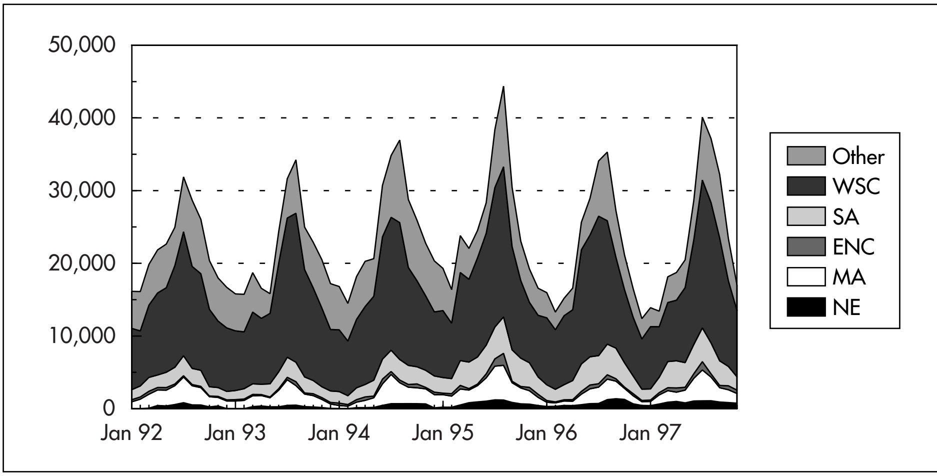
In most regions, gas accounts on an annual basis for less than 10% of total power generation. Gas-fired generation is highest in WSC, where it typically accounts for between 25% and 45% of total generation, and in New England (NE), where gas peaked at over 25% of total generation in September 1996 (see Figure A-29).

The fuel mix in US power generation is determined by a complex set of factors, including the availability of nuclear and hydro power and relative fossil-fuel input prices. In general, however, gas displaces heavy fuel oil under boilers in the summer and is in turn displaced by fuel oil in the winter. Table A-4 details gas-capable multi-fired electric utility generating capacity in the United States by type of plant. Oil/gas dual-fired steam boiler plants account for the bulk of gas-capable multi-fired capacity.

*Figure A-28*

**US Gas-Fired Power Generation, January 1992 to November 1997**

(Billion kWh)




Note: Definitions of regions are as follows:

*West South Central:* Arkansas, Louisiana, Oklahoma and Texas.

*South Atlantic:* Delaware, District of Columbia, Florida, Georgia, Maryland, North Carolina, South Carolina, Virginia and West Virginia.

*East North Central:* Illinois, Indiana, Michigan, Ohio and Wisconsin.

*Middle Atlantic:* New Jersey, New York and Pennsylvania.

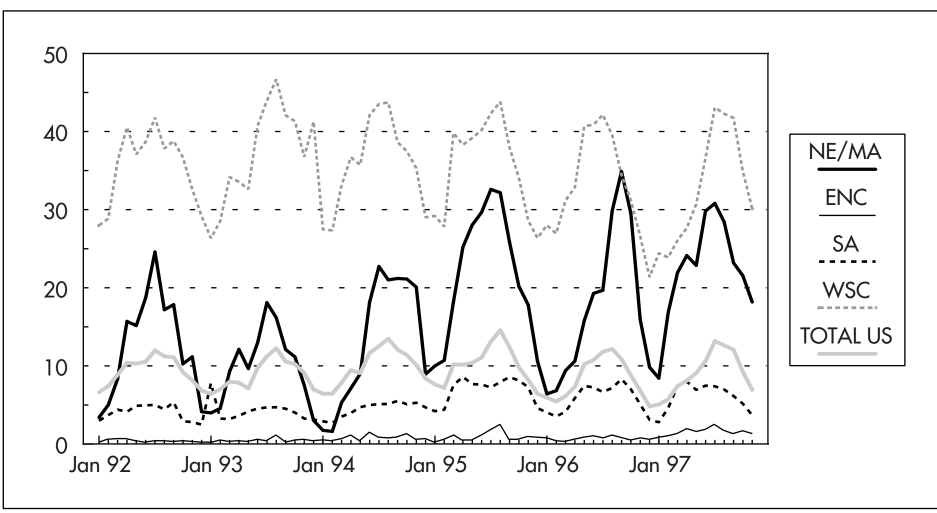
*New England:* Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.

Source: EIA, *Electric Power Monthly* (DOE), various issues

*Figure A-29*

**Share of Gas in US Power Generation, January 1992 to November 1997**

(% of regional total)




Source: EIA, *Electric Power Monthly* (DOE), various issues

*Table A-4*

**Natural Gas-Capable Electric Utility Generating Capacity by Type of Plant**

(At 1 January 1997)

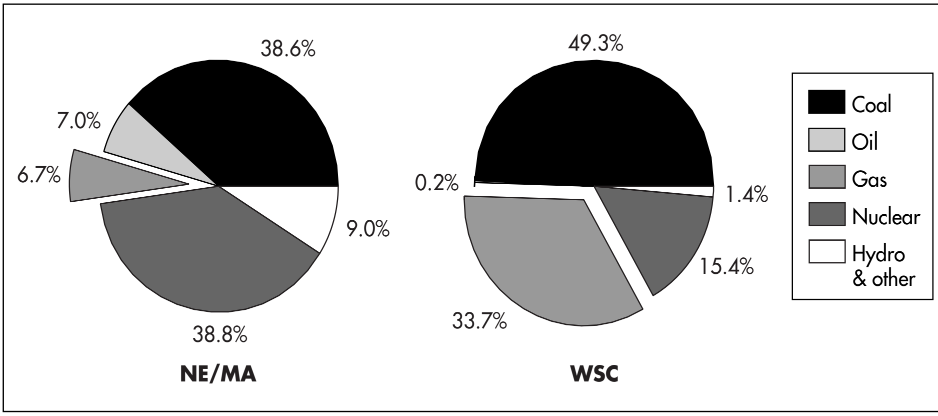
| Type of plant | Net winter capacity (MW) | % of total gas-fired capacity |
|---|---|---|
| Steam | 155 365 | 76.3 |
| *Gas only* | *10 146* | *5.0* |
| *Gas/oil* | *106 971* | *52.5* |
| *Gas/solids* | *37 725* | *18.5* |
| *Gas/solids/oil* | *523* | *0.3* |
| Gas Turbine | 37 739 | 18.5 |
| *Gas only* | *5 745* | *2.8* |
| *Gas/oil* | *31 994* | *15.7* |
| Internal combustion | 2 278 | 1.1 |
| *Gas only* | *59* | *Negligible* |
| *Gas/oil* | *2 219* | *1.1* |
| Combined cycle | 8 206 | 4.0 |
| *Gas only* | *1 671* | *0.8* |
| *Gas/oil* | *6 440* | *3.2* |
| *Gas/solids* | *95* | *Negligible* |
| Total | 203 588 | 100.0 |
| *Gas only* | *17 621* | *8.6* |
| *Gas/oil* | *147 624* | *72.5* |
| *Gas/solids* | *37 820* | *18.6* |
| *Gas/solids/oil* | *523* | *0.3* |

Source: EIA, *Inventory of Power Plants in the United States 1997* (DOE, 1998)

Short-term fuel or plant switching is most pronounced in New England and Middle Atlantic. In the winter, the marginal consumer is typically a power generator or large industrial consumer in these regions, where captive load is at its highest and only limited amounts of gas are available for non-captive users. Gas competes in the East Coast power-generation market primarily with heavy fuel oil in steam boilers for upper intermediate load (base and lower intermediate loads are met largely by nuclear, hydropower and coal)[25]. In the summer, when most switchable power generation and industrial capacity on the East Coast has shifted to gas, the marginal end consumer tends to look to supplies from the south[26]. In that region, gas competes against coal for intermediate and peak-load generation; there is very little oil-fired capacity. Figure A-30 details the fuel mix in these regions for 1996.

25. The alternative fuel in single turbine and combined cycle turbine plant, which together account for almost 19% of gas-capable capacity, is usually distillate.
26. See R. Huitric and John Crowley, *Inter-Energy Competition and Natural Gas Prices in the United States* (Energy Studies Review, No.2-3, 1990) for discussion of this phenomenum.

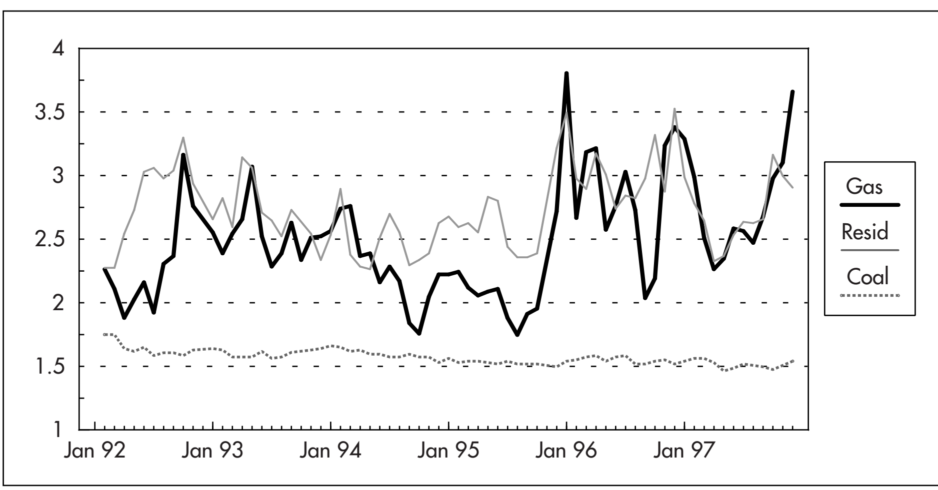
*Figure A-30*
**Net Power Generation by Fuel in New England/Middle Atlantic and West South Central, 1996**




Note: Gas slice is exploded
Source: EIA, *Electric Power Monthly* (DOE), various issues

Environmental regulations are not thought to have a strong influence over short-term fuel switching decisions[27], although local regulations determine the sulphur

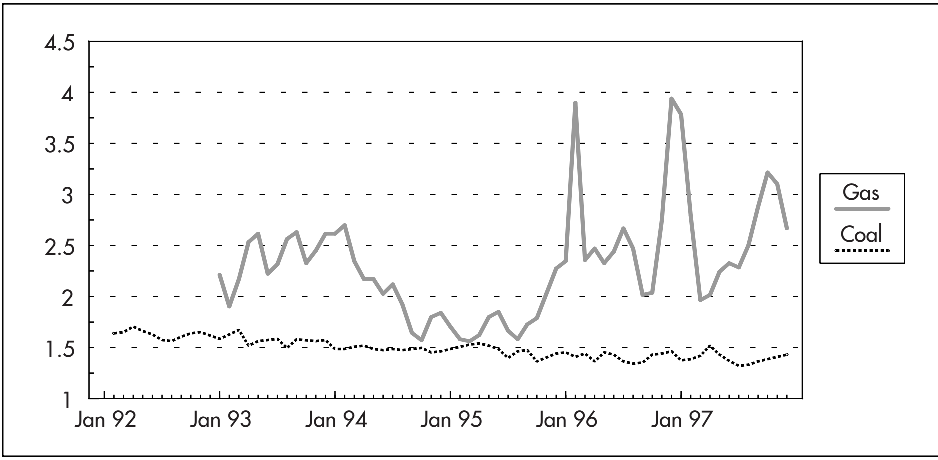
*Figure A-31*
**Spot Fuel Costs to Power Generators in Middle Atlantic, January 1992 to December 1997**
(Adjusted for thermal efficiency, cents/kWh)




Note: Residual fuel is 1% sulphur no. 6 oil; coal is the average of all purchases.
Source: IEA, based on EIA/DOE data from *Electric Power Monthly*.

27. See GRI, *Implications of Electric Utility Fuel Switching* (1993)

*Figure A-32*
**Spot Fuel Costs to Power Generators in West South Central, January 1992 to December 1997**
(Adjusted for thermal efficiency, cents/kWh)




Note: Coal is the average of all purchases.
Source: IEA, based on EIA/DOE data from *Electric Power Monthly*.

content and therefore the price of heavy fuel oil. The tighter the pollution controls in any given area, the lower the sulphur content allowed and therefore the higher the gas price can rise before reaching parity with the fuel-oil price.

Allowing for differences in thermal efficiency, it is possible to compare the variable cost of gas, heavy fuel oil and coal in power generation per kWh generated[28]. This analysis shows that, in the winter, the price of low sulphur heavy fuel effectively provides a ceiling for gas prices in the East Coast power-generation market. Figure A-31 shows that over the period 1992-1997 gas prices to power plants in the Middle Atlantic area have only rarely risen above fuel-oil prices. Generally during the winter gas prices have followed movements in fuel-oil prices without rising above them.

In the summer, when the marginal consumer is typically to be found in the south, the spot price of coal in that region provides a floor for gas prices (see Figure A-32).

## Regional Price Differentials: Transportation Costs and Constraints

As the above analysis demonstrates, the marginal consumer at any given moment plays the key role in setting gas prices generally in the North American market.

28. In this analysis, average station thermal efficiencies of 33% for gas and heavy fuel oil and 31% for coal were assumed.

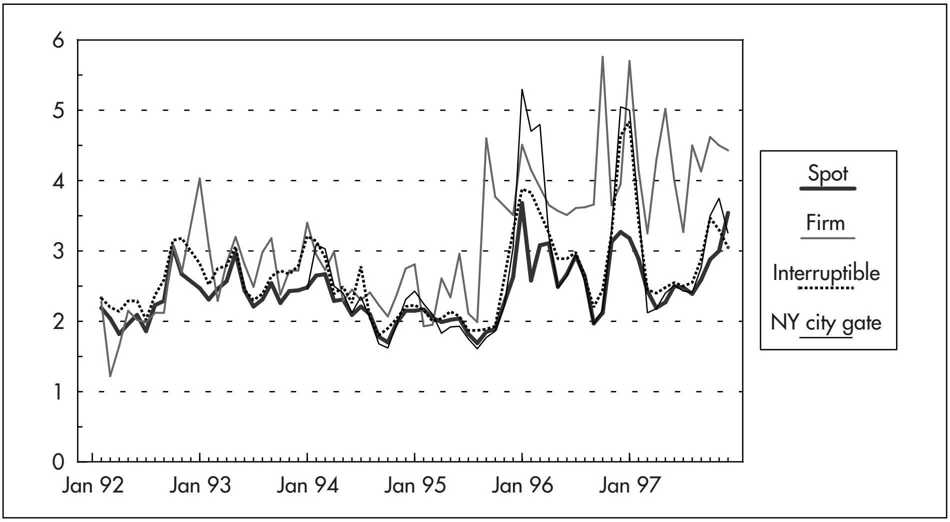
The gas price that the marginal (interruptible) consumer — often a power generator — is prepared to pay is determined by competing fuel prices. Regional price differences — between delivery points — reflect transportation costs when there are no pipeline capacity constraints. Figures A-33 and A-34 show recent trends in spot-gas prices in West South Central and Middle Atlantic for delivery to the major hub and to power plants in each region. At almost all times since 1992/3, spot prices have moved in parallel, the small differentials between them at most times being explained by marginal differences in transportation costs. In both areas, the differentials between delivery to the delivery hubs (Henry Hub and New York city gate) and power plants briefly broke out of their normal tight ranges in the winter of 1996/7 because of a surge in captive market demand (due to cold weather) and pipeline capacity constraints.

For as long as there is spare pipeline capacity within the North American gas network, regional price differentials will reflect the actual cost of moving gas between regional delivery points. At times of lowest demand (spring and early autumn), the cost of transportation is set by the price of released capacity on the FERC-regulated electronic bulletin board market in the United States or the unregulated Canadian secondary market. Active arbitraging by gas traders ensures that spot-price differentials never move greatly out of line with transportation costs: parallel trading of gas and pipeline capacity ensures that regional differentials reflect the value of available capacity. At such times, regional spot-price differentials are low and fairly predictable (see Figure A-35). The summer differential between Henry Hub and New York city gate prices has been around 20 to 25 cents/Mbtu in recent years. This reflects the lower market price of capacity on the secondary-release market (compared to the regulated cost of transportation capacity of about 70 cents/Mbtu) and the variable cost of transportation (mainly of pipeline fuel).

The above analysis provides an incomplete explanation of regional price differentials, which have at times fluctuated wildly and reached extremely high levels, although usually only for brief periods. These differential "blow-outs" — or regional market disconnects — are caused by periodic and sometimes prolonged pipeline bottlenecks. In these conditions, the marginal consumer at any given time wherever he is located can no longer affect the demand/supply balance and price in other regions. Once capacity between two regional markets attains full utilisation and bottlenecks occur, demand and supply *within* each market, rather then *between* each market, determine spot prices. The implicit value of pipeline capacity between two markets may then soar to levels well above the long-term cost of firm capacity. Secondary pipeline rates in the US market are capped at the regulated rate, although gray-market transactions can reflect the true value of pipeline capacity at such times.

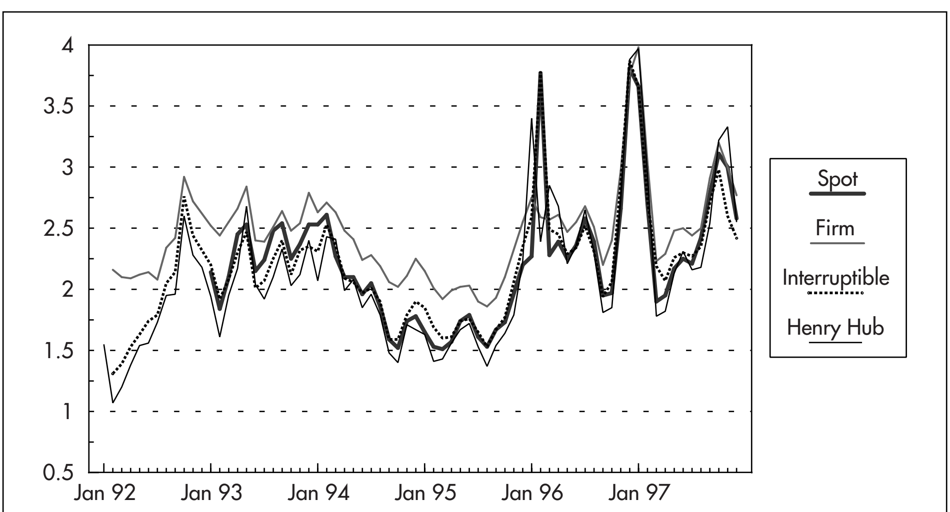
The emergence of these disconnects greatly increases basis risk and enhances the attractiveness of regional futures markets. They also reveal the degree of pipeline bottlenecks and provide signals for construction of new capacity or expansion of existing lines.

*Figure A-33*
**Gas Prices to Power Generation in Middle Atlantic, January 1992 to December 1997**
($/Mbtu)



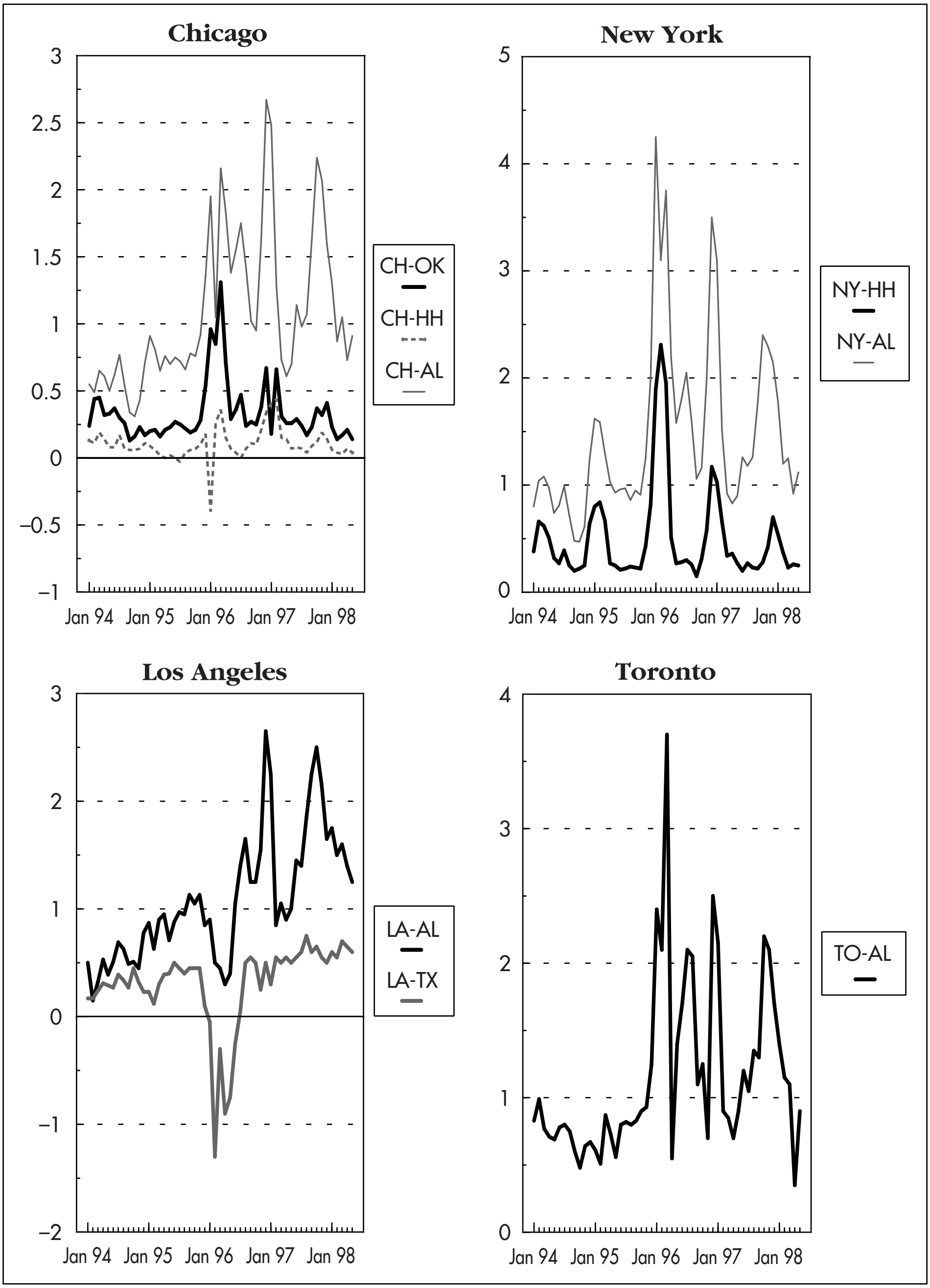

Source: Prices to power generation: EIA, *Electric Power Monthly* (DOE), various issues; New York city gate prices: *BTU Weekly*, various issues.

*Figure A-34*
**Gas Prices to Power Generation in West South Central, January 1992 to December 1997**
($/Mbtu)




Source: Prices to power generation: EIA, *Electric Power Monthly* (DOE), various issues; Henry Hub prices: *BTU Weekly*, various issues.

*Figure A-35*
**North American Spot Gas Price Differentials, January 1994 to May 1998**
(City gate less delivered to pipeline, $/Mbtu)

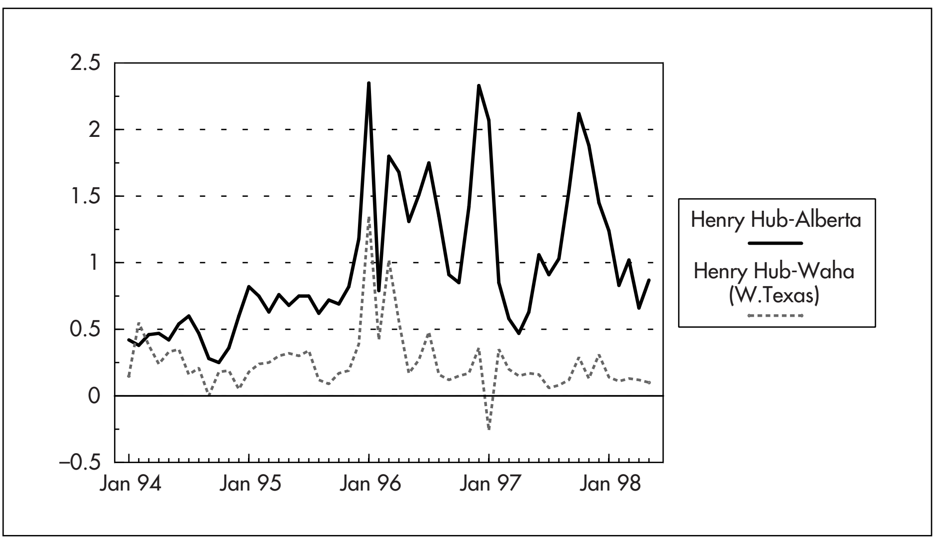



Note: HH=Henry Hub; AL=Alberta (AECO); OK=Oklahoma (NGPL pipeline); TX=West Texas (El Paso pipeline)
Sources: *World Gas Intelligence and BTU Weekly*, various issues.

This periodic "regionalisation" of the North American gas market has become more frequent and widespread in the last two to three years as deliverability from some regions during the heating season has fallen short of peak demand due to unanticipated cold winters. Spot gas prices in the East have at times diverged sharply from spot prices in the Western United States and Canada. This disconnect has been caused by a bottleneck in West-East pipeline capacity, resulting in a buildup of gas supplies from the three supply regions to Western markets (Western Canada, the Rocky Mountains and the San Juan Basin). For example, spot price differentials between Alberta and New York jumped from under $1/Mbtu to over $4/Mbtu in February 1996 (see Figure A-35). The Alberta/Toronto spread also billowed from under $1/Mbtu to over $3.50/Mbtu. This pattern was repeated in January 1997.

The price differential between Henry Hub and Alberta has also tended to increase over the past two years, from an average of around 50 cents in 1994 to over $3/Mbtu in late 1997. The differential between the Waha Hub in West Texas and Henry Hub which is normally very small — increased to over $1/Mbtu in winter 1995/6 due to the lack of available pipeline capacity (see Figure A-36).

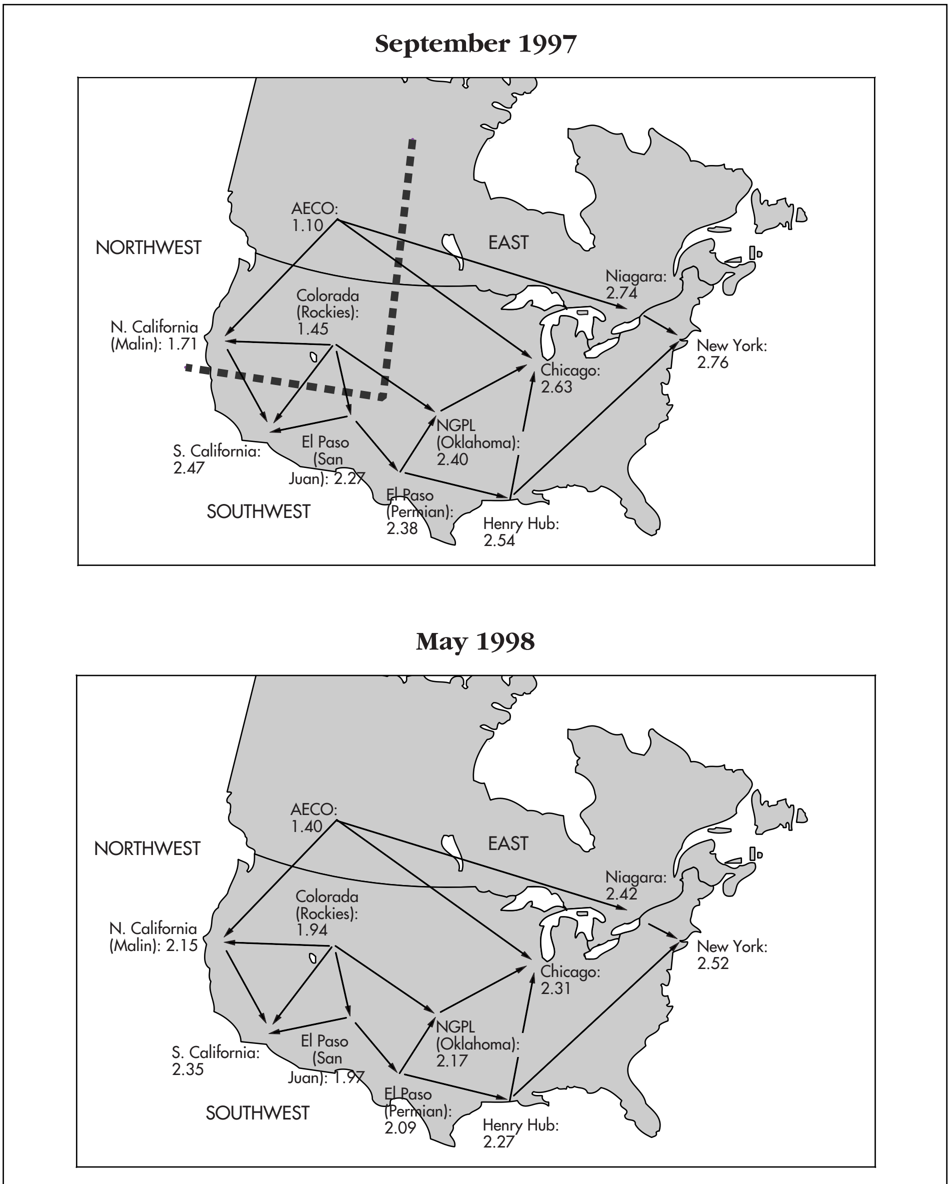
*Figure A-36*
**Henry Hub Spot Gas Price Differentials, January 1994 to May 1998**
($/Mbtu)




Source: *BTU Weekly*, various issues.

The West/East disconnect that emerged in the mid-1990s has diminished since 1997, largely due to stronger demand in western markets and unseasonably mild weather in the Northeast over the 1997/8 winter (see Figure A-37). In late 1997, there was a continuing disconnect between the Northeast/Southeast and the Northwest producing regions, reflecting a lack of capacity between West Canada and the Northeast and between the Rockies and the mid-continent. At that time, prices in the Southern half of the West were closely connected to prices in the Southeast. By April 1998, regional price differentials had narrowed considerably with weaker demand and fewer pipeline capacity constraints across North America.

*Figure A-37*
**Spot Gas Prices in North American Regional Markets**
($/Mbtu)




Source: IEA, based on *BTU Weekly data*.

When regional markets disconnect, the short-term balance of supply and demand within each market determines price. At times of peak demand, the marginal consumer may be an interruptible customer with distillate as back-up fuel. That consumer may be a combined-cycle gas-turbine power plant or an industrial boiler or turbine. Distillate prices are usually much higher than heavy fuel oil prices, so that gas prices would have to rise to much higher levels to choke off this interruptible load (see Figure A-27).

Spot prices for delivery one day ahead can also rise to very high levels even when supplies to interruptible customers using distillate have been cut. This reflects the severe financial penalties (up to $25/Mbtu) that pipeline companies may levy on shippers who do not balance their loads. For technical and contractual reasons, it may be difficult for a shipper, which is already fully using its storage flexibility, to interrupt supplies to enough customers at very short notice to bring load back into balance with available supply.

## The Role of Storage, Weather and Expectations

The analysis of price determination has been simplified in order to demonstrate the key role played by the marginal consumer in determining the single market price, to which prices across the country are related through transportation costs. In practice, the marginal consumer in the wholesale or bulk market, be it an LDC, end user or marketer, may in fact be taking delivery of gas for injecting into storage. Such a buyer is a non-captive consumer to the extent that it may vary the timing of his gas purchase decisions according to its expectations of short term price movements: if it judges that the spot price will fall, it may delay its purchase of gas for injecting into storage. Similarly, the marginal supplier of gas to the market may be selling gas out of storage, so that short-term supply is not dependent on wellhead deliverability. Again, a seller of gas from storage may hold back selling if it judges that price will rise in the near term.

The size of storage capacity and peak deliverability in North America means that expectations about future price and peak winter demand levels can have a considerable impact on spot prices, through their effect on short-term gas purchase and selling decisions. This influence appears to have increased in recent years with the increased transparency of spot gas markets and the availability of timely estimates of changes in storage levels on a weekly basis. The value of high-deliverability salt-cavern storage — which can be filled and emptied in a month or two — has increased because of flexibility in taking advantage of intertemporal and interregional price movements[29]. Of new storage projects under construction or planned, salt caverns account for the majority of withdrawal capacity if only a small proportion of working gas storage capacity[30].

29. See John H. Herbert, *Improving Competitive Position with Natural Gas Storage* (Public Utilities Fortnightly, 15 October 1995); and EIA/DOE, *The Value of Natural Gas Storage in Today's Natural Gas Industry* (1995).
30. See EIA/DOE, *Natural Gas: Issues and Trends 1996* (1996)

Weather — or rather expectations or forecasts of weather — is a key factor in decisions on stocking or destocking. Actual demand levels and expectations of demand determine prices at any given time. North American gas markets, in this respect, have become similar to spot oil markets, where prices fluctuate sharply from day to day and even hour to hour on news reports or the release of information deemed to be relevant to the near-term outlook for supply or demand.

## LONG-RUN PRICE DETERMINATION

Day-to-day spot gas price movements reflect short-term shifts in demand, due to changes in the weather, gas market values in competition with other fuels or expectations of future demand and supply factors, given that supply capacity is largely fixed in the short run. In the long run, competitive gas prices in a freely functioning market should oscillate around long-run marginal costs for a given level of demand.

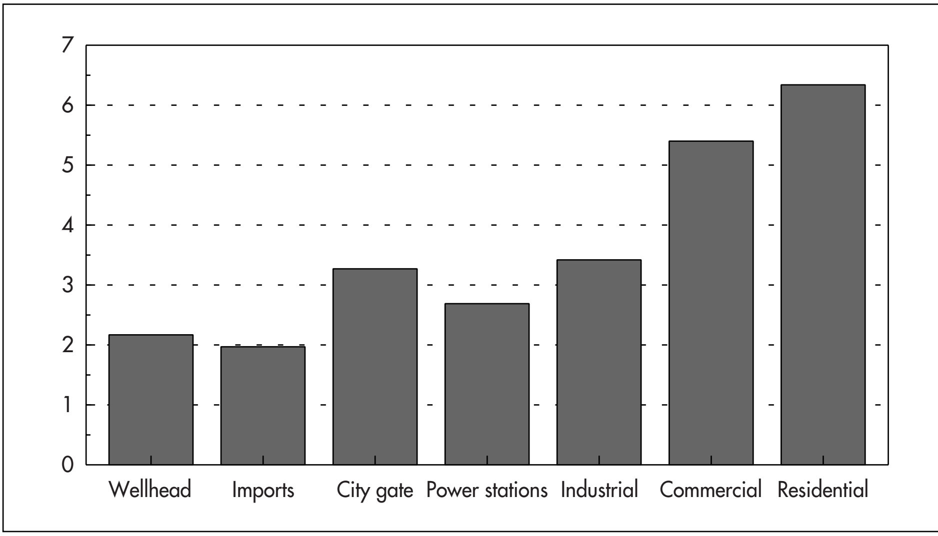
Geology, as in any gas market, is the key factor in determining the long-run marginal cost of supply of gas and, therefore, prices. Wellhead prices have tended to be low in the United States and Canada compared to other parts of the world, in large part due to the accessibility of low-cost onshore reserves. Production from offshore fields has increased in recent years, but lower development costs have helped to keep overall production costs down. Average reserve additions per exploratory well drilled in the United States have risen from around 9 bcf in the mid-1980s to nearly 20 bcf by the mid-1990s[31], reflecting the larger share of deep-water, high-productivity offshore wells. However, there has been significant increase in reserve additions for onshore wells outside Alaska and Hawaii. There is thought to be remaining potential for lowering production costs in North America, though technology and organisation-driven efficiency improvements may be offset by the increasing costs associated with drilling in more remote and deeper water locations or with the increasingly smaller onshore traps.

## STRUCTURE OF AND LONG-TERM TRENDS IN END-USER PRICES

Differences in the final prices to end users reflect differences in the cost of the elements of the final delivery of gas services. A comparison of the different pre-tax prices paid by different end-user categories in the United States based on official DOE/EIA data gives an indication of the relative importance of the various cost elements, including the gas itself, interstate transmission and local delivery (see Figure A-38).

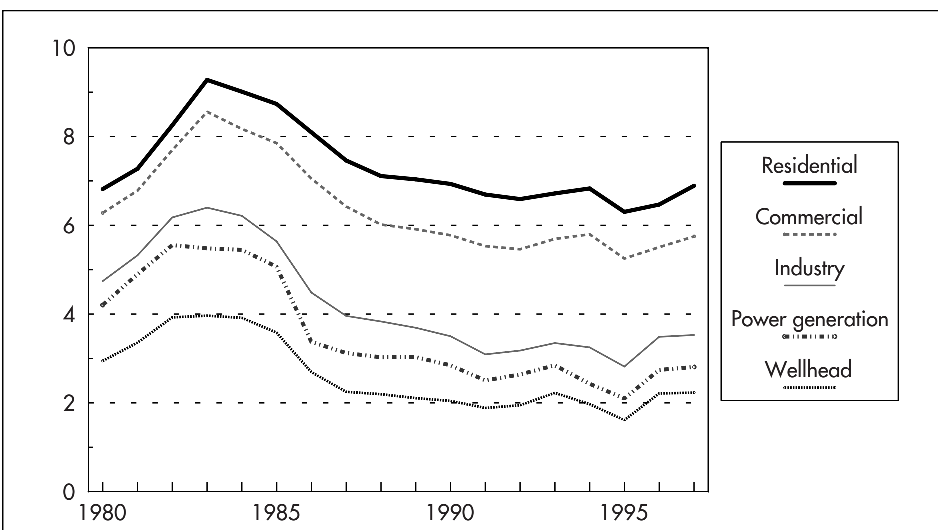
31. See IEA, *The Gas Security Study* (1995)

*Figure A-38*
**Average Natural Gas Prices in the United States, 1996**
($/Mbtu, excluding sales taxes)




Source: EIA/DOE, *Natural Gas Annual 1996* (1997)
Note: Industrial and commercial prices are for LDCs direct (on-system) sales only.

*Figure A-39*
**Real Average Selling Prices for Natural Gas in the United States, 1980 to 1997**
(1997 prices, $/Mbtu, excluding sales taxes)




Source: EIA/DOE, *Natural Gas Annual 1996* (1997); *Natural Gas Monthly*
Note: Prices deflated using GDP deflator.

Average prices for the United States show that the additional average cost of interstate transportation and storage, over and above average gas supply costs (at the wellhead and border) of $2/Mbtu, amounted to 70 cents/Mbtu for power stations and $1.25/Mbtu for LDCs' delivered gas costs at the citygate. Average gross LDC margins (i.e. the mark-up over and above citygate costs) range from around $1.40/Mbtu for industrial end-users to $4.30/Mbtu for residential customers[32]. DOE/EIA data does not permit a detailed breakdown of the cost of storage within transportation, nor net margins at different stages of the gas chain. However, pipeline charges are known to account for the bulk of interstate transportation costs and local distribution costs.

Figure A-39 shows the long-term trend in real pre-tax end-user selling prices. Prices peaked in the early 1980s and fell steadily thereafter, rebounding slightly in 1996 and 1997. The Industrial and power sectors have witnessed the biggest falls in prices, reflecting to a large extent the shift to straight fixed variable pricing of pipeline capacity which benefited customers with the highest load factors. The fall in end-user prices reflects lower wellhead prices as well as lower unit transportation costs.

32. It should be noted that city-gate costs reflect the average load factor of LDC sales; the true city-gate cost of gas for sale to low load factor residential customers will therefore be higher than for higher load factor industrial and commercial sales.

B

# GREAT BRITAIN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1

# SUMMARY

- Far-reaching and rapid reforms implemented since the late 1980s have revolutionised the British gas business. Initial legislative moves to promote open access and competition in supply to large end users were followed by a series of measures to speed up the emergence of a fully competitive market. These included contractual and pricing restrictions on the monopoly gas company, British Gas (demerged in 1997), obligations on BG to release previously contracted supplies to competitors and the extension of retail competition to all consumers, including households, by mid-1998.

- Gas commodity prices are unregulated. However, some controls will be kept on the prices that Centrica (the former marketing arm of BG) is allowed to charge to residential customers as long as that company remains the dominant supplier. Network charges by BG Transco, the monopoly transmission and distribution pipeline company, continue to be regulated on a rate-of-return basis with prices capped over a defined period.

- The Network Code, implemented in 1996, constitutes the contractual regime for the commercial and operational aspects of gas transportation in Britain. It lays down the terms and conditions of access to Transco's network by licenced shippers, including new daily load-balancing obligations.

- Most gas is supplied to the beach from offshore fields under long-term depletion contracts, mostly held by Centrica. Recent beach deals have been for shorter periods, usually less than five years. Many producers are now selling more gas on the spot market. The introduction of daily balancing requirements on shippers has led to a considerable volume of trade in day-ahead and within-day gas. Almost a fifth of delivered gas is now thought to be traded on the over-the-counter spot market. Trading of the International Petroleum Exchange futures contract, launched in 1997, has also increased. Spot and futures prices are increasingly used for indexing purposes in medium- and long-term contracts.

- Price levels are driven in the short run primarily by the weather. For historical reasons, short-term fluctuations in demand are met mainly by production swing. Interruption of supplies to customers with dual-firing is increasingly used by shippers to balance peak load. The lack of storage capacity in Britain means that prices are extremely volatile. At present, interfuel competition plays virtually no part in short-term price setting because gas prices are too low to stimulate switching out of gas and all large consumers with dual-firing capability are already using gas. An effective floor of around 9p/therm ($1.50/Mbtu) appears to be set by producers' willingness to shut in production at lower prices.

- The imminent commissioning of the UK-Continent Interconnector appears to have established a floor for the base price in new term contracts, equivalent to the netback market value to the Bacton terminal in Britain from current sales in European markets.

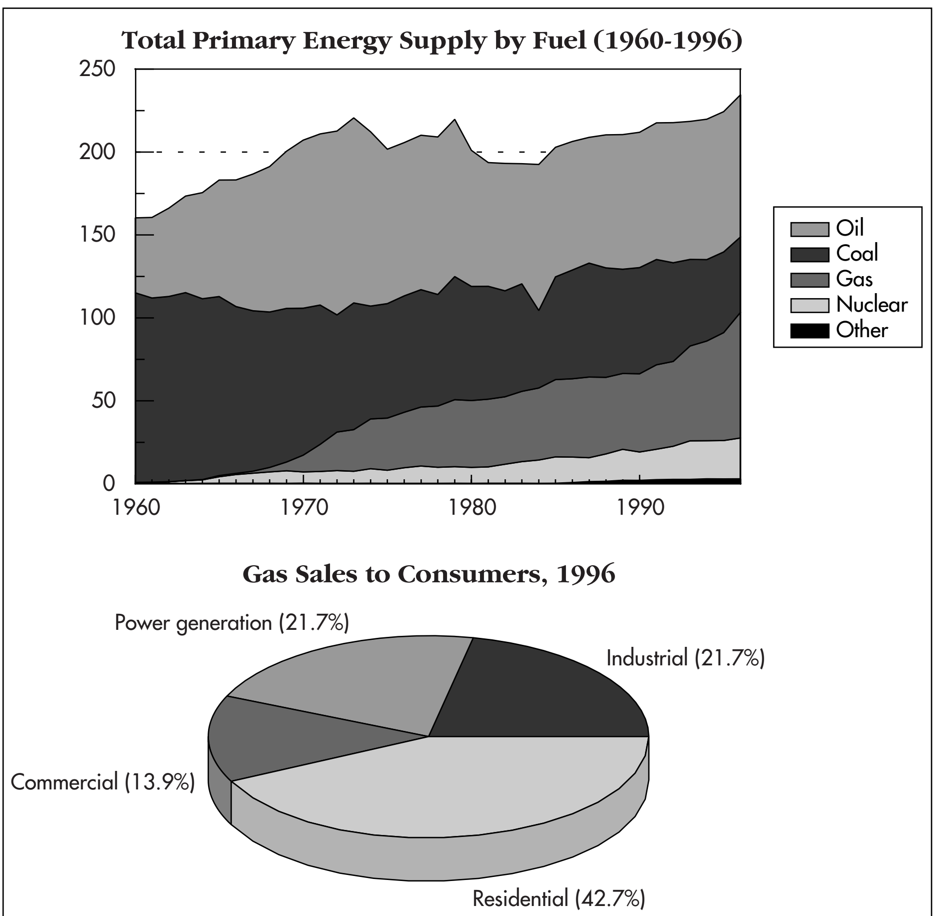
# 2

# INTRODUCTION

## MARKET OVERVIEW

The United Kingdom has the largest national natural gas market in Europe, and the third largest in the world (after the United States and the Russian Federation). Gas accounts for around 29% of total primary energy supply. Gas demand has increased rapidly in recent years, largely due to the commissioning of a number of gas-fired combined-cycle gas-turbine (CCGT) power stations since 1991. The residential sector remains the largest single user of gas. Figure B-1 shows the importance of gas in the UK energy mix and the sectoral shares in gas consumption.

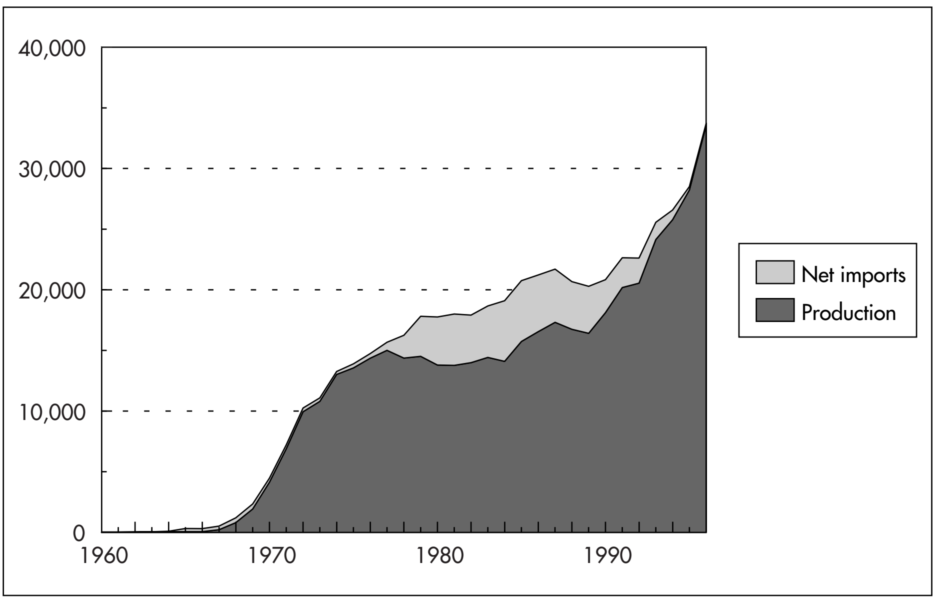
*Figure B-1*
**UK Natural Gas Supply and Demand**




Source: IEA, *Energy Balances of IEA Countries* (OECD)

Gas is supplied mostly from UK offshore fields in the North Sea, the majority of which are located in the Southern Basin. Onshore production accounts for less than 0.5% of total supply. A small proportion of UK needs (2% in 1996) is provided by Norway from that country's share of the Frigg field (see Figure B-2). At its peak in 1984, the Frigg field provided 27% of total UK gas use. The United Kingdom also exports a slightly smaller volume of gas to the Netherlands. These exports have come from the Markham field since 1992, and from the Windermere field since 1997. Exports will increase with the commissioning of the UK-Continent Interconnector in 1998.

*Figure B-2*
**UK Natural Gas Production and Net Imports, 1960 to 1996**
(Million therms)




Source: DTI, *Digest of UK Energy Statistics* (1997).

At present, public gas supply in the United Kingdom is limited to Great Britain (England, Scotland and Wales). A pipeline to Northern Ireland was completed in 1996. The primary market is the Ballymumford power station, but the line is being extended to serve industrial, commercial and residential markets.

## INDUSTRY STRUCTURE AND REGULATORY RESPONSIBILITY

UK gas comes from over 80 fields in the North Sea, 6 fields in the Irish Sea and 13 onshore fields (see Figure B-3). Offshore production is brought ashore at nine terminals, the largest of which are located at St Fergus in Scotland and Bacton on

*Figure B-3*
**UK Gas Pipeline Network**


Source: IEA, *Natural Gas Information* 1997 (OECD, 1998) the East Midlands coast. There are almost 60 oil and gas companies involved in gas production, including Centrica (formerly part of British Gas), all the major international oil companies and independents.

The structure of the downstream gas industry has changed radically since the late 1980s. BG plc (formerly part of British Gas) has retained its near monopoly over national and regional transmission and local distribution through its subsidiary Transco: it owns and operates virtually all distribution networks and the entire transmission network. The one exception is a line owned by PowerGen, which links the Theddlethorpe terminal on the east coast to two CCGT power stations at Killingholme. A 9 billion-cubic-metre-per-year (bcm/year) interconnector between the west coast of Scotland and Ireland, which is owned by the Irish Gas Board (BGE), was commissioned in 1998. The United Kingdom-Continent 20 bcm/year interconnector, also under construction, is owned by a consortium of BG plc[33] (40%); BP, Conoco, Elf Aquitaine, Gazprom (10% each); National Power, Distrigaz, Ruhrgas and Amerada Hess (5% each). Scottish-Hydro Electric is planning a short line linking the St Fergus terminal to its Peterhead gas-fired steam-turbine power station. BG Transco and three companies that operate very small local networks are the only licensed public gas transporters. All storage facilities — the offshore Rough depleted field, a complex of salt caverns at Hornsea and five LNG terminals — are owned and operated by BG Storage, a subsidiary of BG plc.

Gas wholesaling and retailing is carried out by a number of different companies. British Gas Trading (BGT), a subsidiary of Centrica which retains the right to trade under the name British Gas in Great Britain, remains the largest single retailer. It had a legal monopoly of sales to small customers under 2 500 therms per year until 1996. In total, BGT supplied around 65% of the total British market in 1997. Its monopoly of small consumers was removed in stages from 1996. By the end of May 1998, the entire residential market was opened to competition. There are currently over 70 companies licensed to retail gas to customers in the industrial and commercial markets over 2 500 therms per year. By the end of 1997, 21 companies, including some of the existing marketers to the commercial/industrial market, had obtained licenses to market gas to residential customers in all or part of Britain. These companies include subsidiaries of oil and gas producers, regional electricity suppliers, integrated electricity companies and independent energy marketing groups. Most marketers are licensed shippers of gas through Transco's network.

The Office of Gas Regulation (Ofgas), headed by the Director General for Gas Supply (the regulator), is responsible for regulating the gas industry. Its main functions are to monitor the activities of British Gas as a public gas supplier and to enforce compliance with the requirements of the 1986 and 1995 Gas Acts and subsequent amendments. Ofgas is empowered under the Act to issue licences to companies for public gas transportation, shipping of gas through the public system and supply of gas to end-users (see next section). The Act also empowers the regulator to make a reference to the Monopolies and Mergers Commission requiring it to report on any

33. BG plc has leased its capacity to British Gas Trading, a subsidiary of Centrica.

matter related to the conditions of a particular licence. Companies can appeal against an Ofgas decision. The regulator is obliged to make licence modifications where the MMC finds that the licence operates against the public interest, taking into account the modifications suggested in the MMC report. An outright Ofgas rejection of an MMC decision can lead to judicial review. The Government plans to create a single energy regulator, by merging Ofgas with the electricity regulatory body, Offer.

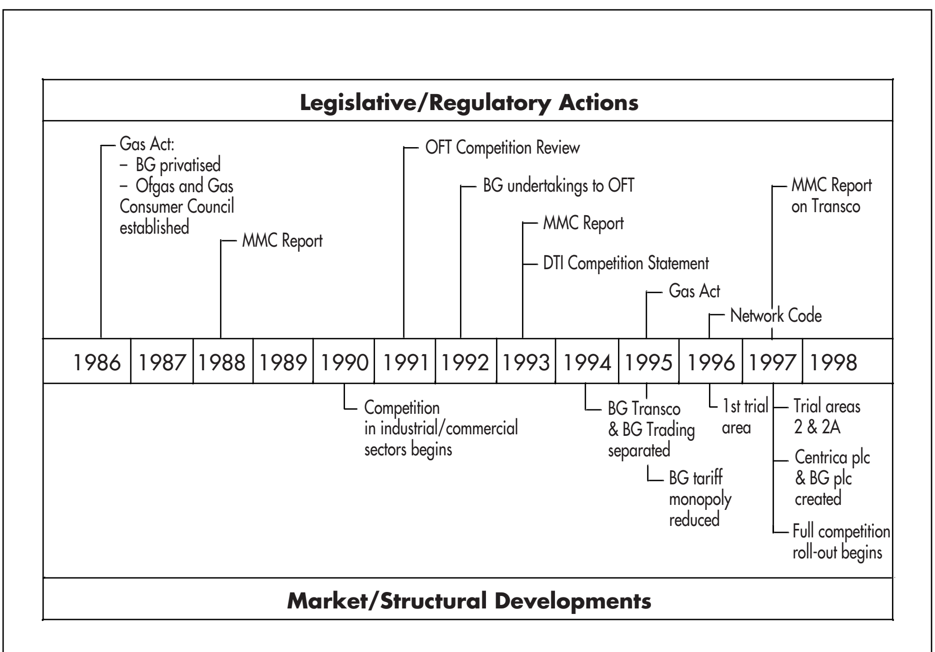
3

# INDUSTRY RESTRUCTURING AND REGULATORY REFORM

## EARLY LEGISLATIVE REFORMS

The foundations for the liberalisation of the British gas industry were laid in 1982 with the Oil and Gas (Enterprise) Act, though competition only started to develop in response to regulatory pressure in the late 1980s (see Figure B-4). The 1982 Act removed the statutory right of first refusal held by British Gas on purchases of gas from offshore and onshore producers for national transmission and distribution. It also allowed for third-party access to BG's pipelines. The 1986 Gas Act provided for the privatisation of BG and the creation of Ofgas and the Gas Consumers Council. The Act also explicitly granted large consumers of more than 25 000 therms/year — the "contract market"— the right to buy their gas from suppliers other than BG. It strengthened the provisions for third-party access to the BG network. BG was granted a 25-year authorisation as a public gas supplier, giving the company a monopoly in the market under 25 000 therms/year. BG's statutory obligation to supply customers in the monopoly tariff market located within 25 yards of an existing public gas line and to meet all reasonable economic requests to supply contract customers was continued.

*Figure B-4*
**Development of Competition in the British Gas Market**



These reforms, intended to promote a limited degree of competition in the supply of gas to large end users, did not provide for any change in the way gas was sold by offshore producers at the beach or by BG to large consumers. Producers were unwilling to supply large end users direct at lower prices so long as BG was willing to buy gas at a netback price. So, BG remained the *de facto* monopsony buyer of North Sea supplies and continued to negotiate prices and other terms of sales to large consumers on the basis of individually negotiated contracts. BG continued to set prices for consumers in the monopoly tariff market according to published tariffs. The level of these tariffs was determined by the Retail Price Index (RPI) - X + Y formula, which provided for gradual reductions in real non-gas costs (X) and full pass-through of gas purchase costs (Y).

## REGULATORY PUSH TO PROMOTE COMPETITION IN THE "CONTRACT MARKET"

The failure of these initial legislative moves to promote any significant degree of competition, together with pressure from new gas suppliers and consumers — notably potential investors in co-generation projects who objected to BG's policy of pricing gas on the basis of gas oil prices — resulted in a Monopolies and Mergers Commission inquiry in 1988. The MMC's recommendations and those of a subsequent inquiry by the Office of Fair Trading in 1991 led Ofgas to undertake a series of actions aimed at lowering market entry barriers for new suppliers and reducing BG's market share to 40% of the competitive market by 1995 — an undertaking adopted by BG after the OFT inquiry:

- At Ofgas's request, BG undertook in 1988 to contract for no more than of 90% of the gas production from any given new field on the UK Continental Shelf over the period June 1989 to May 1991, thereby obliging producers to sell at least 10% to an independent supplier or end user.

- In 1992, Ofgas obtained an undertaking from BG to release gas under long-term contract to other suppliers to the contract market: 500 million therms from 1992/3 to 1994/5 and a further 250 million therms in 1995/6. More than thirty companies received gas under this plan.

- BG also undertook to do away with individually negotiated contracts in the competitive market and replace them with contracts based on published, non-discriminatory tariffs. The company agreed to publish indicative transportation tariffs.

- BG committed itself to unbundle the accounts of its gas trading and pipeline activities and establish "Chinese walls" to ensure non-discriminatory treatment of third-party network users. BG accepted to publish transparent transportation and storage charges.

- In 1992, Ofgas reduced the threshold for BG's monopoly tariff market from 25 000 to 2 500 therms/year.

These actions led to a rapid increase in sales to large consumers from independent marketers. BG's share of the commercial/industrial market fell to around 75% by the end of 1992 and to under 25% by the end of 1995. In response, Ofgas lifted the requirement on BG to offer supplies under published tariffs in 1995.

## INTRODUCTION OF FULL RETAIL COMPETITION: THE 1995 GAS ACT

By the late 1980s, the potential emerged for separating energy networks from trading and supply activities, brought about by rapid advances in information technology. The privatisation of the electricity industry in 1990 was accompanied by the establishment of a competitive power pool and a timetable for the gradual removal of monopoly rights to supply power to end users, with full liberalisation planned for 1998. In 1993, following the completion of two reports by the MMC which advocated the removal of BG's tariff market monopoly (see below), the Government released a policy statement supporting the introduction of full retail competition in the gas industry. The emergence of surplus supplies of gas from the North Sea and the resulting downward pressure on spot prices after 1994 gave further encouragement to extending competition, by making gas available for new suppliers and offsetting the impact of removing cross-subsidies on some categories of small consumers.

The 1995 Gas Act set out a timetable for introducing competition in the remaining monopoly tariff market, consisting of 19 million small residential consumers, thus completing the transition to a fully competitive gas market, also by 1998. This scale of opening of the retail market was unprecedented. It dwarfed the tentative pilot programmes that have been set up in the United States in recent years (see Part 2-A). To pave the way for this transition, the 1995 Gas Act established a new licensing system for gas transportation system operators (essentially BG), shippers (the users of the network) and gas suppliers (retailers of all kinds). The supply licence, issued only to companies judged by Ofgas to be financially secure, imposes a number of conditions including non-discrimination and an obligation to provide advice on energy-efficiency improvements. The Act also provided for the creation of a comprehensive code of practice for the regulation and use of the network, known as the Network Code.

Competition in the residential sector was extended in stages to all customers across Britain over a two-and-a-half year period from 1996 to 1998. The first pilot programme, covering 500 000 customers in the Southwest of England, was launched in April 1996 and the second, covering an additional 1.5 million customers in South and Southeast England, in February and March 1997. Implementation of the third and final phase began in November 1997 in Scotland and was completed in

May 1998 in Greater London[34]. Centrica will continue to supply existing customers until or unless they choose to sign up with an alternative supplier. Switching rates have accelerated since the start of the programme. Of the two million customers covered by the first two phases, roughly 25% had switched to an alternative supplier by late 1997. Price and public awareness have been the main factors driving switching: price discounts offered by alternative suppliers have been of the order of 10% to 20%.

Ofgas continues to regulate the prices charged by British Gas Trading. An agreement reached in late 1997 caps BGT's bundled gas prices (including transportation costs) and meter-reading costs to small consumers at RPI-4% over the period 1997-2000. In practice, BGT may reduce prices by more than the amount required under this agreement depending on the degree of competition from new suppliers to the small-residential market: Ofgas approved a BGT plan to cut its tariffs to residential customers in Phase II areas in late 1997 to defend market share.

## REGULATION OF TRANSPORTATION AND STORAGE TARIFFS

### RPI-X Price Controls

As the *de facto* monopoly owner and operator of the gas transmission and distribution network and storage facilities, BG Transco and BG Storage remain subject to regulation by Ofgas to prevent abuse of market power and ensure security of supply. The 1986 Gas Act specifies that a transporter is entitled to recover operating, maintenance and capital costs including a return on assets, excluding any costs associated with the transporter's business as a gas trader or any other non-transportation activities.

The regulation of BG's tariffs has evolved as its business has shifted from providing a bundled transportation and sales service to pure transportation service. In the tariff market, prices have been limited by the RPI-X+Y formula, covering periods of five years, regulated by Ofgas. The five-year formula which came into effect in April 1992 initially limited price increases to RPI minus 5% for non-gas costs. Increases in Y were capped by the gas-cost index minus an efficiency factor.

### 1993 MMC Report

Disagreement between BG and Ofgas over the methodology to be used for determining transportation charges and the decision by Ofgas to reduce the tariff market to 2 500 therms/year in 1992 led to several referrals to the MMC, which reported its conclusions and recommendations in 1993. Its main findings were as follows:

34. The full opening of the residential electricity market to competition has been delayed until 1999.

- That BG be required to unbundle its transportation and storage division from the company's gas trading divisions.

- That there should be a minor relaxation of the tariff formula, primarily to offset the reduction in the size of BG's tariff monopoly.

- That BG's transportation and storage activities be subject to various types of regulation, including:

  — the adoption of an RPI-X system which would ensure a rate of return on assets of 6.5% to 7.5% for new investment and 4% to 4.5% for pre-1992 assets; and

  — a requirement that BG retain responsibility for maintaining the security of the network, balance supply and demand and enable competition in metering.

- That the removal of BG's tariff-market monopoly would be beneficial to consumers (see above)

In response to the MMC's reports, the President of the Board of Trade (Secretary of State for Industry) decided to require only the internal separation of BG's trading and transportation/storage activities, which were later named BG Trading and BG Transco. In 1994, the regulator implemented the MMC's recommendation to rebase the price-control formula to apply only to the tariff market under 2 500 therms/year and to reduce the X component from 5% to 4% in line with the MMC's recommended rate of return. Ofgas also introduced an RPI-X formula for transportation and storage charges for 1994-7, with X set at 5% based on a nominal 1993/4 base price of 14.16p/therm.

## 1997 MMC Report

In 1996, Ofgas called on the MMC again to report on its proposed change in the pricing formula for the period 1997 to 2002. MMC reported its findings in July 1997, and these were for the most part accepted by Ofgas. Following a period of consultations between Ofgas and Transco regarding the implementation of the MMC recommendations, Ofgas announced in October 1997 final proposals which were endorsed by Transco. Key elements of the proposals include:

- An initial reduction in average charges amounting to 21%, equivalent to around 13% allowing for past under-recovery of revenues by BG. Future charges will be increased by no more than RPI-2% per annum.

- The structure of the transportation charges formula is to be changed to allow only 50% of revenues to vary with actual volume transported, in an effort to prevent BG from making excessive profits due to higher-than-forecast volumes over the five year period while retaining an incentive for BG to invest in network expansion. The other 50% of revenues are to be fixed on the basis of forecast throughput. The formula will also distinguish between large and small users, both capped by the RPI-X formula (the previous formula, with a 100% volume-related price cap for all users, provided the company with too great an increase in revenue from connecting power stations).

- Charges for transportation and storage are to be regulated separately. A separate revenue cap has been established for storage for the five years to 2002 amounting to approximately £160 million ($250 million), including £96 million ($150 million) for the offshore Rough facility, for each storage year beginning 1 May. BG Storage sets the structure of prices for storage services based on forecast demand so that revenue stays within the cap. In 1998, BG Storage reduced the price of Rough deliverability by 50% (to £3.08/peak-day therm) but raised the price of space by 25% (to 4.95p/therm) for the 1998/9 season[35].

## Transportation Pricing Methodology

Under the 1986 Gas Act, the pricing structure adopted by BG Transco is required to be cost-reflective. Transco's pricing structure involves different charges for the National Transmission System, Low Pressure Transmission System, and the distribution system as well as a customer charge. All charges involve a fixed (capacity) and variable (commodity) component. Only NTS and LTS charges are distance-related, through higher entry charges for entry points furthest from demand centres. For small sites (under 25 000 therms/year), capacity and commodity charges are combined into a single throughput charge assuming a 39% load factor.

Until recently, actual charges were set in such a way that Transco's total costs were recovered more-or-less equally from the capacity and commodity elements. This structure was based on a cost-allocation methodology derived from engineering estimates of the difference in the average cost of transporting gas given actual load factor and a hypothetical 100% load factor. The company has modified its methodology towards greater recovery of costs from capacity charges for the NTS: 65/35 in 1997/8, rising to 75/25 in 1998/9[36]. This move will bring pricing more into line with North American practice, where more than 90% of transmission costs are recovered from capacity charges. Transco has also proposed a rebalancing of charges between the different tiers, so that NTS charges will decrease relative to Local Distribution Zones (LTS and distribution) and customer charges. Ofgas is reviewing these proposals.

Transco has also proposed a new methodology for NTS charging, based on the introduction of three pricing nodes to replace the single national balancing point (NBP). At present, a uniform commodity charge is applied to all gas throughput on the NTS, giving no cost benefit to customers located near to entry points. Transco believes the new approach would better reflect distance-related transportation costs, and that this would promote greater efficiency in the use of, and investment in the NTS. There are concerns, however, that this move would increase paperwork and would fragment spot and futures trade which is currently based largely on the NBP. Ofgas is considering Transco's proposal.

35. For details of storage services and prices, see BG Storage, *Storage Services 1997/8* (1997).
36. The British gas year runs from 1 October.

## BG Demerger

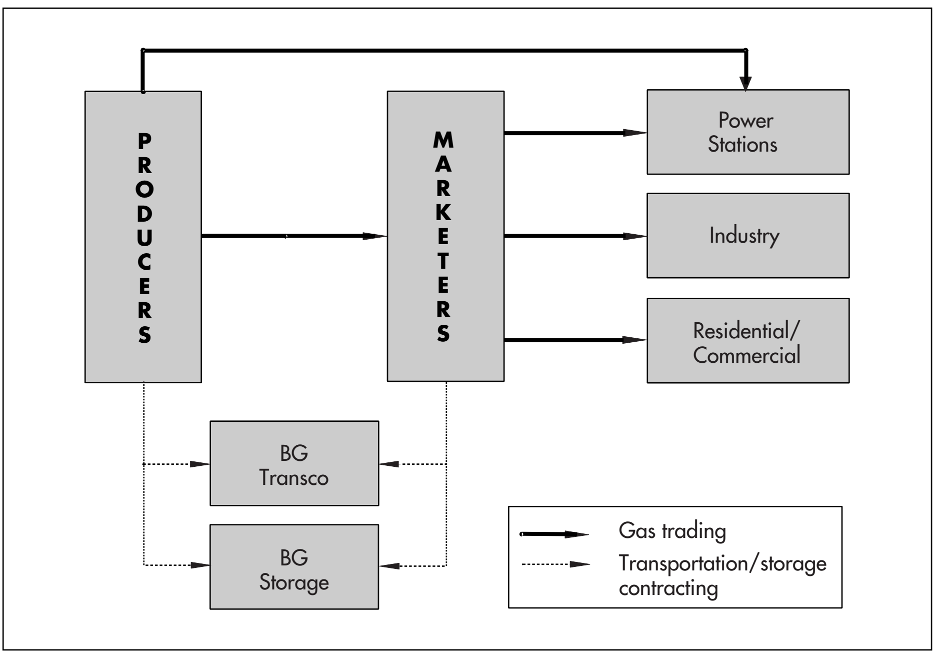
In early 1997, BG decided to demerge its gas trading and pipeline activities as originally recommended by the MMC. Centrica plc was formed as the holding company of BG Trading, with the right to operate under the name of British Gas in the Britain. The Morecombe field was allocated to Centrica, as a subsidiary called Hydrocarbon Resources. BG plc was set up as the holding company of Transco, BG's exploration and production business, international downstream investments and other related businesses. In September 1997, BG plc reorganised the UK storage activities, until then in the hands of Transco, into a new division, BG Storage.

# 4

# IMPACT OF RESTRUCTURING ON GAS CONTRACTING AND PRICING MECHANISMS

The regulatory reforms outlined in the previous section have led to a radical restructuring of the British gas industry, involving major changes in the way gas and transportation and storage services are traded and priced. The new contractual framework and pricing mechanisms are described below. Figure B-5 illustrates the main contractual relationships in the restructured industry.

*Figure B-5*
**Principal Contractual Relationships**




## CONTRACTING FOR TRANSPORT AND STORAGE SERVICES: THE NETWORK CODE

The 1995 Gas Act requires BG Transco, as the sole national Public Gas Transporter licensee, to establish a Network Code, setting out standard terms and conditions that apply to any shipper wishing to use BG's transportation network and storage facilities. As such, the Code constitutes the contractual regime for management of the commercial and operational aspects of gas transportation in Britain. It was drawn up by Transco in consultation with the industry and put into operation in 1996. The Code was deemed necessary in view of the transition to a fully competitive market. Previously, all gas transported through BG's network for third parties was covered by the original open-access contracts — now referred to as "legacy" contracts — introduced in 1989. These contracts specified both the beach delivery point and specific customer offtake points.

Key aspects of the Code include the following:

- ***Daily balancing:*** All shippers are required to balance their deliveries and offtakes on a daily basis around a notional National Balancing Point (NBP). This requirement replaces the former monthly balancing regime. Transco is responsible for correcting any shipper imbalances by buying or selling gas via a flexibility mechanism (see below). Any net costs incurred in rebalancing the system are passed on to the offending companies, the level of penalties being determined by the degree of transgression.

- ***Top-Up Manager:*** An organisation within Transco, known as the Top-Up Manager, is responsible for ensuring that enough gas is injected into and held in storage during the summer to meet expected peak winter demand taking account of projected beach supplies. Storage is booked by shippers, but their bookings may be deemed insufficient to meet seasonal demand needs. The Top-Up Manager may buy gas and inject it into unbooked empty storage according to the Manager's estimate of the difference between the amount of storage that has been booked by shippers and the amount that the Manager believes will be required. The Manager may make this gas available on peak days, either though the flexibility mechanism or by direct sale to a shipper with booked storage space but insufficient gas, in both cases at a predetermined very high price. Any costs or profits made by the Top-Up Manager are recovered from or reimbursed to shippers in an equitable manner.

- ***Reserving entry and exit capacity:*** Shippers are required to book capacity for a period of 12 months at each of the entry points on the Transco system where they intend to deliver gas. They are also required to reserve exit capacity at specific exit zones (of which there are 37) for their daily-metered firm sites — the largest industrial and power station customers. Transco automatically allocates non-daily-metered exit capacity. Shippers are thus able to match deliveries and offtakes in a flexible manner, without having to allocate deliveries to specific entry points to offtakes at specific exit points under individual contracts corresponding to each customer, as was previously the case[37].

- ***Secondary-capacity trading:*** Under the Network Code, shippers are also able to trade capacity among each other. Transco maintains a computer-based market

37. Umbrella and Gas Transfer Contracts used to provide shippers with a degree of flexibility in matching deliveries and offtakes under the old regime.

on which shippers can post bids for and offers of capacity. Alternatively, shippers are free to trade capacity directly without using the Transco market, but transfers of entitlement to capacity are required to be registered with Transco. The shipper who initially booked capacity remains liable for payment of the capacity charges to Transco. There are no price controls. To date, secondary-capacity trading has been modest, amounting to 8% of total system throughput in the winter of 1997/8[38].

- ***On-system gas trading:*** In cases where a shipper has spare entry capacity, he may sell gas "on system" to another shipper who is short of gas or gas-entry capacity at the NBP. The sale may take place either before or during the gas flow day. Having agreed on a trade at a mutually acceptable market price, the two parties each create a gas nomination which specifies the other party instead of an entry of exit point: so long as the nominations match, Transco approves the trade, but takes no part in the financial transaction.

- ***Attribution of demand to non-daily-metered sites:*** Although the Network Code requires shippers to balance their deliveries and offtakes on a daily basis, the system does not provide shippers with daily metering information from the majority of sites. Only the largest industrial and commercial sites are metered daily[39]; residential customers' meters are normally read only once or twice a year. To deal with this problem, Transco uses an algorithm — a very complex mathematical formula — to estimate demand at each small NDM site, according to the size of the site, load profile, location and local weather conditions. These calculations are performed before each gas-flow day. Demand is apportioned to each shipper and shippers are informed of their individual total NDM demand for the next gas-flow day. Shippers are then required to nominate how much gas they will need to transport or store by 15.00 on the day before the gas-flow day. Transco schedules its daily operations accordingly.

- ***Booking storage capacity:*** BG Storage makes storage capacity available to shippers through a tender in the spring for the year beginning 1 May. To date, storage has been offered at fixed prices although Ofgas favours an auction[40]. No capacity may be booked after 30 November. Depending on the total amount of storage booked by shippers and expectations of the Top-Up Manager's needs, the Manager may auction off surplus capacity — at regulated rates. As with transportation capacity, shippers must contract for a full 12-month period from 1 May. Shippers may trade storage capacity, with or without gas in it, at unregulated rates at any time.

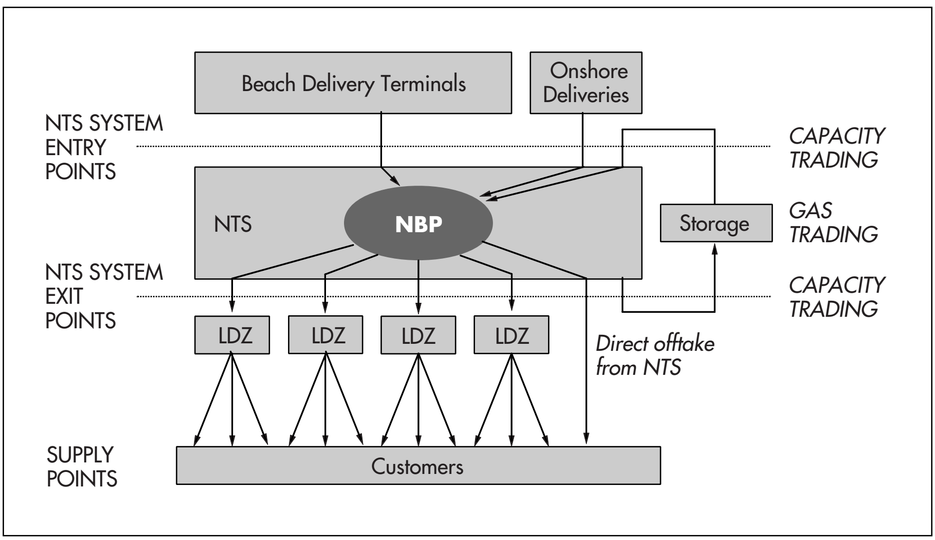
38. BG Transco, *Winter Operations Review 1998* (1998).
39. All end-users consuming more than 75 000 therms/year will eventually be metered daily.
40. Traders NGC and Enron had proposed an auction of storage services for 1998/8. BG Storage is opposed to such a move and argued that its licence allows it to decide how to price storage services as long as it charges reasonable rates and does not exceed its revenue cap. Ofgas does not accept this argument but feared that a lengthy legal dispute over the extent of Ofgas' powers in this area would not be helpful to the development of competition in storage. Ofgas subsequently launched a review of the structure of the storage market and the behaviour of the main participants.

■ ***Transco interruptions:*** In exceptional circumstances, Transco may interrupt delivery to sites in strategically important areas of the system, for example to relieve a capacity constraint. To prepare for such an eventuality, Transco makes arrangements with shippers, under which some of their largest customers' sites are declared interruptible. No National Transmission System (NTS) exit or Local Distribution Zone (LDZ) capacity charges are levied on these sites. Transco must not discriminate between shippers in deciding on interruptions. In practice, only about 10% of all interruptions are imposed by Transco: all other interruptions are determined by shippers, for load balancing reasons.

Figure B-6 illustrates the physical gas flows in the Transco system and opportunities for capacity and gas trading under the Network Code regime.

*Figure B-6*

**Physical Gas Flow Paths Through Transco Network**

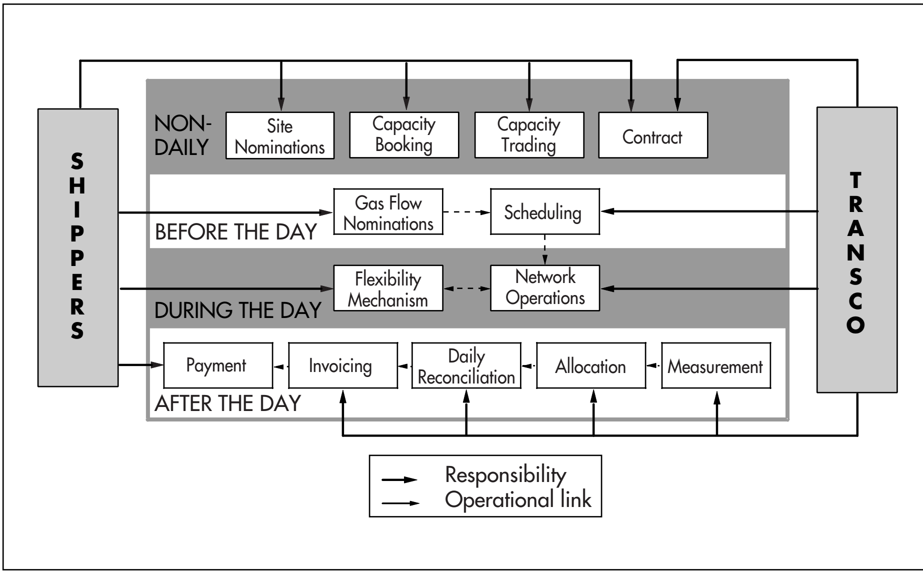



Source: Transco, *Network Code - The Summary* (1998)

Figure B-7 summarises the operational and commercial relationships between Transco and shippers and their respective responsibilities at specific times.

The Network Code was introduced in phases to allow time for market players to get used to the new regime. During the bedding-in period, known as the "soft landing", which began in April 1996, shippers' daily imbalance tolerances were set at high levels to minimise the penalties. Full implementation of the Code — the "hard landing" — took place in September 1996. For the most part, the code appears to be working well. Some shippers have, however, complained about the workings of the flexibility mechanism, which has led to pronounced within-day price fluctuations and severe financial penalties for those shippers who have not been able to maintain a close balance between deliveries and offtakes (see below).

*Figure B-7*
**Network Code Responsibilities**




Source: Transco, *Network Code - The Summary* (1998)

# LONG-TERM CONTRACTS FOR GAS SUPPLY AT THE BEACH

Despite the enormous changes to the British gas market over the past ten years or so, more than 80% of the bulk gas sold to gas marketers and shippers at the beach or terminal is still supplied by producers under long-term contracts signed in the late 1970s, 1980s and early 1990s. Most of these contracts, which are all for firm supplies, cover the entire life of the gas field to depletion. These contracts contain provisions for swing whereby the daily contract quantity in winter can be considerably higher than the average annual contract quantity[41]. They also include take-or-pay, under which the buyer is obliged to pay for a minimum volume of gas (typically 70-80% of the annual contract quantity) whether it is lifted or not. Prices are indexed to crude oil and/or oil-product prices (typically heavy fuel oil and/or gas oil) and, in some cases, on an inflation index.

The majority of these depletion contracts are held by Centrica, which acquired them from the old British Gas (BG) at the time of the demerger. Most of Centrica's gas at the beach is still supplied under depletion contracts signed before competition started to make inroads into its industrial and commercial markets in the early 1990s. Some of the gas contracted by BG was released to other gas marketers in the early 1990s. More recently, Centrica has been obliged to

41. Swing in some contracts is thought to be as high as 200%, i.e. peak daily offtake in winter can be twice the average annual contract quantity.

renegotiate some contracts that had become uncompetitive, as gas prices fell further than oil prices. These renegotiations involved either rebasing and revising of the price escalation clauses or cancellation of the contract, with compensation paid to the producers (see box). As BGT, the Centrica trading subsidiary, loses residential market share with the introduction of full competition, it is expected to sell unwanted volumes acquired under its depletion contracts onto the spot market.

### BG's Take-or-Pay Contract Problem

The oversupply of gas that emerged in the British market in 1995 led to a sudden collapse in the spot market from 19p/therm at the start of the year to below 10p/therm a few months later. Since BG's competitors were beginning to acquire a significant proportion of their gas from the spot market, BG found itself paying significantly higher prices for its bulk gas supplies under its long-term depletion contracts. The large swing provisions in those contracts somewhat alleviated the problem by allowing BG to lift much of the gas during the winter season when prices are generally higher). BG's difficulties in competing in the industrial and commercial markets were exacerbated by the Government's decision to introduce competition in the residential market over the years 1996 to 1998. These problems led Centrica, which took over the contracts from BG, to seek renegotiations with its North Sea suppliers in an effort to establish a viable basis for trading competitively over the long term. Those suppliers, for their part, were interested in reducing the onerous swing obligations in those contracts.

From the end of 1996 to the beginning of 1998, Centrica renegotiated terms on 46.5 billion therms of its highest priced gas contracts — equivalent to around a third of its total supplies — with BP, Mobil, Amerada, Enterprise, OMV, Arco, Eastern, Total, Elf and Conoco. Over half of this contracted volume was cancelled, while the base prices were lowered and market-related price indexation introduced on the remainder. Centrica paid around $1.2 to $1.3 billion in cash and assets as compensation, but was not obliged to sell the strategically valuable Morecombe field used to meet BGT's peak-load requirements. Centrica announced in January 1998 that the take-or-pay problem had been largely resolved, with the company's weighted average cost of gas reduced to around 15p/therm. Further renegotiations will probably not be necessary unless spot prices decline further.

New gas available from the North Sea continues to be sold for the most part under fixed-term contracts — either to gas-marketing companies (which are often the subsidiaries of the producers) for supply at the beach or direct to CCGT power stations. In the early- to mid-1990s, there was a shift to supply contracts of 5 to 10 years duration, with prices still indexed mainly to oil prices. Today, beach contracts are typically for three-to-five years, although some ten year contracts are still negotiated, with prices indexed for the most part on spot or futures gas prices.

Supply may not necessarily be from a named field. Increasingly, North Sea producers hold back a proportion of the gas available from new fields over and above that committed under term contracts and sell it on the spot market. Some companies are considering developing fields without any fixed-term contract in place and selling all the gas on a purely spot basis, that is, in fixed-price deals covering supply of as little as one day and up to one year.

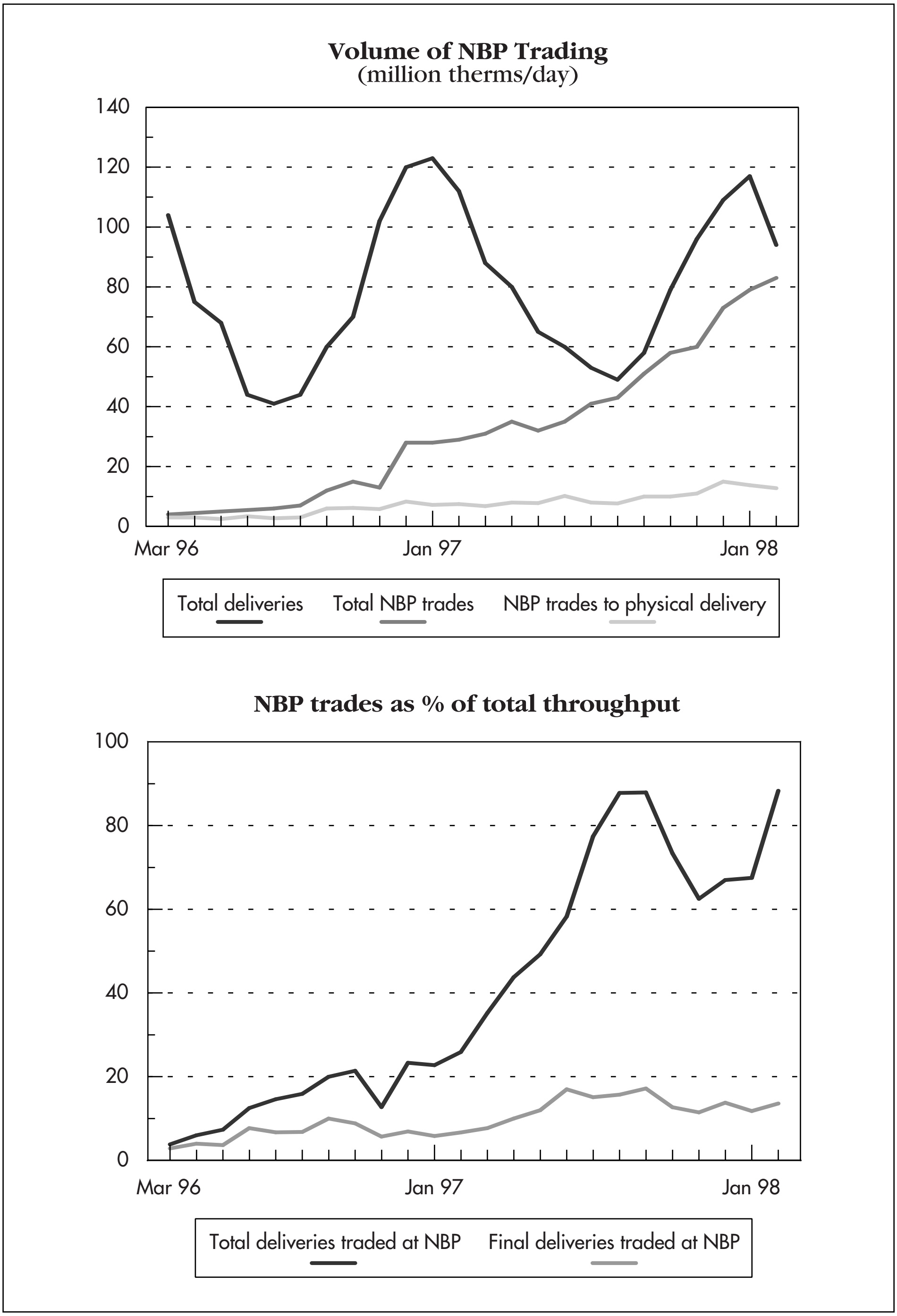
With the move away from named fields in term contracts and the introduction of daily balancing requirements with heavy price penalties for imbalances on peak days, producers are increasingly concerned with ensuring back-up supplies at short notice in the event of unscheduled production shutdowns. Some of the larger producers, with 24-hour manned-operations facilities, now offer to provide emergency cover for smaller producers who are less able to respond quickly to a sudden loss of supply from a particular field. The price risks inherent in the old long-term depletion contracts have led to the emergence of a market in management of financial risk. Financial services companies offer to take on the risk that prices in those contracts move out of line with market levels, exposing the contract holders to potentially large losses.

## SPOT MARKETS

Spot markets consist of over-the counter (OTC) standardised trades, made bilaterally or through a broker, for supplies of gas at a fixed price over fixed delivery periods. Delivery can be for varying periods, between one day and a year or so, either for prompt or forward delivery. Spot-market participants include equity producers, shippers buying and selling gas to balance their portfolios, end users, power generators seeking gas for their own needs and speculative traders. A standard contract, originally drawn up by BP Gas and setting out detailed terms and conditions for spot transactions, was adopted by most of the trading community at the end of 1997 to replace the plethora of contracts that had been in use. Although most spot trade is confidential, estimates of market prices for different categories of spot trades are published by specialist price-reporting services. Those estimates are, in turn, used as the basis for price indexing in some term contracts and risk-management instruments such as swaps and OTC options, much as it is done in the oil market.

Spot trading began to develop in 1993 and has grown rapidly in the last two years. By November 1997, the total volume of gas trading had reached almost 80% of actual daily NTS throughput, but this is somewhat misleading since the "80%" includes re-trading. Each unit of gas traded spot was sold on average a further 4.8 times before being delivered to the final customer (see Figure B-8). The proportion of gas physically delivered which is first sold on the spot market was thus around 15%, having peaked at 18% in October 1997. The ratio of final deliveries initially traded spot at the NBP to total throughput tends to be higher in the summer, since peak winter throughput is dominated by Centrica, which makes relatively little use of the spot market.

*Figure B-8*
**Spot Trading at the NBP**




Source: BG Transco

The pattern of spot trading has changed markedly over the past four years. Initially, most trades involved delivery for the first full month forward. Since 1995, trading has become more diverse, with greater emphasis on day-ahead and within-day trading (reflecting the introduction of daily balancing requirements under the Network Code) as well as quarterly forward deals. Typical transactions involve 25 000 to 50 000 therms/day, though some much larger volumes are traded spot. Another major change has been the shift in delivery points. Until the introduction of the Network Code in early 1996, most trading involved delivery to Bacton or St Fergus. Now, over 90% of trading is for delivery at the NBP (thus including Transco's NTS entry charges, which vary from 0.03p/therm at Bacton to 0.6p/therm at St Fergus). Such trades have become more attractive to shippers because the gas traded can be directly registered with Transco as involving gas within the system, thereby counting towards the shippers' daily balances.

## FUTURES MARKET

In February 1997, the International Petroleum Exchange in London launched a screen-based trading system for natural gas futures contracts. As in the United States, the system provides a transparent mechanism for hedging, speculation and, in some cases, physical delivery. The delivery point for gas is the NBP, a fact which limits the basis risk for hedging spot NBP trading. Trading is for individual days up to a week out, the balance of the current month and calender-month periods extending out 15 months. The volume of trading in the IPE gas contract has steadily increased, but it remains much lower than the volume of OTC spot trading (around 15% to 20% by the beginning of 1998). Trading has been dominated by a small number of players: one trader claims to have been involved in around a third of all futures deals. IPE prices are starting to be used as the basis for price indexing in term contracts: a ten-year supply contract covering 5 billion therms from Enron to Centrica starting in 2001, and announced in February 1998, is priced in this way.

**IPE Gas Futures Contract Specification**

- Firm supply for delivery at NBP
- Transco pipeline quality
- 100% take-and-pay
- No swing
- Flat delivery through the gas-flow day
- Lot size: 1 000 therms/day; minimum trade: 5 lots
- Minimum price variation: 0.005p/therm
- Shortfall provisions:
  - — Seller default: 30% to 100% provisions
  - — Buyer default: 100% of contract value

Proposals by Transco to change its system-pricing structure based on three geographical nodes, outlined in the previous section, would have significant implications for the IPE contract and spot trading. There are concerns that nodal pricing could lead to a fragmentation of trade and a loss of interest in the IPE contract, if it were to be based on a single node for delivery purposes. The IPE is also looking into the possibility of launching a European gas-futures contract in anticipation of short-term trading that is expected to develop after the Interconnector is commissioned in October 1998.

## FLEXIBILITY MECHANISM

The flexibility mechanism or market is Transco's core instrument for meeting its responsibility to balance gas deliveries and offtakes to and from the system under the Network Code. The market, organised by Transco, is intended to identify the actual marginal costs of balancing the system over any gas-flow day, thereby providing correct price signals to shippers in balancing their portfolios. This is achieved by means of open bids to buy or sell whatever amount of gas is required to balance the system at any given time; the prices obtained from such flexibility transactions are then used to "cash out" individual shipper imbalances, i.e. charges for shippers short of gas and payments for shippers who have oversupplied. In winter 1997/8, the flexibility market provided around 47 bcf (1.33 bcm) of gas, roughly 2% of total system throughput. The market operated on 91% of winter days.

The Code makes an important distinction between days on which the system is in balance and days when it is not (within certain tolerances):

- When the system is balanced overall, individual shippers who are out of balance have to pay or are compensated for their imbalances at the system average price (SAP), the average price paid or obtained by Transco in balancing actions over the gas-flow day.

- When the overall system is out of balance, individual shippers who are out of balance are obliged to pay or are compensated, subject to certain tolerances, at the system marginal price (SMP), the highest or lowest price paid by Transco for a tranche of gas on the gas-flow day. The SMP, which can be high on peak days when the system is undersupplied, thus acts as a financial penalty to shippers who do not maintain a tight daily balance. The SMP is broken down into two prices, buy and sell. This, in effect, provides a commission to Transco to cover its costs.

On peak days, shippers may be able to find additional gas to bid into the flexibility market from three sources:

- Increasing supplies under beach contracts.

- Use of contracted storage.

- Demand management, usually by interrupting customers.

Under extreme circumstances, Transco can call on bids from the Top-Up Manager. Under the Network code, prices charged for this gas are 50 times the actual cost of storage. This comes out at around £12/therm for Rough storage and £15 to £38/therm for LNG. Transco is required to cover its costs from operating the flexibility market and no more. Any net costs incurred or revenues earned are charged back or reimbursed to shippers on a weighted use-of-system basis.

The flexibility market, which has been in full operation since September 1996, has proved controversial because of occasional very high levels of SAP and SMP at times of peak demand, sometimes coinciding with offshore production difficulties. The Network Code rule, that requires BG Storage automatically to interrupt all interruptible storage when demand reaches 85% of Transco's estimate of a 1-in-20 year[42] peak day, is thought to have contributed to price spikes over the last two winters. The rule, which was intended to give Transco greater flexibility in meeting peak-day load by drawing on the Top-Up Manager's storage and to give shippers a strong incentive to book sufficient firm storage capacity, was removed in spring 1998. Ofgas announced in May 1998 its intention to replace the flexibility mechanism with an alternative, screen-based within-day market. It has invited expressions of interest from companies wishing to operate such a market[43].

## END-USER SALES

The types of contracts used to supply end user customers and the pricing mechanisms in those contracts vary primarily according to customer category.

### Power Generation

Contracts to supply power stations typically cover supply of 50 to 100 million cf/d (185 to 370 million therms/year, or 0.5 to 1 bcm/year). Contracts to supply nine CCGTs with total capacity of around 4 GW in the early 1990s were signed with British Gas (now Centrica). These contracts, covering around 7 to 8 bcm/year, are for interruptible supply over 10 to 15 years. They provide for a take-or-pay threshold of around 70%, maximum interruption of 45 days/year and 300 days over 15 years and swing of around 130% of daily contract quantity. The base price in these long-term interruptible (LTI) contracts is escalated on a variety of indices, including the price of coal and heavy fuel oil, the electricity pool price and inflation (PPI). Most contracts include a combination of indices, almost always including the pool price as one of the elements. The contracts cover around 55% of the gas currently purchased by the stations to which LTI gas is supplied.

42. An exceptionally cold day with a 5% probability of occurring.

43. Ofgas, *An On-The-Day Commodity Market for the Gas Balancing Regime* (Consultation Paper, May 1998).

Most power station contracts signed since 1992 have been with gas marketers other than British Gas (Centrica). Most are long-term (10 to 15 years), although some are short- or medium-term (for example, a 47 MW Combined Heat and Power plant at Runcorn commissioned in 1997 is supplied by Centrica under a five-year interruptible contract). Take-or-pay commitments in recent long-term contracts have generally been around 90%. Contrary to the early BG LTI contracts, most of these recent contracts are for firm supply. Swing is typically around 120% of daily contract quantity. Price indexing terms vary: marketers often prefer standard PPI or oil-price escalation, while power project developers generally prefer pool-price escalation. Actual terms depend on the base price: pool-price escalation, at present, involves a higher base price because of the perceived greater risk of lower pool prices in the future[44].

## Industrial and Commercial Customers

All industrial and commercial customers (consuming more than 2 500 therms) can contract for firm or interruptible gas from competing licensed suppliers, of whom there are currently around 70. Contract terms and duration vary considerably. One-year contracts are still the most common. There are a number of contracts of shorter and longer duration, though rarely for more than three years. There has been considerable switching of suppliers among larger customers in response to keen competition, largely on price.

Most contracts of one year or less specify a fixed price for delivery to a given site or group of sites. Some large contracts of longer duration have escalation based on published spot gas indices or oil prices. Interruptible contracts typically provide for a maximum number of days of interruption. Under some recently negotiated contracts, customers may be compensated for being interrupted. Some firm contracts now provide the buyer with the option of accepting interruption in return for compensation, which is usually high per therm interrupted. Increasingly, marketers seek to cover industrial/commercial sales contracts with back-to-back purchases on the spot market to lock in a gross margin (taking account of transportation costs).

## Residential Customers

Until the phased introduction of competition from 1996 to 1998, British Gas (Centrica) was the monopoly supplier to residential customers consuming less than

44. Until recently, the gas supply contracts of virtually all committed gas-fired power stations have been covered by back-to-back long-term electricity supply contracts for differences with regional electricity companies (RECs). These contracts escalate the electricity price in a similar way to the gas-supply contracts, locking in the margin for the power project. Because the RECs are now paying electricity prices significantly above current pool price levels, they are less prepared to sign contracts for differences especially in view of the opening up of the residential electricity market to full retail competition in 1999. New power projects will, therefore, probably have to sell most of their power into the pool without back-to-back contracts, increasing the imperative for them to contract for gas at a low base price, with pool-price escalation and/or for a shorter term duration (one to five years) to ensure maximum flexibility in managing and arbitraging gas and electricity.

2 500 therms/year on the basis of published tariffs. The overall level of tariffs remains regulated by Ofgas; Centrica's price controls are expected to be lifted once competition in this sector is firmly established. As the removal of Centrica's retail monopoly is completed in mid-1998, some marketers to this sector, of whom 15 had been licensed by early 1998, are expected to offer package deals involving, among other services, electricity (when the retail market is opened), water and sewerage.

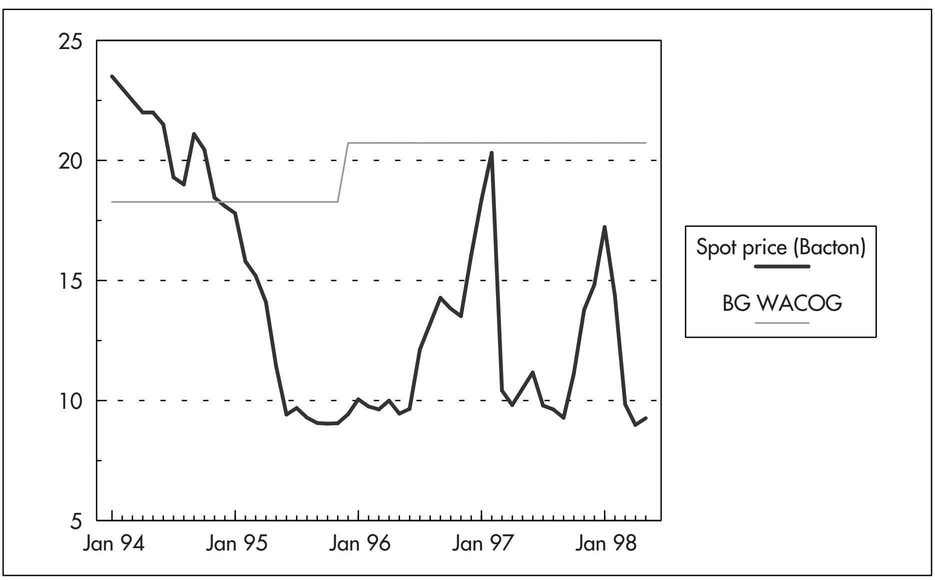
5

# NATURAL GAS PRICE DETERMINATION[45]

## PRICE TRENDS

Differences in the way gas supplies are contracted for and priced, described in the previous section, are reflected in divergent price trends and patterns across and within different stages of the gas supply chain and customer categories. In contrast to the North American market, where spot prices now largely determine prices for term-contract supplies, actual prices of bulk British gas supplies, delivered to the beach or to the NBP within Transco's transmission system, can and do vary considerably according to the type of contract. This is because bulk supplies are priced using an array of indexation formulae: only a minority are currently priced on a spot or spot-price-related basis, although this proportion is rising steadily. Centrica's gas costs, until now, have been insensitive to spot price movements (see Figure B-9). Recent contract renegotiations will take effect towards the end of 1998.

*Figure B-9*
**Spot Bulk Gas Prices at the Beach, January 1994 to May 1998**
(p/therm)




Note: BG WACOG is the weighted average cost of gas for British Gas (Centrica). The spot price at Bacton (Heren Index) is the weighted average cost of full-month gas in over-the-counter deals. Prices at the NBP are typically a fraction higher than at Bacton.
Source: WACOG: *European Gas Markets* (various issues); spot price: *World Gas Intelligence* (various issues)

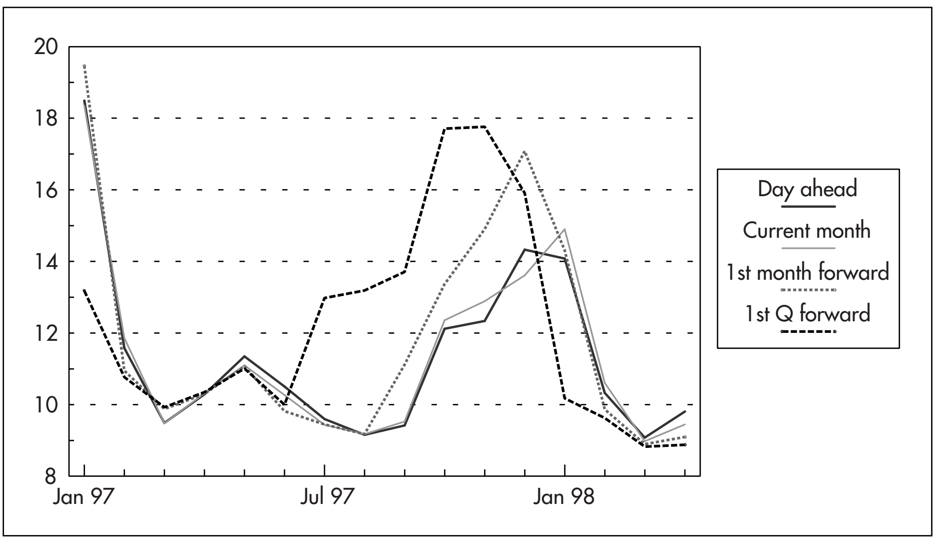
45. This section does not consider in detail price setting in the regulated tariff market for residential customer, since full competition in this sector was not introduced until May 1998.

Spot prices have shown considerable volatility over the past three years. First month-forward spot prices collapsed from an average of 23p/therm in January 1994 to under 9p/therm by summer 1995. The spot market recovered in the autumn/winter of 1996/7 to over 20p/therm on the back of a very cold spell, but quickly fell back to under 10p/therm in summer 1997. An analysis of spot prices for gas delivered to the NBP reveals a close relationship between gas for one-day-ahead and balance-of-the-month gas, and some divergence between very prompt and forward-month and quarter deliveries (see Figure B-10). There is normally only a very small difference between month-ahead spot prices delivered at the NBP and Bacton. Seasonality of spot prices emerged for the first time in 1997.

*Figure B-10*

**Spot Prices Delivered to NBP, 1997 to May 1998**

(Monthly averages, p/therm)

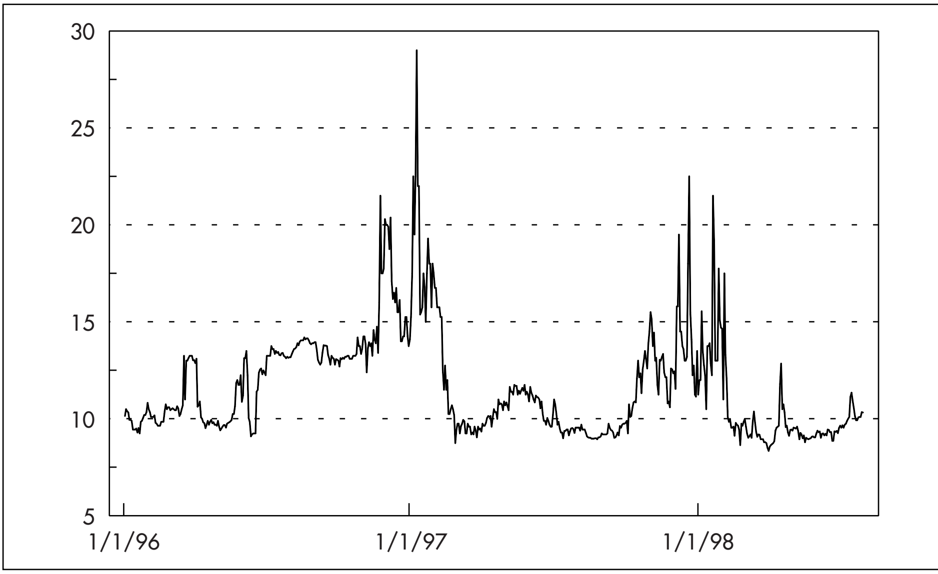



Source: *Petroleum Argus Gas Connections* (various issues)

Spot prices for very prompt delivery for the day ahead and the same day have shown even more volatility than month-on-month prices Figure B-11 plots daily prices for day-ahead gas deliveries since 1997: prices have been particularly erratic during the winter months. Price spikes, such as the one on 7 January 1997, when the average day-ahead price reached 29 p/therm and another on 17 December 1997 when the average price was almost 23 p/therm, were caused by system buys at extremely high prices by Transco's flexibility mechanism. The SAP (system average price) has on occasions exceeded £1/therm and on one occasion, SMP (system marginal price) reached almost £5/therm[46], due to cold weather and real or imaginary problems with deliveries from offshore fields (see Figure B-12).

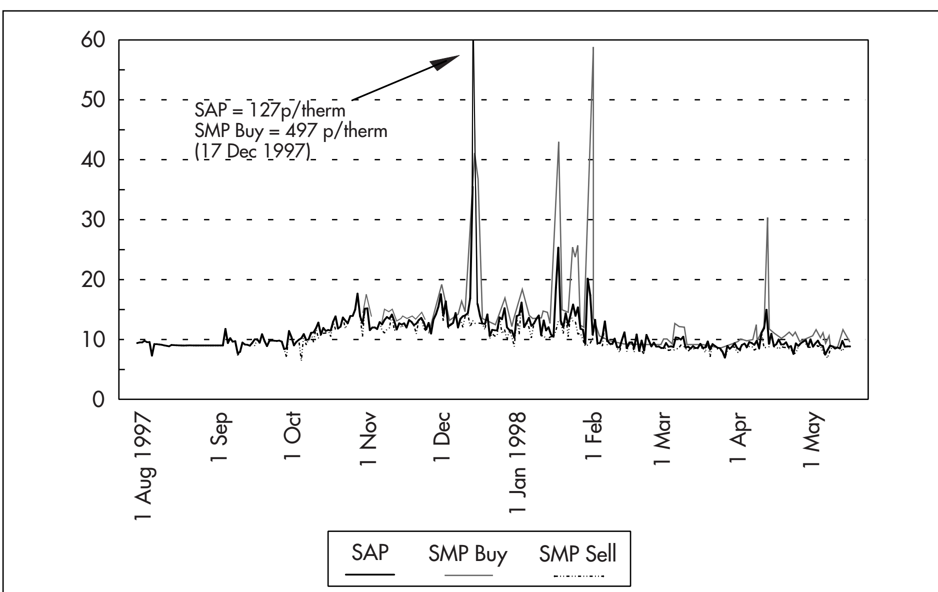
46. On 17 December 1997, offshore production problems and the sudden onset of cold weather exacerbated by the cut-off of interruptible storage under the 85% rule led to record prices on the flexibility market: SAP for the day reached £1.27/therm and SMP-buy £4.97/therm.

*Figure B-11*
**Day-Ahead Spot Prices, 1 January 1996 to 28 July 1998**
(Daily, p/therm)




Note: Bacton until 9/96; NBP thereafter
Source: Petroleum Argus

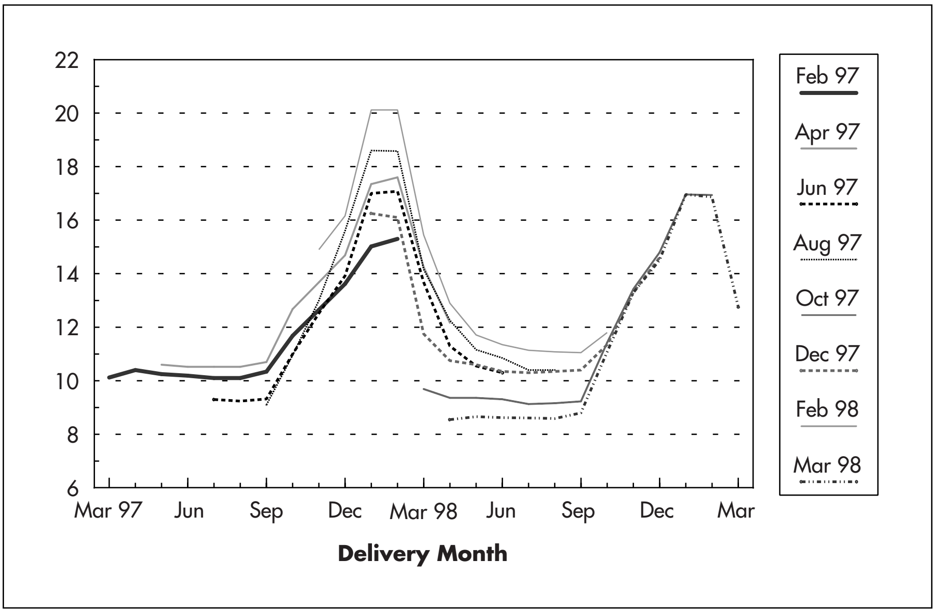
*Figure B-12*
**Transco Flexibility Mechanism Prices, August 1997 to May 1998**
(Daily, p/therm)




Source: BG Transco

Seasonality in futures prices since the IPE contract began trading in February 1997 is marked (see Figure B-13). As in the United States, near-month futures prices tend to converge on the near-month spot price at the NBP. The seasonality of forward spot and futures prices is analysed below.

*Figure B-13*
**IPE Futures Prices, February 1997 to March 1998**
(p/therm)




Source: *Petroleum Argus Gas Connections* (various issues)
Note: Prices at end-of-month settlement date for near month.

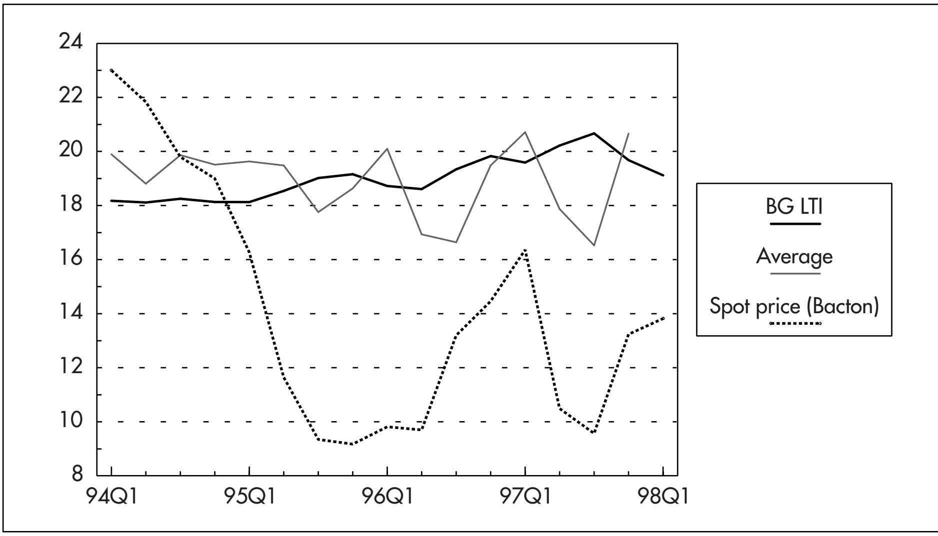
As with bulk-gas prices, end-user prices also show divergent trends depending on the pricing mechanism used in contracts. Power-sector prices under existing contracts have generally fluctuated much less than spot-gas prices, partly for historical reasons. They are largely linked to competing fuel prices, electricity prices and inflation. Figure B-14 shows that prices under BG's long-term interruptible (LTI) contracts have tended to increase gradually, while average gas prices to power generators, which include an element of spot purchases, have been more volatile.

Prices to industry began to fall steadily in 1994, picking up pace over the winter of 1995/6. After levelling off during 1996, prices for all categories of industrial customer started to rise during 1997, partly reflecting higher spot prices over the winter of 1996/7 and towards the end of 1997. Figure B-15 shows price trends since 1994 for industrial customers for firm delivery. Figure B-16 compares firm and interruptible prices to medium and large industrial customers.

*Figure B-14*

**Average Prices Paid by Power Generators Under Existing Contracts, 1st Quarter 1994 to 1st Quarter 1998**

(p/therm)

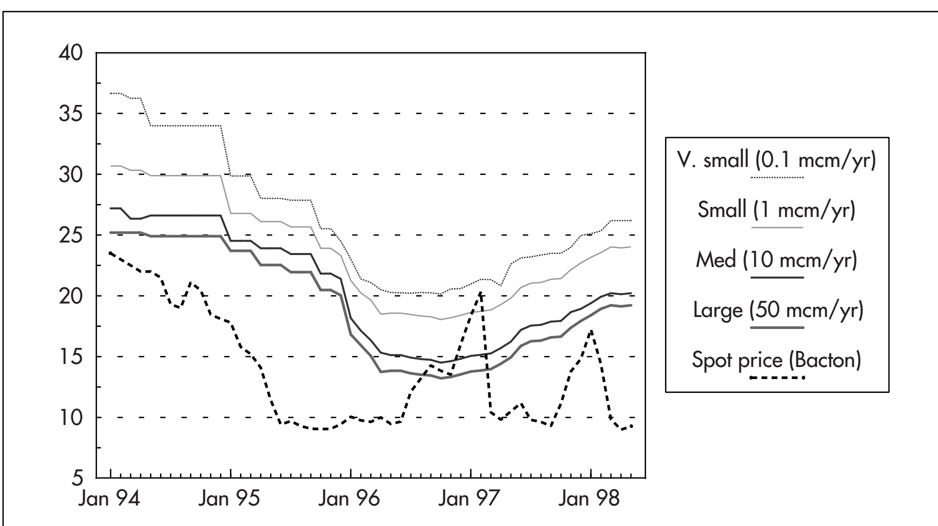



Source: BG Long Term Interruptible prices: *World Gas Intelligence*; Average gas prices to power generators: DTI, *Energy Trends* (various issues); Bacton spot price *European Gas Markets* (various issues).

*Figure B-15*

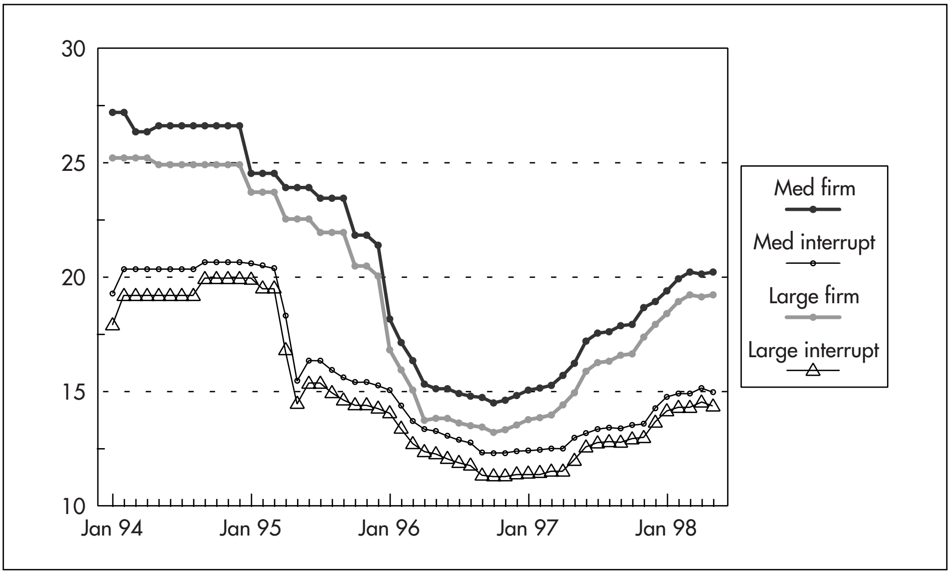
**Firm Gas Prices to Industry, January 1994 to May 1998**

(p/therm)




Source: Industry prices: *World Gas Intelligence* (various issues); Bacton spot price: *European Gas Markets* (various issues).

*Figure B-16*
**Firm and Interruptible Gas Prices to Medium and Large Industry, January 1994 to May 1998**
(p/therm)




Source: Industry prices: *World Gas Intelligence* (various issues); Bacton spot price: PH Energy, *European Gas Markets* (various issues).

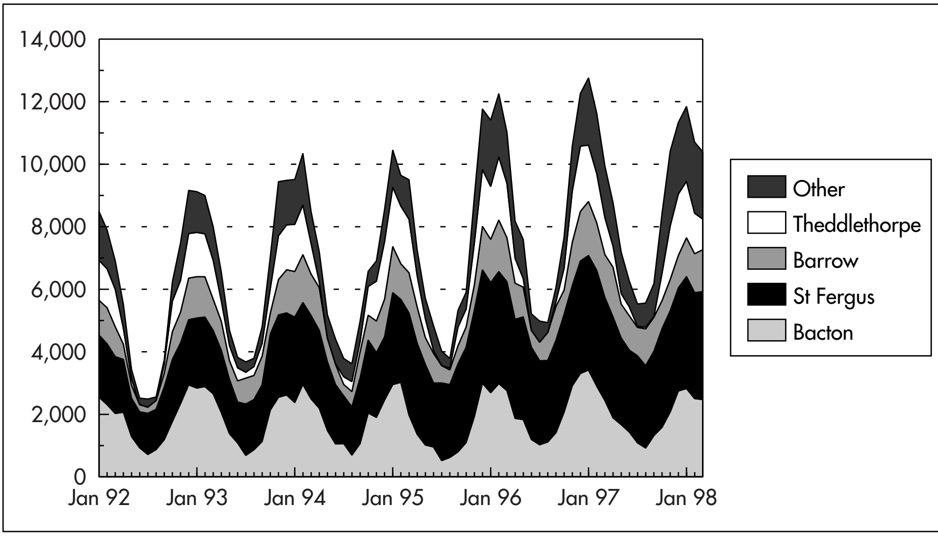
# SUPPLY AND DEMAND FUNDAMENTALS

## Production and Supply

Virtually all the gas available for supply in Britain is produced offshore in the North Sea and the Irish Sea. Traditionally, gas is produced with a high swing factor: output from the Morecombe field landed at Barrow has the highest swing of the major fields (see Figure B-17). At present, monthly availability in winter (including Rough storage) is around 2.5 times summer availability. Average production swing has fallen since the early 1990s, as proportionately more gas is used in power generation for baseload production. This has been balanced by an increase in output of gas in association with crude oil or condensates, for which swing is generally much lower because of the importance to project economics of maintaining constant high levels of oil production. With the removal of BG's monopoly, producers have also been seeking to lower swing for project economic reasons.

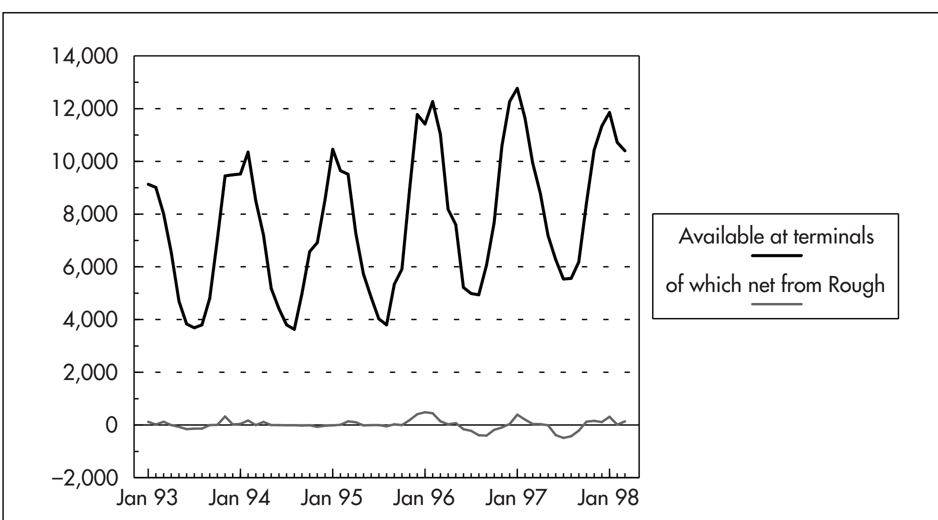
The Rough storage facility has made a significantly larger contribution to seasonal load matching since the 1995/6 heating season (see Figure B-18). Withdrawals from Rough, nonetheless, account for only a small proportion of peak-month supply. Figure B-19 illustrates the breakdown of the actual monthly load-duration curve for

*Figure B-17*
**Gas Available at Terminals, January 1992 to March 1998**
(mmcfd)




Note: Availability at the East Coast Easington terminal within the "other" category includes volumes withdrawn from (and injected into) the Rough storage facility.
Source: *Wood Mackenzie North Sea Service*

*Figure B-18*
**Gas Availability From Production and Rough Storage, January 1993 to March 1998**
(Mmcfd)




Source: *Wood Mackenzie North Sea Service*

1996 by supply source: North Sea production swing was the primary means of seasonal load matching, followed by the Centrica's high-swing Morecombe field, interruption to power generation and industry, Rough storage and peak shaving from high-cost salt-cavern and LNG storage.

## Consumptions Patterns and Trends

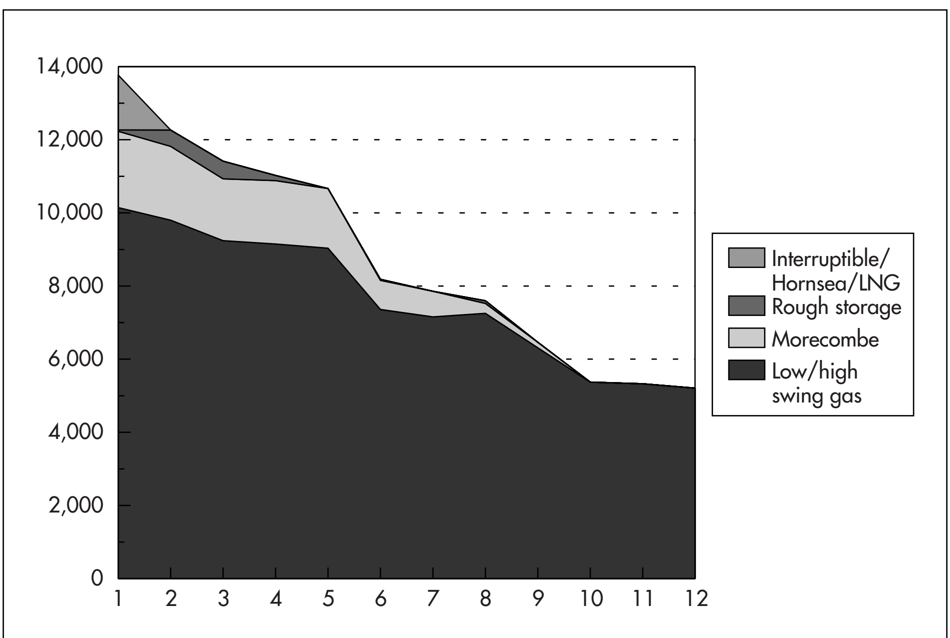
UK gas demand is highly seasonal, due largely to space-heating demand in the residential and commercial sectors (see Figure B-20). The annual load factor (defined as average daily gas demand divided by peak daily demand) is around 36% in the residential and very small commercial sector (up to 2 500 therms/year); 39% in the small commercial sector (2 500 - 25 000 therms/year); 43% in the industrial and large commercial sector (over 25 000 therms/year) and 75% to 80% in the power generation sector. The weighted average national load factor is around 45%.

Until recently, the overwhelming majority of gas sales were made from Transco's regional and local distribution networks, known as local distribution zones (LDZs). Sales off the NTS rose from 5% of total throughput in 1992 to 18% in 1996, primarily due to the increase in large-volume power-generation offtake (see Figure B-21). There has also been significant growth in NTS sales to industry (predominantly under interruptible contracts).

*Figure B-19*

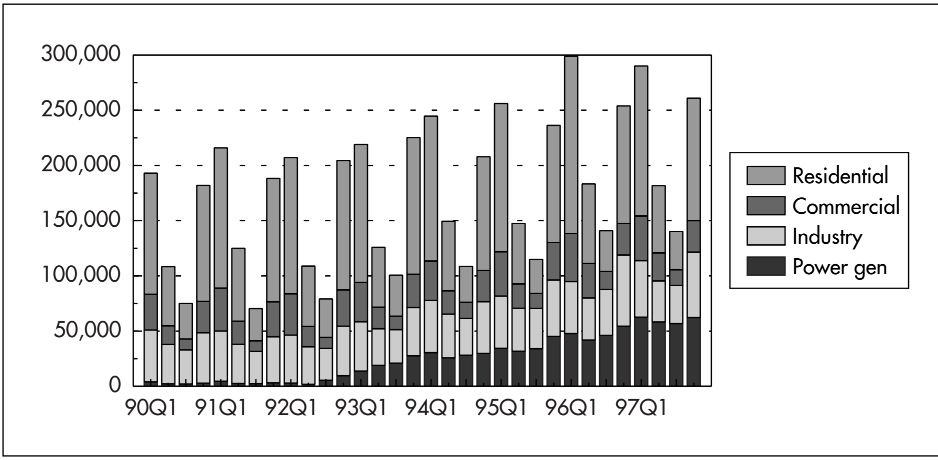
**Monthly Load Duration Curve for UK Gas Supply, 1996**

(Mmcfd)



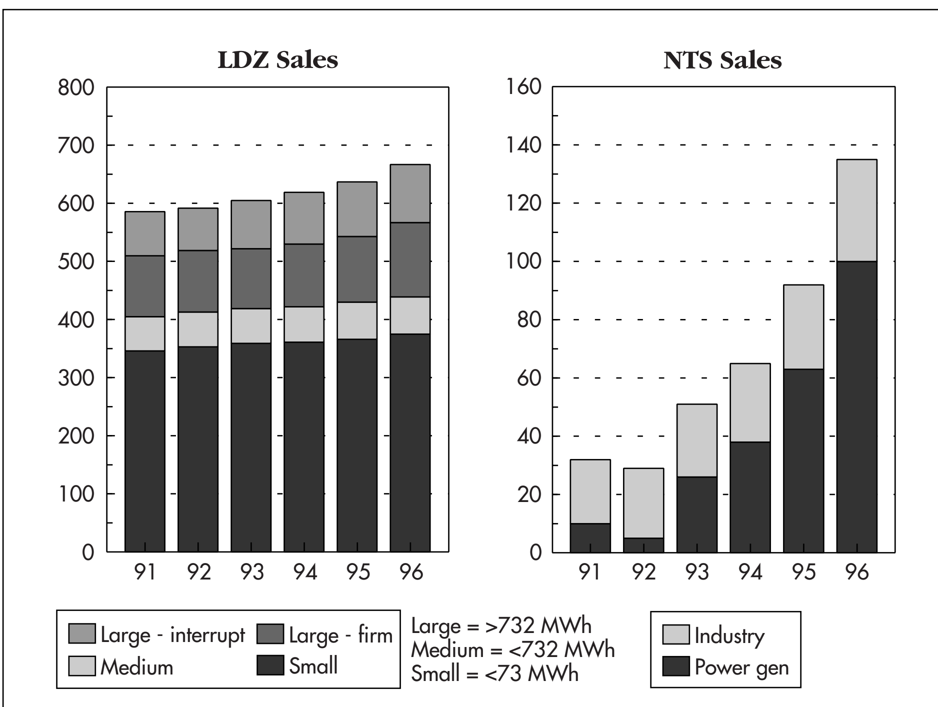

Source: IEA, based on *Wood-Mackenzie* and BG Transco data.

*Figure B-20*
**UK Gas Consumption by Sector, 1990 to 1997**
(GWh)




Source: DTI, *Energy Trends* (various issues)

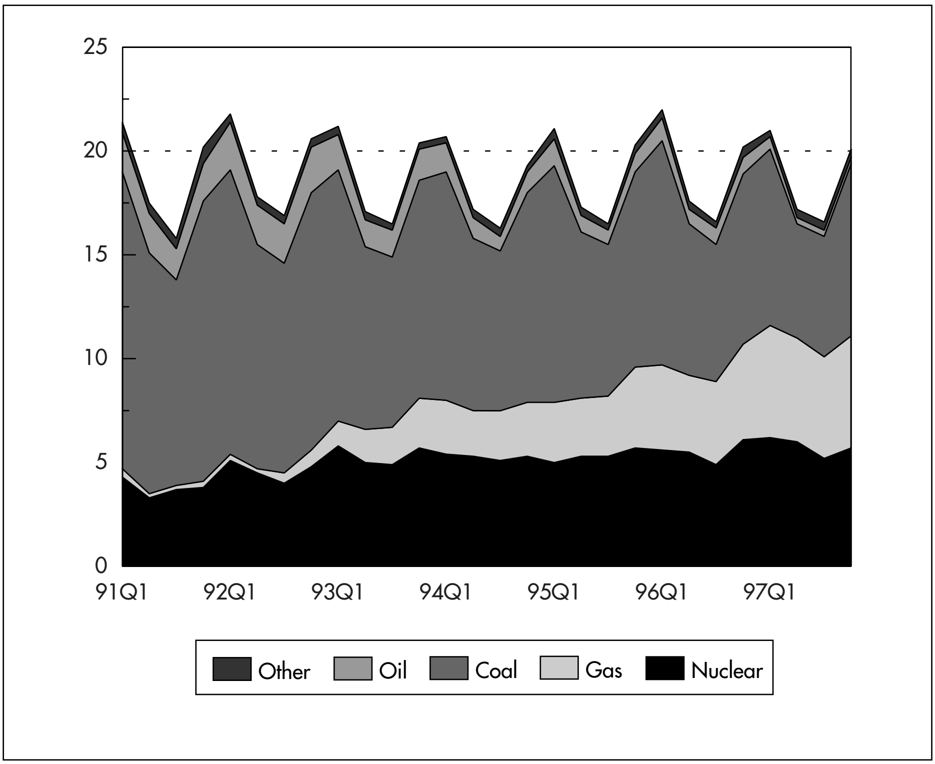
*Figure B-21*
**UK Gas Sales by Customer Category, 1991 to 1996**
(TWh, weather-adjusted)




Note: LDZ = Local Distribution Zone; NTS= National Transmission System
Source: MMC, *BG plc* (1997)

The biggest factor determining UK gas demand in the short term is weather, because of the importance of residential heating. Unseasonably low winter temperatures can significantly raise peak winter demand. The unpredictability of winter temperatures results in a significant degree of short-term uncertainty over peak daily demand, which has major implications for prices on the day-ahead and within-day markets (see below).

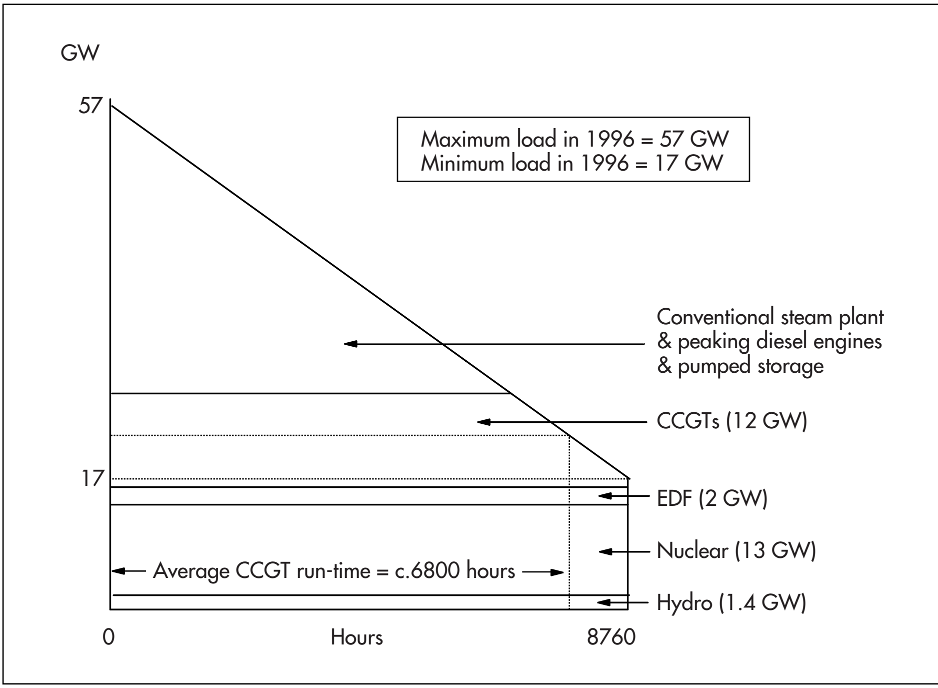
*Figure B-22*
**Fuel Use in Power Generation, 1991 to 1997**
(Mtoe)




Source: DTI, *Energy Trends* (various issues)

The overall load factor for the United Kingdom has increased in recent years due to the rapid increase in gas use in power generation (see Figure B-22) and the capture of some industrial end users of heavy fuel oil during summer (when gas prices can be very low). Most of the CCGTs, all of which have been commissioned since 1991, are run as baseload plant. Figure B-23 illustrates, in a simplified form, the indicative place of gas in the merit order based on actual bidding. Gas normally comes after hydropower, nuclear plant and imports of nuclear power from France. The average load factor of UK CCGTs is currently around 75% to 80%, or around 6 800 hours/year.

*Figure B-23*
**Simplified UK Electricity Load Duration Curve, 1996**




Note: This graph represents the indicative merit order for meeting UK load based on actual pool bidding; in practice, there would have been some overlap between different types of plant at the margin and baseload plant availability would not have been 100%.
Source: IEA analysis based on DTI data from *Energy Trends* (various issues)

# SHORT-RUN PRICE DETERMINATION

The distinctive characteristics of UK gas demand and supply — including a modest amount of storage and heavy reliance on production swing to meet seasonal load, as well as the pronounced seasonality of demand — have important implications for the determination of market prices in new contracts. Effective prices paid under existing term contracts are a function of the base price and the indexation formula (if any). At any given moment, the base price — or spot price for very short-term deals without indexation — for gas at any point along the supply chain is primarily a function of the overall balance of supply and demand and/or expectations of future changes in supply and demand fundamentals. As in all competitive gas markets, differences between bulk prices and prices to different end users for equivalent delivery periods are largely determined by differing transportation and storage costs, which in turn are a function of load factor, and volume and type of supply (firm or interruptible). Movements in gas prices are almost entirely due to shifts in the supply and demand balance and, on peak days, the market value of swing and storage.

## The Significance of Delivery Period

The interaction of supply and demand in the British gas market has tended to produce very pronounced fluctuations in prices. The mechanics of short-run price determination and the degree of price volatility are significantly different depending on the delivery period: very prompt, short-duration delivery periods are most prone to sharp price movements, while long-term contracts tend to be more stable:

- ***Long-term contracts:*** At any given moment, there is a market *base* price for long-term contracts covering delivery over a period of more than three years with a given indexation formula, swing and take-or-pay commitment. That base price is primarily a function of current market conditions, the market's expectation of how those conditions are likely to change in the future and the type of price indexation. The base price in long-term contracts with a significant element of gas-price indexation, not surprisingly, tends to match closely the prevailing price in the spot market for one-year forward delivery (discounting any seasonality in price)[47]. In long-term contracts without spot gas-price indexation, the market base price may be higher than prices in the prompt market if expectations are for demand and supply fundamentals to tighten over the long term. Thus, the market base price at the beginning of 1998 for long-term contracts to power generators was around 15 p/therm with oil price indexation and 16 - 16.5p/therm with pool-price indexation. This difference derived from a perception among producers that pool prices are likely to be weaker than gas prices over the medium to long term. The spot price for the remainder of the 1998 gas year (to end September) was under 14p/therm.

- ***Short- and mid-term forward delivery:*** The market price (spot or futures) for gas to be delivered over a future period is, as in any market, a function of expectations about the balance between supply and demand. In Britain, the key supply-side factors tend to be scheduled maintenance shutdowns and estimates of how much firm storage has been reserved by shippers; the key demand-side factor is seasonal weather patterns, particularly winter temperatures. Thus, the spot price at the beginning of 1998 was 17.8p/therm for first-quarter delivery, 11.7p/therm for the second quarter, 10.8p/therm for the third quarter and 13.7p/therm for the fourth quarter[48].

- ***Very prompt delivery:*** The importance of residential and commercial heating demand in total gas demand and the short-term volatility of winter temperatures results in acute volatility in prices on the day-ahead and within-day markets, including the flexibility market. Price determination on peak days is discussed below.

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47. In principle, if the market is broadly in equilibrium, a long-term contract without full spot-gas price indexation might be expected to be priced at a slight discount to the current spot market, since the producer or marketer is exposed to less price risk than with a series of short-term contracts. In practice, such a discount has not emerged in Britain.
48. *Petroleum Argus Gas Connections*.

## The Impact of Oversupply on Spot Prices Since 1994

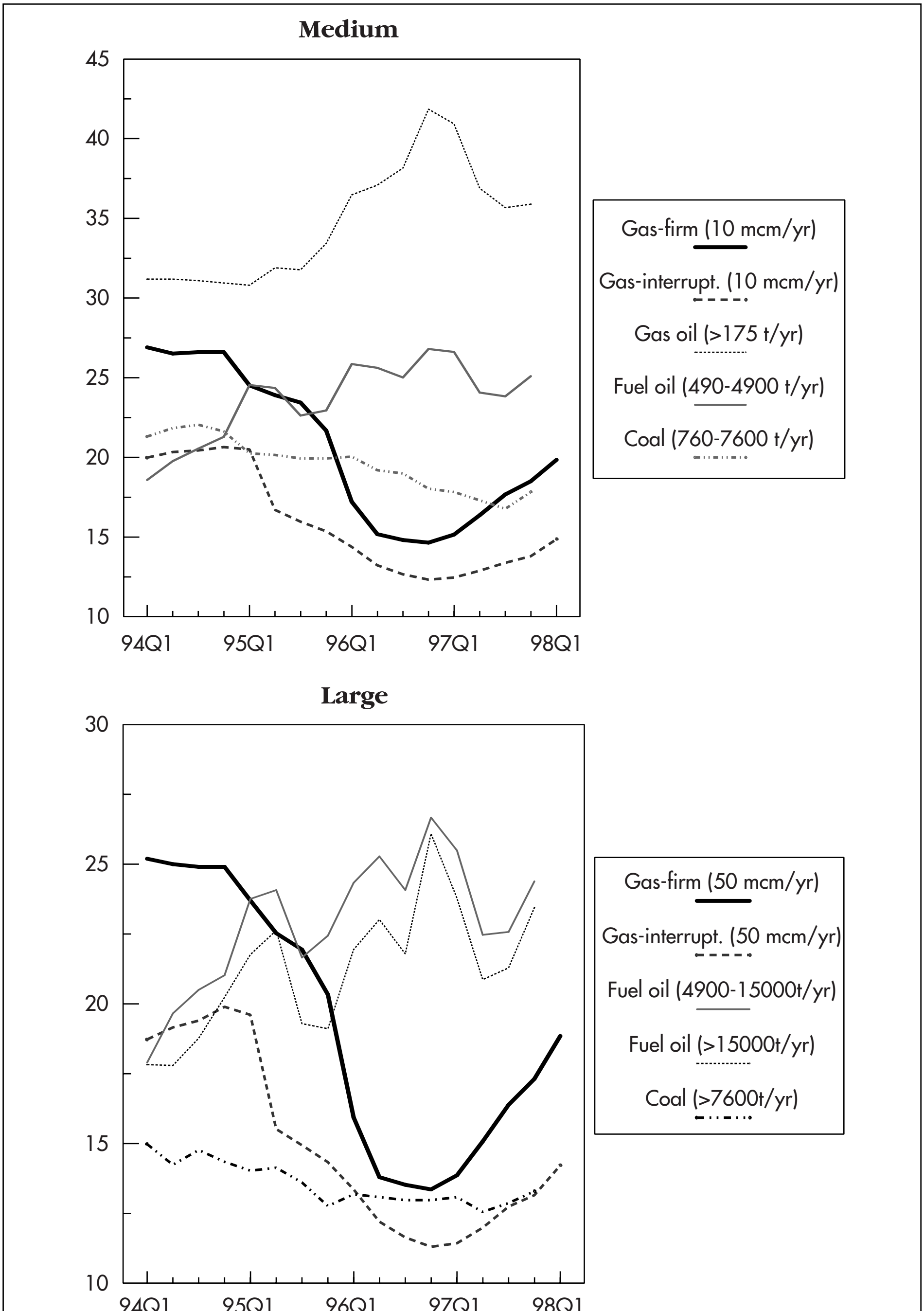
Since 1994, gas prices in the British market have been driven lower by the emergence of oversupply as production from a spate of new fields has outstripped the increase in demand, partly due to delays in commissioning new gas-fired power-generation capacity. Detailed information on contracted supplies is difficult to obtain because of commercial confidentiality, but industry estimates put the surplus of supply — defined as the annual contracted quantities (ACQ) over demand — at around 1 000 mmcfd (10 bcm/year) in 1996 and 1997[49] Some of this gas has been paid for but not lifted under take-or-pay contracts (mostly held by Centrica). This gas was "banked" for delivery at a later time, though much of it was released from contract in Centrica's recent contract renegotiations. Potential peak availability of gas has also outstripped peak demand. Total maximum potential supply at the beach and from storage amounted to around 18 mmcfd in winter 1997/8 compared to Transco's estimated 1-in-20 peak winter day[50] demand level of 14.8 mmcfd (not allowing for interruptions). Both the base prices in new contracts and the spot prices of short-term gas sales have come under downward pressure with the build-up of surplus volumes (see Figures B-9/10). In short, the market has become supply-driven.

Since 1994/5, market prices have effectively been determined by gas-to-gas competition. Interfuel competition has rarely been a factor in short-term gas-price determination. The oversupply of gas since that time has pushed gas prices to levels well below those of competing fuel prices. At present, virtually all gas end users with dual-firing capability are already using gas. Thus, a fall in prices has no significant short-term effect on gas demand. Figure B-24 shows that, since 1995, even firm gas prices have been well below the price of heavy fuel oil — the primary competing fuel — for medium and large industrial consumers. Since the beginning of 1996, interruptible-gas prices have been lower than coal prices to large industrial consumers. Similarly, in the power sector, spot-gas prices to CCGTs have been consistently below average coal prices, adjusted for differences in thermal efficiency[51] (see Figure B-25).

In principle, heavy-fuel-oil prices provide a ceiling for gas prices: were gas prices in new interruptible contracts to exceed oil prices to any significant extent, large industrial and commercial customers with dual-firing would postpone signing a new gas contract at the expiry of their existing contracts and switch to oil for as long as gas remained uncompetitive. This would gradually reduce demand for gas as increasing numbers of contracts expired, thereby alleviating the upward pressure on gas prices. In practice, this ceiling has not been tested since the emergence of competition in the British market.

49. See Wood Mackenzie, *North Sea Report* (July 1996).
50. Estimated peak daily load with a 5% probability of occurring.
51. There may, however, have been times when the cost of generation from imported coal at certain power stations located near to an import terminal was lower than that from spot gas.

*Figure B-24*
**Fuel Prices to Industry, 1st Quarter 1994 to 1st Quarter 1998**
(p/therm)

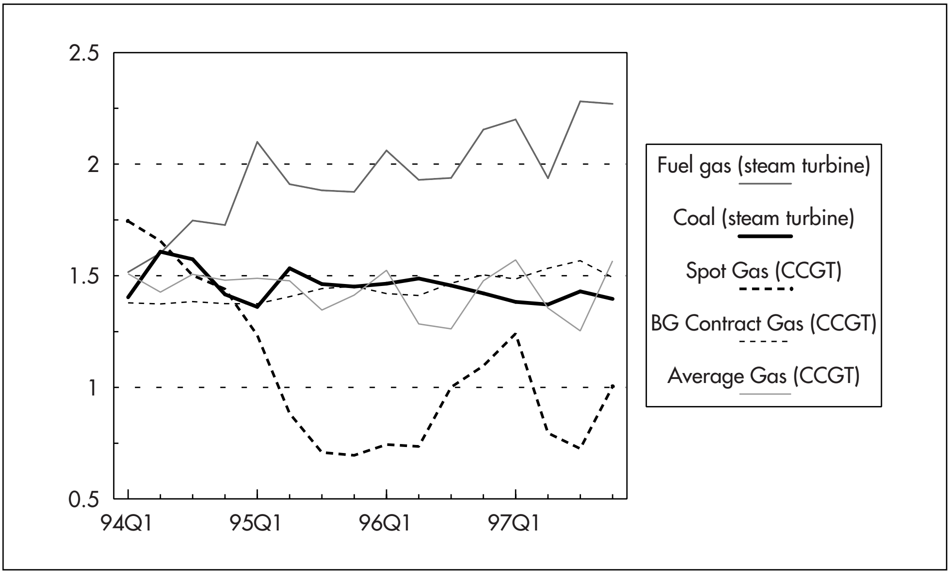



Source: DTI, *Energy Trends* (various issues)

*Figure B-25*

**Fuel Costs of Electricity Generated, 1st Quarter 1994 to 4th Quarter 1997**

(p/kWh)




Note: Assumes thermal efficiencies of 45% for gas and gas oil in CCGTs, and 37% for coal and oil in steam turbines (actual 1996 data).
Source: IEA, based on date from DTI, *Energy Trends* (various issues)

For all their volatility since 1994, spot prices have on several occasions fallen to around 8.5-9p/therm, but at no time have they fallen significantly below that level. Prices have fallen to this level in the last two summers (1995/6 and 1996/7). This effective floor price appears to be determined by supply-side factors. During the summer, gas deliverability has been considerably in excess of end-user demand even allowing for scheduled maintenance and purchases by shippers and the Top-Up Manager for injection into storage. There has been insufficient downside flexibility of demand to absorb all this surplus deliverability, since all dual-fired capacity is already been running on gas. Price elasticity of demand is extremely high at that point along the demand curve.

Although the short-run marginal costs of production are generally much lower than 9p/therm, North Sea producers are collectively unwilling to offer gas onto the spot market at less than this price. They prefer to leave the gas in the ground for production at a later date when they expect prices to be higher. The determination of this effective floor price is, in effect, based on expectations of future price levels as represented by forward spot prices and market base prices for long-term contracts without spot-gas-market-related indexation[52].

52. In a rational world, one would expect the marginal producer to set a minimum price which is equivalent to the net present value of the future revenue stream from the gas if produced at a later date, based on assumptions of future prices. However, we have found no evidence that producers regularly calculate such minimum prices in a systematic way.

## Price Seasonality

As in the United States, the British forward spot and futures markets show a price seasonality according to load variations. This reflects the additional cost to shippers of meeting higher winter demand — either by contracting for swing in beach contracts, booking storage or negotiating interruptible contracts with end users. BG Storage's rates for storage space and withdrawal capacity at each of its facilities are regulated by Ofgas, although secondary trading may take place at higher or lower prices[53]. Firm Rough storage — the only seasonal storage facility — has not been fully subscribed over the past three winters: in the most recent tender in April 1998, 51% of space and 36% of deliverability was reserved; remaining capacity will be sold on a first-come-first-served basis. Thus, the seasonal price variations in forward contracts tend to reflect closely the regulated price of that service. The cost of booking firm Rough storage for a shipper with no swing in its contracted gas supplies and a customer-load factor in line with the 45% national average amounts to around 3p/therm, which is close to the typical winter/summer price differential in the forward spot and futures markets averaged across the two seasons (see Figures B-10 and B-11).

In addition, the cost of firm Rough storage also sets an upper limit on the premia that shippers are prepared to pay for swing in beach contracts: BG Storage has calculated the premia for 10% swing for gas delivered at Bacton at 0.25p/therm for a 60-day full-cycling period[54] based on 1997/8 prices (see Table B-1). Only when Rough becomes oversubscribed at regulated prices might the premia for swing in beach contracts rise significantly above these levels. Under these circumstances, the market value of beach swing would set the marginal price of storage traded on the secondary market.

## Price Determination on Peak Days

Short-term price determination on peak winter days in Britain is primarily a function of the extent to which demand approaches peak system deliverability. Peak deliverability needs are met, in order of importance, from swing in beach contracts, storage and interruptions to industrial and power-generation customers (see Table B-2)[55]. In the future, the UK-Continent Interconnector and possibly voluntary load-shedding by power generators will provide additional means of meeting peak deliverability.

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53. For example, all Hornsea storage space and deliverability was sold to shippers in early autumn 1997 at the Ofgas approved price of £1.087/therm for deliverability; in subsequent secondary trading, deliverability was reportedly priced at around £2/therm.
54. Gas is completely withdrawn once over the period.
55. The relative importance of these different means of peak deliverability does not indicate relative long-run costs. Swing is probably the most expensive way in the long run of providing peak deliverability: prior to restructuring, British Gas imposed large swing obligations on North Sea producers in the absence of competitive pressures to seek less costly approaches.

*Table B-1*

**Cost of Providing Equivalent 10% Swing in Gas Purchase Contracts from Firm Rough Storage**

(p/therm on all gas delivered)

| Delivery point | 30 days duration* | 60 days duration* |
|---|---|---|
| NBP | 0.215 | 0.254 |
| Bacton | 0.212 | 0.251 |
| Easington/Theddlethorpe | 0.208 | 0.247 |
| Teesside | 0.203 | 0.242 |
| Barrow | 0.192 | 0.232 |
| St Fergus | 0.157 | 0.196 |

* Duration is the time required to empty reserved space, given reserved withdrawal capacity and assuming a constant withdrawal rate. A higher duration requires the shipper to book more storage space, but ensures that the service would remain effective throughout a more severe winter.

Note: Assumes one complete cycling of gas. Calculations based on 1997/8 prices.

Source: BG Storage, *Storage Services 1997/8* (1997).

*Table B-2*

**UK Supply and Demand Balancing, 1996/97**

| | Available | Percentage |
|---|---|---|
| *Deliverability (million therms/day)* | | |
| Storage*, of which | 38.0 | 33.6 |
| *Rough* | *15.6* | *13.8* |
| *Hornsea* | *6.4* | *5.7* |
| *LNG* | *16.0* | *14.1* |
| Power station interruptions | 9.4 | 8.3 |
| Industrial interruptions | 17.2 | 15.2 |
| Beach swing | 48.4 | 42.9 |
| Total | 112.9 | 100.0 |
| *Volumes (million therms)* | | |
| Storage, of which | 1 222.6 | 11.2 |
| *Rough* | *1 037.4* | *9.5* |
| *Hornsea* | *95.4* | *0.9* |
| *LNG* | *89.8* | *0.8* |
| Power station interruptions | 432.2 | 3.9 |
| Industrial interruptions** | 772.6 | 7.1 |
| Beach swing*** | 8 517.2 | 77.8 |
| Total | 10 935.6 | 100.0 |

Note: * Peak less average deliverability; ** Assumes maximum 45 days interruption; *** Assumes swing is available for 176 days.

Source: MMC, *BG plc* (1997)

A shipper makes arrangements ahead of time to meet peak-day demand by contracting for swing in their beach contracts, booking space in and firm deliverability from storage, and signing interruptible customers. If these arrangements are insufficient to meet actual peak winter demand, the shipper must rely on spot purchases on the day to meet any imbalances or pay financial penalties to Transco according to the prices established on the day in the flexibility market[56]. Since full introduction of the Network Code, the flexibility market has tended to lead pricing of gas on peak winter days, although most day-ahead and within-day gas is traded outside that market.

Flexibility-market rules and the limited sources of gas at peak have tended to lead to very high prices at times when load approaches system peak deliverability[57]. At such times, shippers who can supply additional volumes to the within-day spot and flexibility markets may bid in that gas on a difficult day at a very high price if the market perceives that within-day gas is in very short supply. The bid price, in this instance, is based not on the short-run marginal cost of obtaining gas from storage (once storage withdrawal capacity is booked, the cost of actual withdrawal is small[58]) but rather on the perceived value of the gas to shippers who are short of gas. This value increases with the likelihood of prices rising to the extremely high levels of the Top-Up storage bids. Thus, actual bid prices reflect the degree of risk that shippers will have to pay extremely high financial penalties for being out of balance. Ofgas believes that poor information flows, and possibly the exercise of market power by one or more participants, has also contributed to price spikes. Because of these problems, and the excessive prices that have resulted on some occasions, the regulator plans to invite bids for the operation of a new, screen-based within-day balancing market to replace the current flexibility market[59].

The price risk to shippers facing supply shortfalls on peak days explains the keen interest shown by shippers in leasing BG Storage's high-deliverability salt-cavity capacity at Hornsea (deliverability was completely sold out in the April 1998 tender). It also explains a recent decision by United Gas, the marketing affiliate of Utilicorp, to build a second salt cavern complex in Northwest England (to be commissioned by early 2000).

Interruptibility is playing an increasingly important role in peak-day balancing[60]. Most shippers occasionally impose interruptions on industrial customers within the terms of their contracts to balance their portfolios and avoid having to pay high flexibility-market prices for any supply shortfalls. Shippers are often reluctant,

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56. In some extreme cases, it may also be possible to negotiate interruptions with firm customers in return for financial compensation.
57. The so-called 85% rule under the Network Code, which provided for interruption to non-firm storage at times when demand reached 85% of the level of demand corresponding to a one-in-20 peak winter day (as determined by Transco), previously added to price volatility. The rule was eliminated in early 1998.
58. Less than 0.6p/therm for LNG and 0.2p/therm for Rough.
59. Ofgas, *An On-The-Day Commodity Market for the Gas Balancing Regime* (Consultation Paper, May 1998).
60. Total interruptions amounted to 3 190 million therms in 1995 and 3 530 million therms in 1996.

however, to make too frequent recourse to this option (even though they may be contractually within their rights to do so) in order to maintain good relations with their customers. Power stations have also been interrupted on a few occasions over the past two winters. Transco may impose interruptions on designated large end users in the event of network capacity constraints, particularly as demand approaches the estimated l-in-20 peak day, but these interruptions generally only account for a small proportion of the total over the winter season (10% in 1996/7 and 3% in 1997/8). Interruptible customers themselves have no automatic incentive to switch fuels at peak times, since they generally pay a fixed price competitive with competing fuels over a fixed contract period (usually one year).

There has been much discussion about the potential for arbitraging gas and electricity prices. This would involve switching gas between the power sector and the gas spot market according to price signals so as to maximise the value of contracted gas supplies, as in the United States. In principle, this could help to alleviate upward pressure on spot-gas prices on difficult days. There are, however, a number of rigidities that prevent such gas/electricity arbritrage in most cases:

- Most of the BG LTI contracts signed with CCGTs in the early 1990s expressly preclude the selling-on of gas. Thus, these stations run on gas even when the within-day spot market and flexibility-market prices are very high and where a spot sale would yield a higher return than generating power. A case has been brought before the European Court alleging that these contracts are anti-competitive.

- Most gas delivered to power stations under long-term contracts are covered by back-to-back power purchase agreements. If their contracts permitted selling on gas, power generators without dual-firing would have to cover their sales commitments with pool purchases, possibly at high prices. Those generators with dual-firing could cover those commitment by running on distillate or LPG, but the higher prices for these fuels would put a ceiling on profitable arbitraging.

- Generally, when spot-gas prices are high, pool prices are also high. As a result, there have been few occasions over the past couple of years for profitable arbitrage.

- Under power-pool rules, the generating plant has to be committed one day ahead. Often, high prices on the within-day spot and flexibility markets appear too late for generating plant to be withdrawn and the gas diverted to those markets. This is an issue being addressed in the UK Government's current review of pool pricing.

With gas use in power generation expected to increase steadily over the next few years, interfuel competition in this sector is likely to play an increasing role in gas price determination, particularly on peak days, for a number of reasons:

- With the imminent full liberalisation of the retail electricity market, electricity suppliers are showing increasing reluctance to sign long-term contracts without a high degree of pool-price indexation (to limit the risk that their power supplies may become uncompetitive). As a result, new CCGT power projects may increasingly be developed on a "merchanting" basis[61]. These plants would burn spot gas or supplies under medium-term spot-price-related contracts and sell the power at prevailing pool prices without back-to-back power sales agreements. The plants would only run when the "spark spread" is favourable, that is, when relative prices are such that the plant can make a profit. One CCGT, being built by Enron at Sutton Bridge, is expected to operate on this commercial basis under a "tolling" arrangement with Eastern. Given the likely thermal efficiency of this plant (in excess of 50%), recent spot-gas/power-pool price spreads would have allowed the plant to operate at baseload, although Enron expects the plant to run most often at mid-load.

- A proportion of existing coal capacity is expected to be converted to dual coal and gas-firing. For example, Eastern is converting its coal-fired Drakelow and Rugeley stations to dual-firing: how the plants will run will depend on relative fuel prices and emissions limits. A high proportion of the gas to be used is expected to be bought on a spot basis.

- The recent expiry of the government-backed five-year coal-supply contracts with the generators (National Power, PowerGen and Eastern). The lower prices being negotiated in the new contracts, reflecting the lower prices of imported coal, will increase coal versus gas competition in mid-load generation. Coal-fired plants would displace merchant gas-fired CCGT capacity as gas prices rise.

- Most new gas-fired plants are expected to be capable of also firing on distillate (or LPG), increasing the potential for shedding gas load at peak when gas prices rise above distillate prices and electricity prices are high enough to support distillate fuelling. Gas prices would have to rise to above about 30 p/therm for distillate to displace gas in dual-fired CCGTs at current distillate price levels.

## LONG-RUN PRICE DETERMINATION

In the long run, British gas prices should tend towards the long-run marginal cost of production from offshore fields (or imported gas supplies if and when the United Kingdom again becomes a net importer of gas) as long as the market is in equilibrium. Prices may be lower than long-run marginal costs if productive capacity is developed more rapidly than demand grows; similarly, a lack of investment in production capacity could lead to prices well in excess of long-run costs.

Experience has shown that North Sea supply is relatively inelastic over a wide range of prices. Much lower gas prices for new supplies since 1995 have had led to the postponement of some new field developments, including Viking FS, Olympus and Hunter. Output continues to rise, however, as other fields come onstream either as associated gas or to meet rising demand, particularly for power generation.

61. At the time of writing, the UK Government has imposed a moratorium on licensing of new gas-fired power stations while it reviews its policy concerning fuel diversification in power generation.

As shallow water Southern Basin reserves are depleted and exploration and development activity moves progressively northward into deeper water, production costs may rise. This may be at least partially offset by technology driven reductions in exploration and development costs. In addition, an increasing proportion of output is expected to come from combined oil/gas fields, where the economics of oil production alone may be sufficient for projects to proceed regardless of gas revenues.

The prospects for UK demand are, in turn, largely a function of the rate of growth of GDP and industrial activity, which in large part explains the recent strong growth in the residential, commercial and industrial sectors, and the economics of, together with government policy towards, gas-fired power generation.

## THE IMPACT OF THE INTERCONNECTOR

The 20 bcm/year Interconnector from Bacton to Zeebrugge in Belgium was due to come into service in October 1998. Its initial purpose is to provide an export outlet for surplus British gas, but it could eventually be used to import gas from the Continent. Initially, reverse flow will be 8.5 bcm/year, but this could be increased with further investment in compression.

The equity partners in the Interconnector and other companies who have leased capacity under long-term deals had by the beginning of 1998 signed eight long-term contracts, five with European gas utilities (Ruhrgas, Wingas, Thyssengas and Gaz de France), two with end users (a power station and chemical plant, both in the Netherlands) and one with a new independent gas distributor in the Netherlands (Entrade). These contracts could amount to about 12 bcm/year at peak, and 60% of total capacity. Key features of these deals are as follows:

- ***Contract length:*** Most contracts are though to be for 10 to 15 years supply, though at least one of the most recent deals is thought to be for only 7 years.

- ***Swing:*** Typically around 110%, which is common in European term-supply contracts, compared with 120-130% in recent British deals.

- ***Take-or-pay commitment:*** Around 90% in all the contracts, usually with some provision for carrying over to the following year any volumes not lifted under the minimum, as is common in Continental Europe.

- ***Price indexation:*** All contracts are indexed almost entirely on Rotterdam and/or German inland low-sulphur heavy-fuel-oil and gas-oil prices, in contrast to some recent British contracts which have significant power-pool price and PPI indexation.

- ***Price review (reopener) clause:*** It is thought that most if not all the contracts contain a price-reopener clause permitting the price to be renegotiated at regular intervals, usually every three years, to take account of changes in market conditions.

While spare capacity exists, additional sales through the Interconnector will be dependent on actual and expected prices in the British market relative to Continental markets. The possibility of additional exports will, nonetheless, continue to provide some support to British beach prices in long-term contracts. British beach prices have recently come into line with the level of netback market values to Bacton from export sales: in early 1998, forward prices rose to around 14.5 - 15p/therm but fell back with the surge in the value of Sterling against European currencies and the fall in oil prices (which will lead to lower effective border gas prices under long-term contracts with oil-price indexation). One would not expect British beach prices to fall below the level of netbacks from key European markets to Bacton for as long as British producers are able to gain access to those markets through the Interconnector. In addition, Continental buyers may seek to buy top-up purchases of gas for short delivery periods when British prices are particularly low, thus putting a floor under British spot prices. Because of their access to sizable storage, the major European gas utilities, which have ready access to transmission capacity from Zeebrugge, may play a major role in such spot trading, though power generators and large industrial end users could later participate in this trade, depending on their ease of access to the network[62].

While it is expected that gas will flow predominantly from Britain to the Continent in the first few years of operation, it is possible that flow could be reversed at times during the winter. Operational procedures for determining flow reversal will be decided before the commissioning of the line. Although regular flow reversal may not be possible, there will be interest on the part of contracted buyers and sellers to enter into swap deals when spot prices in the British market are significantly higher than the value of the gas on the Continent. Swap deals are most likely when temperatures are relatively lower in Britain than in Europe or when there is a disruption to North Sea production. The most obvious European source of gas to make up for lost British exports at these times is the Groningen field, with its large swing potential, and the two large storage facilities under construction close to Groningen, though additional costs would be incurred in bringing lower-calorific-value Groningen gas up to British quality. There may also be opportunities for Gaz de France to divert volumes from its large, though less flexible, seasonal storage capacity. The Belgian utility, Distrigaz, which is a shareholder in the Interconnector and the monopoly transmission company in Belgium (with under used LNG capacity at Zeebrugge), will also be well placed to take advantage of value differentials between the British and European markets.

## STRUCTURE OF AND LONG-TERM TRENDS IN END-USER GAS PRICES

Bulk-gas prices constitute a substantial cost element of final gas selling prices, although the proportion varies considerably across end-user customer categories.

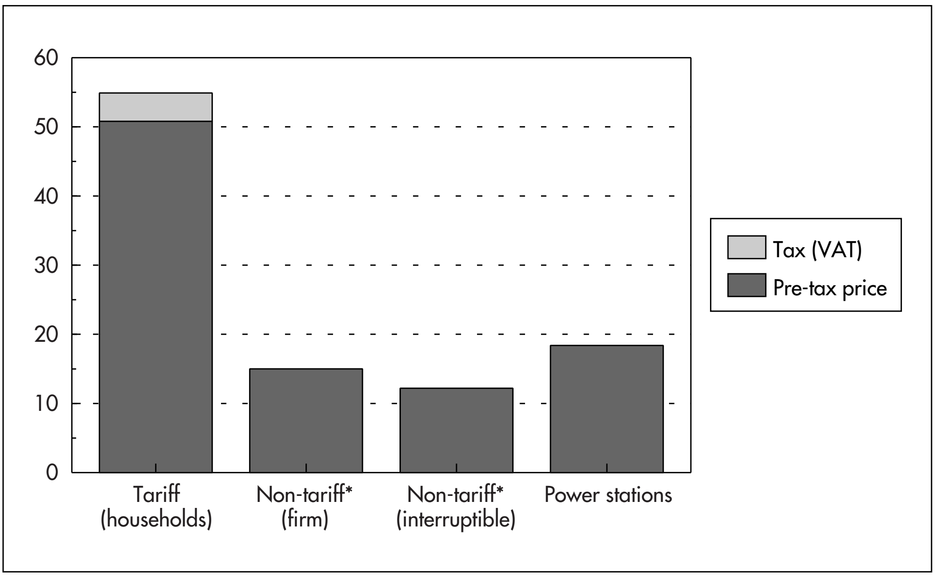
62. In fact, the first spot deal for delivery through the Interconnector involved two British shippers.

Prices to households (and small commercial users), which include 8% VAT, are by far the highest. Power-generation prices are substantially higher than firm and interruptible prices to industry, largely because of the proportion of gas sold to this sector under long-term contracts indexed to non-gas price elements. Most gas in industry is sold under short-term contracts, the prices of which have fallen sharply since 1995. Figure B-26 compares final selling prices across end-user categories.

*Figure B-26*

**Average UK Gas End-User Selling Prices by Sector, 1996**

(p/therm)



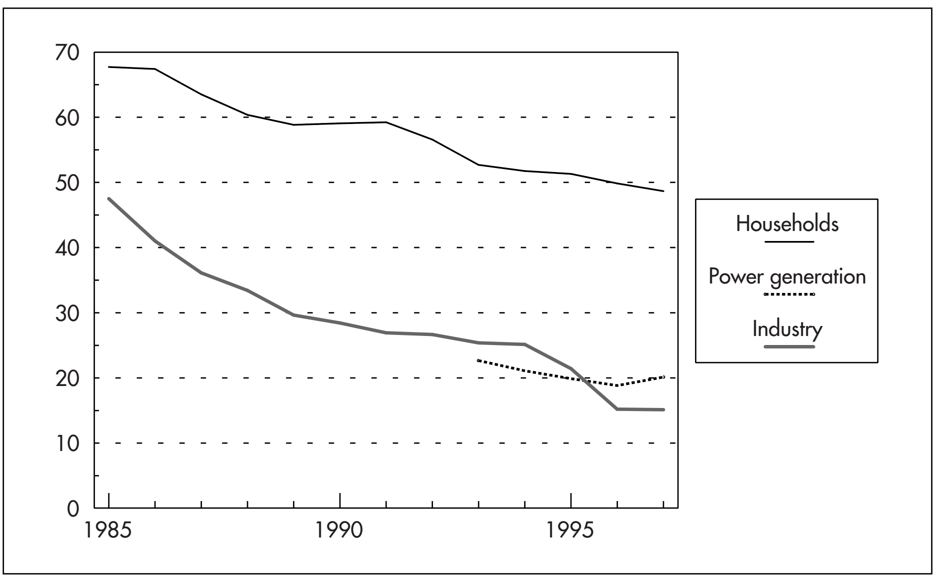

Source: DTI, *Digest of UK Energy Statistics* (1997)

Final selling prices include bulk gas cost and non-gas cost elements, which in turn include transportation (transmission and distribution), storage, customer service and net profits. Detailed information is not available on the breakdown of these costs among the different end-use customer categories on the basis of actual Transco charges. Information available from Centrica for 1995 shows that the gross margin — the difference between average sales revenue and average gas-purchase costs (including the gas levy) — was equivalent to 60% of average revenue of 42p/therm. Most non-gas costs (25.4p/therm) are accounted for by Transco transportation services, including metering — probably around 15p/therm. Storage charges are estimated to amount to around 0.5p/therm.

The share of the cost of gas at the beach in average total final selling prices is high compared to North America and other European countries. This is largely because of the low cost of high-pressure transmission per therm delivered. This is due in turn to the relatively short distances involved in moving gas from beach terminals to markets, the high degree of amortisation of the network and the embedded cost of swing in beach prices. The cost breakdown varies considerably across end-user categories. Transportation (predominantly local distribution) and storage costs are much higher in the household market because of low load factors. Gas purchase costs also vary according to swing: the true purchase costs for low load factor residential and commercial customers is thought to be around 2 to 3p/therm higher than for high load factor industrial customers[63].

Figure B-27 shows the long-term trend in real end-user prices (pre-tax) by consumer category. Prices to all sectors have fallen in real terms since the mid-1980s, although prices to power generators increased for the first time in 1997. Prices to industry have fallen most dramatically, from an average of almost 50p/therm in 1985 to around 15p/therm in today's money.

*Figure B-27*
**Real UK Gas Pre-Tax End-User Selling Prices, 1985-1997**
(1997 prices, p/therm)




Note: Gas sales to power generation were negligible before 1992. Prices deflated using GDP deflator
Source: IEA, *Energy Prices and Taxes.*

63. Precise estimates of the cost of swing under existing beach contracts are unavailable, but the cost of each 10% increment of swing in new beach contracts is thought to be around 0.25 to 0.3p/therm which is close to the comparative cost of storage. The capital cost to producers of installing swing is generally much higher.

# GLOSSARY

| | |
|---|---|
| AGA | American Gas Association. |
| Bcf | Billion cubic feet. |
| Bcf/d | Billion cubic feet per day. |
| Bcm | Billion cubic metres. |
| Beach/border price | Price of gas delivered to the beach or border terminal. |
| BG | British Gas; formerly a single public limited company. Since its demerger in 1997, British Gas is the trading name of Centrica in Great Britain and BG plc outside Great Britain. |
| BGT | British Gas Trading; subsidiary of Centrica, a UK gas company, formerly part of British Gas plc. |
| CCGT | Combined-cycle gas-turbine power station; often gas-fired. |
| Centrica | British gas company active in gas trading, offshore gas production and provision of energy services; part of British Gas until 1997. |
| Churning | Repeat spot trading of volumes of gas in the British market. |
| City gate | Point at which LDC takes delivery of gas; physical interface between transmission and local distribution systems. |
| Day-ahead gas | Gas for delivery on the day after the trade takes place. |
| DM | Daily metered or daily metering (for customer sites in Britain). |
| DOE | US Department of Energy; Federal department. |
| DTI | UK Department of Trade and Industry; government ministry. |
| EFP | Exchange of futures for physicals; standard contract used on NYMEX for arranging physical delivery of gas under a futures contract. |
| EIA | Energy Information Agency; part of US DOE. |
| ENC | East North Central region of United States. |

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| EU | European Union. |
| FERC | Federal Energy Regulatory Commission (United States); responsible for regulation of the US interstate oil and gas pipeline businesses. |
| Flat gas | Gas purchased with zero swing and 100% take-or-pay. |
| Gas-flow day | A period of 24 hours starting at 6 a.m. on one day and ending at 6 a.m. on the following day (Britain). |
| GWh | Gigawatt hours (unit of energy): watt × $10^9$. |
| IEA | International Energy Agency. |
| IPE | International Petroleum Exchange, located in London. |
| KCBT | Kansas City Board of Trade. |
| kWh | Kilowatt hour (unit of energy). |
| LDC | Local distribution company. |
| LDZ | Local Distribution Zones; the medium- and low-pressure system in Transco's network in Britain. |
| LNG | Liquefied natural gas. |
| Load factor | Average daily system throughput (or consumption) divided by peak daily throughput, expressed as a percentage. |
| MA | Middle Atlantic region of United States. |
| MBTU | Million British Thermal Units; unit of energy. |
| Mcf | Million cubic feet. |
| Mcf/d | Million cubic feet per day. |
| Mcm | Million cubic metres. |
| Mcm/d | Million cubic metres per day. |
| MMC | Monopolies and Mergers Commission; UK trade and competition authority. |
| Mtoe | Million tonnes of oil equivalent. |
| MW | Megawatt. |

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| NBP | National Balancing Point; a notional point on BG Transco's NTS where load is assumed to be balanced. |
| NDM | Non-daily metered/metering (for customer sites in Britain). |
| NE | New England region of United States. |
| NEB | National Energy Board (Canada); responsible for regulation of provincial oil and gas pipelines. |
| Network Code | The contractual regime for the management of the commercial and operational aspects of gas transportation in BG Transco's network in Britain. |
| NTS | National Transmission System (Britain). |
| NYMEX | New York Mercantile Exchange, where futures contracts for gas and other commodities are traded. |
| OECD | Organisation for Economic Cooperation and Development. |
| Ofgas | Office of Gas Regulation; the UK gas industry regulatory authority. |
| OFO | Operational Flow Order; an emergency order used by US pipelines to require shippers to inject or withdraw gas at specified points in the system at short notice to ensure system stability and safety. |
| OFT | Office of Fair Trading; UK competition authority. |
| OTC | Over-the-counter; off-exchange spot trade. |
| p | One penny; UK currency unit; £1= 100 pence. |
| PGT | Public Gas Transporter (Britain). |
| PPI | Producer price index. |
| Rough | Depleted offshore gas field in the United Kingdom used for seasonal storage. |
| RPI | Retail price index (United Kingdom). |
| SA | South Atlantic region of United States. |
| SAP | System Average Price (on the British flexibility market). |
| SFV | Straight fixed variable; US pipeline rate design mandated by FERC Order 636. |

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| SMP | System Marginal Price (on the British flexibility market) |
| Swing | A contractual commitment allowing a buyer to vary up to specified limits the amount of gas it can take at the wellhead, beach or border; the maximum daily contract quantity is usually expressed as a percentage of the annual contract quantity (100% equates to zero swing). |
| Tcf | Trillion cubic feet; one cubic foot × $10^{12}$. |
| TOP | Take-or-pay; a contractual commitment on the part of a buyer to take a minimum volume of gas, usually over a 12-month period, and expressed as a percentage of the annual contract quantity. |
| TPA | Third-party access; the right or possibility for a third party to make use of the transportation and related services of a pipeline company for a charge to move gas owned by the third party. |
| TPES | Total primary energy supply. |
| Transco | Subsidiary of BG plc (formerly part of British Gas); owns and operates most of the British gas network. |
| Within-day gas | Gas for delivery within the day on which the trade takes place. |
| WSC | West South Central region in United States. |
| WTI | West Texas Intermediate; US crude oil. |

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