Reliance on natural gas in European markets has increased strongly. Further increases, particularly in the power generation sector, are expected. The market structure has become more competitive but is still far removed from the degree of integration and competition prevailing in North America. In Europe, price discrimination remains noticeable. And pipeline access—a key to competitive price formation—is far from open. While open access is a necessary condition for greater competition in European gas markets, it is not sufficient. Other elements would need to be in place as well.

Les marchés européens dépendent de plus en plus fortement du gaz naturel. On prévoit que cette tendance va continuer à s'accroître, notamment dans le secteur de la production d'énergie. La structure du marché est devenue plus compétitive, mais elle est encore loin d'atteindre le degré d'intégration et de concurrence qui domine en Amérique du nord. Il est clair qu'en Europe les prix restent discriminatoires. De plus, l'accès aux gazoducs, clé de la formation de prix compétitifs, est loin de se libérer. Même si l'accès libre est une condition nécessaire à une plus grande concurrence sur les marchés européens, cela ne suffit pas. Il faudrait aussi que d'autres éléments se mettent en place.

Perspectives on Interfuel Competition in the European Natural Gas Market

G.C. WATKINS

Introduction

Over the past 25 years, reliance on natural gas as a source of energy in European markets has increased markedly, but not consistently, given price rigidity at various times. The main fuels displaced have been oil products and coal. The market structure has tended to become more competitive (especially in the United Kingdom), although still far removed from the degree of competition now prevailing in North America.

This paper has two main points of focus. The first is on end-user price relationships between natural gas and competing sources of energy in selected European markets: France, Germany, the United Kingdom, and Finland. The second point of focus is on what a more competitive European gas market may entail. To provide perspective, especially in the light of prospective changes in market structure, attention is paid to developments in North America.

The paper is organized in four main sections. Section I describes historical energy price relationships and energy market shares in Europe. It also looks at corresponding features in the US. Developments in North

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American natural gas markets are important, since they may provide a harbinger for Europe. Such developments are outlined in Section II. Prospects for the competitive evolution of European gas markets are discussed in Section III. Concluding remarks are made in Section IV. The historical price and market share data used are provided in the Appendix.

Not surprisingly, the review of energy prices in Europe and North America shows evidence of European natural gas price discrimination. The degree of penetration achieved by natural gas in North America indicates a substantial scope for further European gas market development. The North American natural gas market is, perhaps to an unusual extent, integrated and competitive. The key to any corresponding European development will be pipeline open access. But other market elements would need to be in place if competition were to become *de rigueur* in Europe.

I. Energy Prices and Market Shares – Historical Patterns

This section is descriptive. It looks at time series data on end-use energy prices and on market shares for selected European countries and regions in the United States. US patterns provide a useful point of reference. Detailed tables on end-user energy prices and on market shares are provided in the Appendix. The main emphasis below is on price ratios between different sources of energy by sector across countries, rather than on absolute prices. This approach bypasses currency conversions (local currencies can be used) and efficiency adjustments between different sources of energy.

The first set of tables in the Appendix relates to France, Germany, the United Kingdom, and Finland. The four European countries chosen have differing roles for natural gas. France imports about 90% of its gas from various sources, but gas accounts for only a relatively small share of final energy demand. In contrast, Germany is a natural gas–importing country where gas satisfies a significant portion of primary energy demand (around 20%). The United Kingdom is both a significant gas producer and consumer; gas accounts for nearly 30% of primary energy demand, of which imports satisfy only a small fraction. Finland is included to represent a gas-consuming Scandinavian country, one where gas meets only about 10% of energy demand, and all imports are from one source, the FSU.

The second set of tables in the Appendix relates to three States in the US: New York, Illinois, and California—representing the eastern and western seaboards, and a more central mid-West location.

To the extent feasible, end-user prices are shown by main market sector—industrial, residential, commercial and power generation. The main energy types identified are natural gas, electricity, light and heavy fuel oils, and coal. All prices were obtained from sources where they were already converted to tons of oil equivalence or BTU equivalence.[1] The period for which consistent price and market share data have been collected for Europe is 1978-92; the period covered in the US is longer, 1970-92.

Salient points that emerge from the price data are outlined below; Part A concerns Europe, part B concerns the US. The reader is referred to the Appendix for full details.

A. European Countries

EUROPEAN BACKGROUND

Almost all Western European countries consume gas. But consumption patterns vary greatly across countries. For example, Norwegian households consume little or no gas, while nearly all Dutch households use gas for space heating. Six major countries (Belgium, France, Germany, Italy, Holland, and the United Kingdom) account for about 75% of total Western European gas consumption. Gas mainly competes against light fuel oil (LFO) in residential markets, and against heavy fuel oil (HFO) and coal in industrial

1/ For Europe, the source was International Energy Agency *Energy Prices and Taxes*, various dates; for the United States, Energy Information Administration *State Energy Price and Expenditure Report 1993*.

markets.

The key feature of shifts in energy market shares in Western Europe in the 1970s and 1980s is the decline in the oil share, while natural gas and nuclear shares expanded. Most of the gas switching took place in the 1970s, and that for nuclear in the 1980s. In 1986, oil retrieved some market share from coal and natural gas in industrial markets, since when oil prices fell other prices did not adjust rapidly enough to prevent switching, especially by dual-fired facilities.

Technically, the natural gas transmission network in Europe is well integrated and covers most countries. A series of monopolies operate at national, regional, and local levels; there is little competition among alternative gas suppliers. Many member states have protectionist legislation that thwarts trade within the European Community. Long-term contracts are prevalent between producers and pipelines, with little or no third-party pipeline access. Corporate vertical integration is quite widespread. Imports satisfy about 30% of European Union consumption, and come mainly from three sources: Norway, Algeria, and the FSU.[2] Border prices are often contractually linked to prices of other fuels, usually LFO or HFO.

1. France

Residential prices of natural gas have been quite flat since the early 1980s. Electricity prices have shown a persistent tendency to rise, although increases have been modest since the mid-1980s. After 1986 (when LFO prices fell sharply) the ratio of natural gas prices to LFO has tended to fall, as has the ratio of natural gas to electricity prices. Market shares were quite stable in the 1980s, although those for petroleum products and coal have gradually fallen. The predominance of oil in the 1970s was abruptly squeezed in the 1980s.

Industrial energy prices have generally fallen since 1985. Natural gas prices appear closely aligned with HFO. Electricity and natural gas market shares tended to increase in the 1980s and early 1990s at the expense of oil, but the process has been slow and not uniform.

In the *power generation* sector, natural gas' small market share was almost extinguished after 1985. Nuclear is dominant, with 75% of the market in the early 1990s. Oil and coal shares have fallen steadily.

2. Germany

Residential electricity prices tended to rise over the entire 1978-92 period. Those for natural gas remained virtually constant to the mid-1980s, then declined before rising modestly after 1987. They have tracked LFO prices quite closely. The market shares of electricity and petroleum products have tended to fall; the share of natural gas has risen. Most recently, district heating technologies have begun to make inroads.

In the *industrial* sector, oil products and natural gas registered sharp price declines in 1986. Since then they have either been quite flat or showed some increases. In contrast, the price of coal has been quite stable, albeit with a modest upward trend. The ratio of natural gas to HFO prices normally exceeds unity by a noticeable margin, and has shown a tendency to increase since 1988. Natural gas prices are more closely related to LFO prices, with a ratio of about 0.75 common. The share of oil products in the industrial market has tended to fall, while electricity and gas have trended upward slowly. Coal shares have been quite stable.

In *power generation,* coal prices have been stable, while those for HFO and natural gas fell from 1985 to 1988. After 1986, both have been below coal prices. Consequently, since the mid-1980s the ratio of natural gas to coal prices has fallen from above to below unity. At the same time, natural gas prices have been about 20% higher than HFO prices after 1985. Coal market shares have remained relatively stable. Nuclear has made inroads, with oil and gas shares declining slowly.

2/ Algeria and the FSU have low marginal costs of production but substantial costs of transportation. Norway has higher costs of production but more modest transportation costs.

3. United Kingdom

Residential electricity prices rose rapidly up until 1982, flattened out and then resumed rising after 1987. Natural gas prices tended to rise over the entire period, but the trend was modest after the early 1980s. LFO prices dipped below natural gas prices in 1986, and remained below them thereafter—noticeably so. The ratio of natural gas to LFO prices registered abrupt increases in 1986 and 1988; in 1992, gas prices were about 25% above LFO. The ratio of natural gas to electricity prices showed a slight decline after the mid-1980s. Gas' market share gradually expanded over the 1978-92 period, mainly at the expense of coal. Market shares of electricity and petroleum products have been remarkably constant.

In the *industrial* sector, the relationship between natural gas and HFO prices switched in the mid-1980s. Before then, the HFO prices had exceeded gas; after, the contrary held, with HFO prices approaching those of coal, and natural gas prices exceeding HFO prices by as much as one-third.[3] However, the industrial aggregate masks two separate markets, one for firm gas competing against LFO, and interruptible gas competing against HFO.

The *power generation* sector shows a similar pattern to the industrial sector for the relationship between HFO and natural gas prices, although gas was used for peaking, where it mainly competed against LFO. In 1986, with the oil price crash, HFO prices fell precipitously to levels considerably below natural gas, where they have remained; whereas in the first half of the 1980s, HFO prices were generally above gas. From 1988 to 1990, coal prices have exceeded HFO prices—an unusual pattern. Coal shares have trended downward since 1980, and oil shares have been squeezed by nuclear sources. The fraction of the market captured by gas was small over the period of analysis. However, recently gas-fired CCGTs have enjoyed success competing against coal.[4]

3/ Caloghirou *et al.* (1995, p. 193) comment that in the industrial sector, natural gas prices can exceed fuel oil prices by 20-25% to account for non-price benefits offered by natural gas.

4/ The share of gas in UK power generation reached 13% in 1994, and continues to rise.

4. Finland

Residential energy price relationships in Finland show natural gas prices persistently below those of LFO. After plateauing in the mid-1980s, electricity prices have assumed a secular increase. The ratio of gas to electricity prices has been stable after 1986; the ratio of gas to LFO prices has tended to fall. Notwithstanding favorable prices for natural gas, natural gas market shares have remained trivial, while electricity shares have risen. The expansion of district heating at the expense of oil is noticeable after 1979 to the mid-1980s, after which its share stabilized.

In the *industrial* sector, natural gas prices have tracked HFO prices closely: the ratio between the two straddles unity throughout the period. Coal prices are substantially below either fuel. The ratio of natural gas prices to LFO has remained relatively stable in the 0.5 to 0.7 range.

In *power generation*, gas' share now approaches 10%. HFO prices have consistently exceeded coal, and by a considerable margin. Most of this market is served by coal.

The Position of Gas in 1992

European price relationships in 1992 by country and market sector are highlighted in the upper panel of Table I-1. The ratio of natural gas to oil product prices is comfortably above unity in the residential and industrial sectors for all countries, with the exception of Finland. The substantial gap in energy equivalent terms between electricity and gas prices—which holds for all countries—reflects the efficiency of electricity and its employment in distinctive end uses.

European *market shares* are highlighted in the upper panel of Table I-2. The share of gas in industrial markets is at similar levels in the UK, France, and Germany, while in power generation its role is minor. Penetration by gas in the UK residential market at greater than 60% is at North American levels; penetration in France and Germany is at about half the

Table I-1: Natural Gas, Oil, Electricity, and Coal Relative Price Ratios, 1992, US and Europe

Europe

	United Kingdom			Germany			France			Finland		
	G/O	G/E	G/C	G/O	G/E	G/C	G/O	G/E	G/C	G/O	G/E	G/C
Industry	1.51	—	1.44	1.63	—	0.78	1.38	—	1.20	0.96	—	1.57
Power Generation	1.35	na	1.21	1.31	na	0.79		na	—		na	—
Residential	1.50	0.25		1.52	0.25		1.22	0.31		0.50	0.16	

United States

	New York			California			Illinois		
	G/O	G/E	G/C	G/O	G/E	G/C	G/O	G/E	G/C
Industry	1.66	0.25	2.75	1.58	0.16	1.95	1.32	0.23	2.32
Commercial	0.97	0.18		0.83	0.17		0.97	0.20	
Power Generation	0.92		1.62	1.25			0.78		1.27
Residential	0.88	0.20		0.45	0.18		0.68	0.17	

KEY: G/O–Natural Gas/Oil; G/E–Natural Gas/Electricity; G/C–Natural Gas/Coal

Notes:
No UK 1992 data for power generation sector; G/O ratio is for 1989, G/C for 1993.
No relative price data available for France and Finland power generation sector.
All residential sector oil price ratios based on average oil product price for residential sector (LFO, LPG and kerosene).
All commercial sector oil price ratios are based on LFO.
All industrial and power generation sector oil price ratios are based on heavy fuel oil.

Source of prices: for Europe, International Energy Agency *Energy Prices and Taxes*, various dates; for the United States, Energy Information Administration *State Energy Price and Expenditure Report 1993.*

level of the UK's.

Variations in patterns between countries also reflect different policies. German pricing policy, Gjelsvik and Olsen (1989) suggest, has been one of a non-discriminating monopolist, squeezing all consumers to the same level. French policy has discriminated against households and smaller users, while UK policy has favored smaller consumers.

B. United States

US BACKGROUND

Natural gas use is widespread in the US, currently approaching 25% of primary energy demand. Most of the gas is supplied from domestic sources—especially from the southwest (Louisiana, Texas, Oklahoma, and Arkansas). But over the past few years imports from Canada have risen quite sharply and now satisfy close to 15% of US demand. Small amounts of US gas are exported to Mexico.

The production sector of the US gas industry is characterized by a very large number of field producers ranging greatly in size. By any measure, the degree of ownership concentration is small in virtually all regions (except Alaska). About 80 pipelines cross state boundaries, with 20 major pipelines transporting over 80% of US supplies (Doane and Spulber, 1994). Many local distribution companies (LDCs) are served by more than one pipeline. LDCs transport and distribute gas to residential, commercial, and industrial customers and generally operate as monopolies subject to cost-of-service regulation.

The US gas industry has seen a major reorganization, culminating in the Federal Energy Regulatory Commission (FERC) Order #636 requiring pipelines to separate gas sales from transportation activities. Such "unbundling" mandated open access to pipeline transportation for gas producers and consumers (also see Section II).

The price and market data discussed below extend back to 1970, covering a period of increasing and quite exotic regulation to one of

Table I-2: Fuel Shares by Country (Europe) or State (US), 1992, by Sector (%)

	Europe											
	United Kingdom						Germany					
	Gas	Oil	Elect. /Nuc.[1]	Coal	Hyd. /Geo.	Other	Gas	Oil	Elect. /Nuc.	Coal	Hyd. /Geo.	Other
Industry	26	33	21	19		0	23	31	23	21		2
Power Generation	3	9	24	62	2	0	6	2	30	57	3	1
Residential	63	7	21	8		0	30	38	18	7		7
	France						Finland					
	Gas	Oil	Elect. /Nuc.	Coal	Hyd. /Geo.	Other	Gas	Oil	Elect. /Nuc.	Coal	Hyd. /Geo.	Other
Industry	24	36	22	16		1	14	17	29	10		30
Power Generation	1	2	74	8		15	9	2	34	14	26	15
Residential	34	8	39	6		14	1	40	25	0		34

	United States											
	New York						California					
	Gas	Oil	Elect. /Nuc.	Coal	Hyd. /Geo.	Other	Gas	Oil	Elect. /Nuc.	Coal	Hyd. /Geo.	Other
Industry	41	11	28	19		0	47	36	13	4		0
Commercial	37	31	32			0	48	2	49			0
Power Generation	18	15	21	21	25	0	42	0	27		30	0
Residential	55	27	19			0	66	3	31			0
	Illinois											
	Gas	Oil	Elect. /Nuc.	Coal	Hyd. /Geo.	Other						
Industry	45	12	21	22		0						
Commercial	57	4	38	1		0						
Power Generation	1	1	58	40	0	0						
Residential	79	3	18	0		0						

1/ Key: Elect./Nuc – Electricity (Ind., Com., Resid. sectors)/Nuclear (Pwr. Gen. sector); Hyd./Geo. – Hydro/Geothermal; Other – District Heat, Geothermal non-Pwr. Gen., Wood, Other Solids.

Notes: Percentages may not sum to 100% due to rounding. Oil product shares for all sectors based on total oil product consumption plus LPG.

Sources: US: DOE/EIA *State Energy Data Report*, 1992, Consumption Estimates. Europe: IEA Statistics, *Energy Balances of OECD Countries*, 1980-1989 and 1976-1980.

increasing deregulation and greater competition.

1. New York State

In the *residential* sector, the ratio of natural gas to LFO prices has fluctuated quite widely, but, with the exception of one year, has always been less than unity. The ratio of the price of natural gas to electricity has been relatively stable, especially in the 1990s. As would be expected, the shares of the market served by natural gas have tended to rise over time, at the expense of LFO. The *commercial* sector shows much the same picture as the residential sector.

In the *industrial* sector, the ratio of natural gas to coal prices increased strongly to the early 1980s, but stabilized thereafter. The ratio of natural gas to HFO prices has tended to rise; that for gas to electricity prices has been quite stable. The overall share of coal and oil in the

market has fallen; gas and electricity shares have risen.

In the *power generation* market, the price of natural gas relative to nuclear[5] rose strongly throughout the 1970s and up to 1983. Thereafter it fell dramatically until 1986 and has remained flat since then. The ratio of natural gas to oil prices has been quite stable since 1980; the ratio of natural gas to coal prices has trended downwards since the early 1980s. The market shares of various generation feedstocks have fluctuated markedly. The share of hydro—mainly from Canada—has typically approximated 30% of the market. The share of nuclear generation has tended to expand throughout. The share of natural gas declined steadily in the first half of the 1970s, and gas was pretty well eliminated as a source in 1977 and 1978. But in the 1980s, gas has made a strong recovery and gas-fired plants now serve about 15% of the market. The oil share has been squeezed since the late 1970s.

2. Illinois

In the *residential* sector, the ratio of natural gas to LFO prices has remained comfortably under unity in all years, while the ratio of natural gas to electricity prices trended upwards modestly in the latter half of the 1970s; in the 1990s it has been quite flat. Not surprisingly, the share of the market served by oil has shrunk noticeably, while electricity and gas shares have risen, with gas predominant at close to 80% of the market in 1992. The *commercial* sector displays much the same pattern as the residential.

The *industrial* sector shows quite flat gas-to-electricity price ratios after 1980, while natural gas-to-HFO ratios have been erratic; gas-to-coal price ratios showed no trend in the 1980s, after rising strongly in the 1970s. The market share of electricity has gradually risen, the oil share has contracted, and the shares of natural gas and coal have been fairly stable.

For *power generation*, the ratio of natural gas to coal prices has been in excess of unity for most of the period. The ratio of natural gas to HFO prices was below unity throughout. The share of gas in power generation, which was around 18% in 1970, dwindled to negligible proportions by the 1980s; oil-fired generation is also small. In 1991, virtually all power was generated from coal and nuclear, with nuclear predominant.

3. California

In the *residential* sector, the ratio of natural gas to electricity prices increased from the late 1970s to the mid-1980s, but subsequently has tended to fall. The ratio of natural gas to oil prices has trended upwards since the early 1970s (with a hump in 1985). The share of the market served by oil has been minor, with no trend. That served by gas, while dominant, has tended to fall, while the share of electricity has risen.

In the *industrial* sector, the ratio of natural gas to coal prices has fluctuated widely, but has been more stable of late. The ratio of natural gas to HFO prices has shown an upward trend since 1973, while the ratio of gas to electricity prices has been quite stable. The market share of oil rose until the mid-1980s, then compressed before recovering in 1992. The swings in the share of gas tended to mirror those of oil.

In *power generation*, the ratio of natural gas to oil prices has been quite stable since the late 1970s. The ratio of natural gas prices to nuclear feedstocks fell dramatically from the mid-1970s to the mid-1980s, but has risen of late. The share of power generation served by oil, which was dominant in the mid-1970s, has fallen dramatically.

The Position of Gas in 1992

For the three selected States, price relationships in 1992 for natural gas are brought together in the lower panel of Table I-1. Industrial natural gas prices in all three states exceed HFO by a substantial wedge, but residential prices are below LFO. *A priori*, this apparent absence of price discrimination indicates competitive gas price formation.

The States' market shares are shown in the

5/ Nuclear prices represent the cost of uranium plus other input costs.

lower panel of Table I-2. The market share held by gas in the east and west coast residential, commercial, and industrial markets is substantial, and the role of gas in power generation is noticeable, especially in California. Illinois shows heavy reliance on gas, apart from power generation.

C. Pricing Relationships and Market Shares Compared: Europe and the US

As discussed, Table I-1 provides a snapshot of price relationships among different energy sources between Europe and the US for the most recent year for which consistent data were available for both areas, namely 1992. The main contrast is the residential gas price relationships to oil products, compared with those for industry. The residential gas-to-oil product ratios in excess of unity in Europe (excepting Finland) contrast with those below unity in the US, while those for industry are similar and substantially above unity.[6] This pattern of price discrimination among market sectors in Europe is consistent with a less competitive European gas market.

Table I-2, on market shares, shows the much greater penetration by natural gas in the more mature US market. Such penetration indicates the noticeable scope for additional reliance on gas in European markets.

Statistical analysis of European end-use energy prices (1978-1992) has revealed non-systematic price fluctuations, lack of long term links among oil product are natural gas prices, and little evidence of directional causality between them. What evidence of causality did emerge was pretty well confined to oil causing gas prices, not vice versa. In the US (1970-1992), there was some evidence of statistical regularity but little of long-term relationships between oil and gas prices—which is not surprising given the quite different price regimes that held in the US over the period of analysis. Evidence on causality between oil and gas prices was murky, with bi-directionality (feedbacks). The US results are what might be expected as a more competitive regime took hold (see Watkins, 1995).

6/ Recall that these ratios are for prices expressed in thermal equivalence.

II. North American Natural Gas Market Developments

US natural gas pipelines—subject to cost-of-service regulation—traditionally purchased and then resold virtually all the gas they transported to the point of exit, providing a single, bundled service. Purchase contracts with field producers were normally long term (20 or so years). The pipelines resold the gas to LDCs, also on a long-term basis. Indeed, under regulation pipelines had to demonstrate sufficient reserves under long-term purchase contracts to cover sales contracts, and to operate the lines at full capacity.

A. Salient Regulatory Actions

Regulatory actions culminating in open pipeline access commenced with the Natural Gas Policy Act (NGPA) of 1978, which deregulated certain wellhead prices. Around this time, in both the US and Canada, pipelines contracted for more gas supplies in a false anticipation of future shortages. Costs were recovered through minimum bill contracts with Local Distribution Companies (LDCs), combined with cost-of-service regulation. Take-or-pay (TOP) contracts bound pipelines to take delivery of gas at prices above resale market levels, given the averaging of regulated field price tiers. Contract disputes proliferated as pipelines sought to avoid losses resulting from TOP obligations.

A spot market for gas supplies emerged in late 1983, supplied initially by the refused takes of pipelines. Take-or-pay obligations were eased around this time by allowing merchant pipelines to pass along the costs of contract buy-outs. In 1979 some consumers were allowed to purchase directly from producers and to purchase transmission services from the interstate pipelines. This was the thin end of the wedge to open pipeline access.

A major step toward unbundling pipeline operations was taken by FERC in 1985 with Order #436, which allowed pipelines to be-

come open access transporters for gas bought directly by consumers from producers (voluntary open access). FERC Order #500 in 1987 offered blanket certificates for transportation if the pipeline company allowed all customers access. Pipelines were allowed to reduce rates in selected markets. LDCs were permitted to convert contract demand volumes between the pipeline and the LDC at the city gate to firm transportation volumes.

In many respects the culmination of the deregulation process was FERC Order #636 in 1992, which *mandated* separation by pipelines of the merchant function from transportation. This measure was the final regulatory initiative to make interstate pipelines simply providers of transportation services for producers and consumers. It also did some other things, as mentioned below.

B. Key Features of North American Deregulated Gas Market

Open pipeline access has been the crucible for the emergence of a competitive natural gas market in North America. In terms of how a pipeline operates, the distinction between pipeline common and contract carriage is important. Common carriage obliges a pipeline to provide transportation services for any party presenting gas to it. Often oil pipelines in North America are common carriers, while natural gas pipelines are open access contract carriers. Access is available as a first come-first served basis for all customers willing to pay the tariff.

Open access has encouraged the unbundling of services and the pricing of each function, such as gas gathering, gas treatment, compression, transmission, storage and sales. Previously, as merchants, pipelines had managed these activities. Deregulation has also seen the emergence of new middlemen (gas brokers and marketers) to arrange transactions.

Order #636 permits holders of firm capacity to trade excess capacity through Electric Bulletin Boards (EBBs) operated by pipelines. EBBs provide shippers with information about the availability of service on their systems—both capacity released and capacity directly available. Uniform standards for the provision of information have been encouraged.[7] The EBBs are part of a growing reliance on electronic communication and disclosure.[8]

Price transparency is now well established in North America. Price data are disseminated on a daily, weekly, monthly and annual basis by several sources, and there is legislative backing. Pipeline "guides" provide all manner of information on origin and delivery points, interconnections, rates and services.

Another aspect of the emerging competitive market in North America is the increased provision and reliance on natural gas storage services. Initially after FERC Order #436, limited access to storage restricted the effectiveness of pipeline open access. FERC Order #636 mandated changes aimed specifically at providing storage access and the unbundling of storage services.[9]

The unbundling of the merchant pipelines' role to one of providing just transportation services has shifted supply responsibility to LDCs. Hence the suitability of LDCs' gas supply portfolios has become important. Most LDCs' portfolios range from long-term firm contracts (one year or more), spot contracts and winter-only contracts. The majority of the contracts are long-term, but spot supplies can account for up to 30% of the total.[10]

A recent feature of US gas markets has been a decline in the share of US gas consumption served by spot markets to about 40% in 1994 (from 70% in 1988). Beforehand, in the US (and in Canada) open access transportation led to greater volumes of spot market trading—partly at the expense of pipeline system gas sales under long-term contracts. A new wave

7/ For details on the type of information available, see AGA *Gas Energy Review*, August 1994.

8/ Morris Adelman has reminded me that provision of such information would have been difficult in earlier decades without developments in information technology.

9/ On the changing role of storage in the United States, see AGA *Gas Energy Review*, March 1994. Also, see D.F. Santa, *AGA Gas Energy Review*, June 1994, p. 25.

10/ For some analysis of LDC supply portfolios, see AGA *Gas Energy Review*, November 1994.

of market mechanics has evolved, including trading of gas futures and options on the New York Mercantile Exchange (NYMEX) and many derivative financial price risk management tools, such as swaps. In the case of LDCs, possible applications of derivative instruments could include fixing forward gas bills for a season or number of years, a fixed ceiling on gas prices for cooling customers, and in NGV market a fixed discount between gas and gasoline prices.[11]

Pipeline tariff setting in the US was markedly affected by FERC Order #436, which enabled open access pipeline tariffs to be discounted from maximum sales resulting from cost-of-service applications. A menu of tariffs has emerged. Currently, FERC is also considering alternatives to cost-of-service regulation, including the use of price caps and automatic indexing.

Efficiency in the use of pipeline capacity requires flexibility in its release. Hence the importance of the creation of a secondary market for trading surplus capacity rights. This market is still at a relatively inactive stage of development. But in late 1993 about 10% of firm pipeline capacity demand was held by replacement shippers (Santa, 1994, p. 23).

Market hubs have been crucial in the restructuring of the North American gas market. A hub is an "arena" where pipelines interconnect and there is the ability to interchange gas. Such hubs provide a meeting place for many buyers and sellers to transact business, cutting transaction costs, yielding more options, and providing price transparency. In some cases hubs have been set up by LDCs—of which the first has been at Chicago (santa, 1994, p. 25).

It has been suggested that an unfinished item of business in the process of deregulation is the creation of transportation property rights (De Vany and Walls (1994)). Here the pipeline would become the supplier of transportation rights, not transport *per se*. In contrast to FERC Order #636, unused capacity would revert to the holder of the rights, not to the pipeline itself. Present holders of transportation contracts do not own a property right, only a claim on transportation for the duration of their contract. Restrictions on the purchase and sale of transportation capacity and on open access LDC transportation are the remaining barriers to a fully competitive transportation market.

C. Evidence on Competitive Market Status

Some research studies have emerged on US market structure. Doane and Spulber (1994) have looked at how open access has affected the geographical scope of the spot market. Statistical tests revealed that open access has by and large integrated regional wellhead markets into a national competitive natural gas market. At the same time the introduction of competitive buying and selling of gas at the wellhead through open access has diminished incentives to undertake long-term contracts.

Another study on the degree of natural gas market integration is De Vany and Walls (1993). Open access was found to provide the link for arbitrage of varying prices over different points of the network. Increasingly, any demand point was allowed to access gas from any supply point. Empirical analysis revealed much stronger gas market integration between 1987 and 1991. In particular, around 1987 only 46% of market prices for which price series were available were found to be closely linked. By 1991, this proportion had reached 66%.

Later work by Walls (1994) found the natural gas production sector prices strongly integrated. But markets between the field and city markets were less integrated. City markets which adopted some form of bypass and open access at the local level are more strongly integrated with field markets. The largest benefits of open access have accrued to downstream markets with high volume pipeline connections to the largely integrated network of producing fields. Chicago and California are typical of city markets where natural gas prices closely follow field prices.

De Vany and Walls sum up their work thus: the industry has become almost perfectly contestable at the wellhead and in transportation, with spot prices at 50 or so widely separated

11/ See discussion by B. Schlesinger and Associates, AGA *Gas Energy Review*, December 1994.

points following one and other so closely that they represent one market. On average, there are no arbitrage opportunities. City gate prices track field and pooling area prices. Brokers now buy and sell gas over the entire pipeline network, even without uninterruptible transmission rights. Pooling points (hubs) are very tightly integrated with production markets. Transport trading makes it possible to enter and exit a market quickly without making irreversible commitments. Hence the "hit and run" entry of contestable market theory has been put in place by gas markets by allowing gas and interruptible transportation to be actively traded among a variety of participants (De Vany and Walls, 1994).

In short, the North American natural gas market now displays many of the key criteria of competitive markets: many sellers; many buyers; the ability to link buyers and sellers; an absence of arbitrage opportunities, price transparency, and relative freedom of entry and exit.[12] This is not the case in Europe at present, to which I now turn.

III. Competition and European Gas Market Evolution

The outlook for natural gas in Europe is seen as buoyant. The attraction of natural gas as an efficient generator of power, as a (relatively) environmentally benign energy source and as a viable replacement for coal and oil leads to expectations of 50-70% increases in consumption over 20 years (Rissanen, 1992).[13] In contrast, more modest growth is expected in the mature US market, with about a 20% increase mooted, 1994 to 2010 (AGA *Gas Energy Review*, March 1995).

The intention of current European Commission (EC) policy, as revealed by draft directives, is to favor all those seemingly nice, liberal causes such as harmony of taxation, price transparency, grid interconnections, unbundling of production, transmission and distribution activities, and open pipeline access. In short, the EC policy is one of encouraging the evolution of a competitive market for gas of the kind that has emerged in North America.

Yet overhanging all these sentiments—however fine—is the principle of subsidiarity. Although the European Commission can define the framework, the member states can still opt for the system best suited to them. But one advantage Europe has over North America if a more competitive market structure were to evolve is that it does not have to overcome a past legacy of detailed regulation from the wellhead to the burner tip.

The discussion below looks at many of the features of competitive market structures that would need to emerge—or are emerging—if the European gas industry were to rely more heavily on competitive price formation (Part A). Alternative competitive exchange systems are discussed in Part B. Part C looks at the few estimates that have been made of gains from competition in Europe. The role of gas in power generation—so important to further market penetration by natural gas—is discussed in Part D.

A. Competitive Markets, Open Access and the Like

Abolition of entry barriers is a necessary condition to introduce so-called "gas on gas" competition. Such competition can be viewed in two dimensions. One is in terms of entry by rival pipelines in a market. However, this requires a large-scale, mature market. The second dimension, one more pervasive in the context of promoting competition, is open pipeline access. Here users can choose among suppliers. The pipeline function is confined to transportation.

Unbundling of gas trade from transportation would lead to a competitive wellhead market if there were sufficient independent buyers and sellers. Users would build up a portfolio of contracts to match their end-use patterns. Spot markets and futures trading activity would assist market cohesion. A market

12/ This is not to say some market imperfections do not remain: I have already mentioned secondary transportation and LDC transportation access restrictions.

13/ Indeed, much of the variation in European natural gas demand projection relates to power generation.

system would develop a menu of contracts for different types of transportation services.

There must also be the ability to coordinate the bundle of services provided. The complementary relationship between gas purchases and transportation arrangements indicates the interdependent selection of components of the bundle.

Open access would enable gas on gas competition to flourish as long as consumers have easy access to more than one supplier. In Europe, controls, market power and few major suppliers of gas outside of the North Sea preclude this at present. Paradoxically, this may mean pipeline *regulation* to ensure open access is implemented, to monitor or set transportation tariffs, and to avoid discriminating tariffs.[14] And since the use of national pipelines to transport international supplies is a necessity for effective open access, national pipelines may have to be brought under some kind of European regulation umbrella.

The degree of regulatory intervention with respect to tariffs and access regulation depends on the level of competition in the sale of transportation services and the ability of pipelines to exercise market power. The greater the latent power of the pipeline, the greater the role of regulation to ensure competitive access. Vrieling *et al.* (1989) remind us that most US pipeline companies opposed open access. Opposition may be expected in Europe from major transmission lines. But if the European gas market were to be fully integrated and competitive, open access is a *sine qua non*.

If there were third-party access on the European pipelines, how might tariffs be designed? The EC has proposed an "envelope" of long-term costs plus a return on capital. That could embrace a variety of mechanisms.

A competitive market undermines and destroys price discrimination. Netback prices to a common point of supply within a country would tend to equate. Price differences would be less than the costs of transportation between national consumption points. In short, competitive forces would erode all but cost-based differentials or rents.

Interfuel competition will take place in a more volatile price environment than in earlier periods. Although switching between fuels—the substitution effect—is triggered by price differentials, the switching price "zone" is determined by the costs of switching, behavioral habits, institutional resistance and storage costs. The notion of a switching zone implies that substitution does not take place smoothly over an entire price spectrum. Rather it will be triggered over certain distinct price intervals (estimators of constant price elasticity demand models beware). The greatest impact of price volatility on individual fuel demands will be in the power generation market, given many dual-fired facilities.

Natural gas pricing regimes have straddled pricing to the thermal equivalence of other fuels, or beyond to so-called premium values, and pricing at cost (though what constitutes cost is often vague). In the 1970s in North America, gas was often presumed to be a 'noble' fuel, too valuable to be burnt to generate power. And in Europe, supposed looming supply shortages resulted in bans against use of gas for power generation. Competitive prices will clear markets without reference to such artificial yardsticks or constraints. Colloquially this is often referred to as prices being set by "gas on gas" competition.[15]

If the merchant role of pipelines were eliminated, some have suggested that the ability of pipelines to optimize flows and deliveries would be jeopardized. With buyer-seller contracts, the nomination of volumes for delivery would be out of the control of the pipeline.[16] However, North American experience suggests elimination of vertical integration has not led to inefficiencies.

But this experience does indicate the need for open access to allow room for trading activities. A trading function can be greatly assisted

14/ Already, the UK regulator—Ofgas—is looking at pipeline tariffs.

15/ This very term is revealing, an indication of prior price regulation or discrimination.

16/ For example, Teece (1991) has argued that in the absence of vertical integration or a regime of long-term contracts, inefficiencies will be generated by lack of harmonization.

by the development of market "hubs," acting as a clearinghouse for buyers and sellers. The various advantages of "hubs" are well described in Funk (1992, pp. 9-36). "Hubs" are an important feature of competitive gas trade on both a short-term and long-term basis in North America, as discussed earlier. Hub developments would be necessary in Europe,[17] and would be located at convenient points of pipeline intersection. An example here would be the Zeebrugge line (the Interconnector), which is capable of flows in both directions, with Dutch or even FSU gas flowing to the UK, and UK gas flowing to the European mainland. Another example might emerge in Austria, at a potential interconnection among lines from Russia, Norway, southern FSU republics, and even Iran.

B. Alternative Competitive Exchange Systems for Buying and Transporting Gas

A competitive exchange system could take alternative forms. Funk (1992) distinguishes between bargaining procedures, posted offer price systems, and auctions.

With bargaining, buyers and sellers negotiate contracts. Information requirements for participants with options of several supply alternatives and pipeline connections are extensive. But gas purchase deals and transportation need matching. Buying gas spot and transporting it on an interruptible basis is a form of conditional contracting. Switching back and forth between different markets can entail high transaction costs.

Alternatively, pipelines may post prices for all services offered—transparency would be served. This would be analogous to field posting by refiners in the case of crude oil. Regulated tariffs are equivalent to a posted system, at least for transportation charges. Ideally, such a system would have to respond to changing conditions, for instance by capacity release mechanisms and the discounting of posted tariffs (see earlier).

17/ They would be analogous to oil market hubs—for example, Rotterdam product prices in Europe; in North America, West Texas crude at Chicago.

An auction procedure with a relatively homogenous commodity such as natural gas is feasible. Buyers and sellers could bid—with a clearing house function. This mechanism could also apply to pipeline capacity. Separate auction markets could operate for gas at the wellhead as a first step and for transportation and delivery to the burner tip as a second stage. But experiments have shown such a two-stage auction regime could be inefficient (cited by Funk (1992, pp. 8-33)). And auction procedures may not be well suited to long-term agreements.

In North America, as mentioned beforehand, monthly spot markets operate. Matching transmission capacity to the purchase transaction in the fields or at the "city gate" is done by specialized brokers, marketing affiliates of major lines, or by end-user customers and producers themselves. Transaction costs can be high. European spot market prices would become the transparent reference point for the current market value of natural gas. As in the US, a futures market would act as a risk management device.

C. Possible Gains from Competition in European Gas Markets

Few studies have attempted to estimate net benefits that more competitive gas markets might generate in Europe. An exception is Golombek *et al.* (1994). Three schemes were examined. The first was with third-party access (TPA) but no trading activities, while the UK would import gas only from Norway. There would be a redistribution of production to low-cost proximate producers such as the Netherlands, but price discrimination would remain. If trading were allowed (and the UK still only imports Norwegian gas), price discrimination would erode. The third case would envisage a pipeline link from Belgium to the UK. Here there would be a substantial increase in production from new exporters (while Norwegian and UK production would decline). All end-user prices would fall. Consumers would benefit significantly.

Gjelsvik and Olsen (1989) undertook a netback pricing analysis for three countries: the

UK, France, and Germany. Local distribution, national transmission and c.i.f. import prices were deducted from residential, firm industrial and interruptible industrial prices. The analysis showed significant netback margins and price differentials, especially for firm industrial deliveries. In France and the UK price differentials between firm industrial and other users have been large, while in Germany they have been insignificant. Gains from competition via lower prices and increased consumption would be especially noticeable in the German household sector. Gjelsuik and Olsen concluded that the scope for further penetration by natural gas in Europe and the associated welfare gains would be extensive.[18]

A candidate for empirical analysis of gains from competition is the UK. This country is already about halfway toward implementing a competitive market structure, with British Gas mandated to open up at least 60% of its prior monopoly of contract gas supply to competition—especially for industrial and commercial customers. At present there are 60 or so authorized suppliers, of which one half are active pipeline shippers. Provisions for liberalization of gas supply for the residential market are on the blocks (*Oil and Gas Journal*, July 24, 1995). A fledgling spot market is emerging. This will provide an opportunity for gas contract pricing provisions to be related directly to natural gas prices, not the prices of other sources of energy.

D. Power Generation Markets for Natural Gas: A Rosy Outlook?

A common theme among forecasts of European gas consumption is the strength of the market for gas for power generation. Gas-fired combined cycle generation plants are seen as the least-cost option for new generation—as well as conferring environmental benefits.[19] In 1991, the European Parliament had revoked the ban on using gas for power generation, a quaint measure dating from an era when gas supplies were supposed to be running out. Demand uncertainties militate against long-term commitments via TOP or price indexation mechanisms not finely tuned to market conditions. Flexible operation with existing plants, load shifting and peak clipping match the ability to commission smaller increments in capacity with modular gas-fired construction. Risk is reduced.

This rosy outlook for gas-fired generation is not assured. It requires competition. If the price of natural gas were pegged to oil product prices, the position of gas in the power generation sector could be jeopardized *vis à vis* coal. If coal prices were stable, the implication is that premia held by gas prices over coal should also be stable (such premia reflect the cost and environmental advantages of gas combined cycle). There would be a decoupling of natural gas from oil product prices. In a competitive market, if the marginal source of gas demand were power generation, and if this market were governed by coal prices, then natural gas prices would be linked to coal, not oil products. Apparently, this kind of linkage is already underway.

In the long term, the current favorable position of gas—which would be enhanced by CO_2 taxes—could erode with new cleaner technology, integrated gasification combined cycle, or a new generation of nuclear power plants. Elimination of coal subsidies in Europe could hasten the day of more severe competition for natural gas from coal fired generation using imported coal. It is all too easy to forget that with a more open market, dynamic forces intrude. There would be a heavy incentive for those fuels losing market share to innovate.[20]

And in the US, although *new* plant economics favor gas over coal, the use of gas for

18/ The authors mention that Statoil may wish to trade the apparent security of take or pay (TOP) contracts against the additional outlets that direct access to end users may provide. If so, this would augur well for accommodation of direct purchases.

19/ For a useful discussion of the apparent preferred position of natural gas, see Jonchere (1992).

20/ One study in the US predicted a return to coal dominance as the feedstock for new power plants, although this outlook is predicated on strong increase in natural gas prices *vis à vis* coal prices. Natural gas accounted for about 60% of new US generating capacity added in the 1990s (see AGA *Gas Energy Review*, 1994, September).

power generation has not risen. This is because plant economics for *existing* plants favor coal and there has been virtually no replacement of existing plants. Extending the life of old plants has proved to be cheaper than commissioning new plants. In short, increased utilization of coal plants has met much of the increased load; new gas capacity is mainly for peaking (Ellerman, 1995).

IV. Concluding Remarks

It is tempting to assume that promotion of a European competitive gas market simply requires a regime of open access pipeline transportation. Open access may be a necessary condition, but it is certainly not sufficient. Several other elements would have to be put in place to ensure a cohesive competitive market.

The buyer side of the equation is probably the easiest to satisfy. The industrial and power generation sectors would spearhead the search to buy gas from producers. And the residential and commercial sectors would follow, whether represented by the equivalent of LDCs or other customer groups. The privatization process would help in developing an array of arm's-length buyers.

The supply side has a competitive structure in the UK North Sea. But other sources are dominated by large state-owned companies, such as Statoil, Gazprom, and Sonatrach: concentration is high.[21]

If the merchant role of pipelines were reduced or eliminated, as it must be to make third-party access a reality, then other mechanisms must be erected as well. These include provision for the trading activities of middlemen, development of market hubs—such as might be provided by the mainland end of the Zeebrugge Interconnector—capacity release provisions, and the development of spot and futures markets. And there may be a new regulatory role to be performed by a new body under the auspices of the EC. To be effective, it would have to enjoy trans-national power.

Relinquishing the merchant function by pipelines could result in some messy contractual problems. Renegotiation of TOP obligations may make implementation far from smooth.[22]

If all these good things were to come to pass, some implications are clear. Contracts between producers and sellers will become shorter in duration and more flexible. Large-volume buyers will develop a portfolio of contracts of varying types to match their needs. Natural gas price differentials between countries and within countries will erode. More uniform pricing and less scope for price discrimination especially will favor residential customers.

Market clearance will determine how gas prices relate to the price of other sources of energy. If available gas supplies are bountiful, gas will clear against the price of 'blue collar' fuels, such as heavy oils and coal. If supplies tighten, gas will become a 'white collar' fuel, clearing against the price of lighter petroleum products or electricity. Interfuel competition will not be characterized by oil causing gas prices.

Price provisions in contracts will be more flexible and eschew indexation to the price of other energy sources. Arbitration procedures will become more prevalent. And well-defined pricing reference points via hubs and spot markets will emerge as price transparency evolves.

National boundaries, lower pipeline density and an oligopolistic supply sector will preclude a competitive European gas market from becoming a North American twin. But once more competition is allowed to intrude, its pervasive impact and momentum will surprise many. In that light, the influence of a competitive UK market may prove contagious. The Interconnector line might be the source by which the virus of competition infects the rest of Europe.

21/ For the view that concentration at the producing end of the industry would weaken the position of gas buyers in the event of open pipeline access, see Percebois (1994).

22/ Such problems have already emerged in the UK with British Gas contracts.

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Appendix: European and United States Price and Market Share Data

Table E-1: United Kingdom Fuel Prices (Nominal Pounds Sterling/TOE (Ton of Oil Equivalent))

	Industrial				Households			Power Generation		
Year	LFO	HFO	NG	C	LFO	E	NG	HFO	NG	C
1978	76.08	54.24	50.49	36.96	97.84	318.84	83.53	51.79	39.41	38.86
1979	102.80	67.62	57.76	44.28	126.59	346.51	86.75	59.25	47.40	44.79
1980	147.80	93.02	77.47	55.96	171.53	446.98	105.06	89.30	57.27	56.32
1981	169.00	112.40	92.70	63.10	203.50	537.80	129.00	112.40	121.90	66.20
1982	185.70	119.10	101.30	76.10	233.60	589.90	157.50	114.00	110.00	71.10
1983	191.10	129.30	106.00	78.80	240.60	583.70	168.60	125.70	111.20	75.20
1984	198.60	156.10	114.90	79.00	237.40	604.00	174.10	157.50	111.50	75.70
1985	216.20	157.10	126.30	81.00	250.70	607.00	180.10	173.50	131.70	80.90
1986	140.30	82.50	112.70	78.90	159.00	618.60	182.30	81.70	118.40	81.80
1987	124.90	91.00	104.30	75.50	152.90	604.70	180.20	76.10	95.00	77.40
1988	106.00	66.30	102.30	68.50	126.40	632.60	187.20	55.50	78.80	83.40
1989	120.40	71.00	97.10	69.50	135.20	676.70	198.10	63.60	85.90	81.00
1990	142.80	77.20	99.10	71.00	170.10	775.60	205.90	55.40		77.40
1991	145.40	70.80	102.10	69.70	158.60	846.50	211.40			76.90
1992	129.90	66.00	99.80	69.10	145.10	875.60	218.20			81.10
1993	139.30	66.90	95.50	64.60	155.90	876.70	209.10		90.80	75.10
1994		77.20			154.10					

Table E-2: France Fuel Prices (Nominal Francs/TOE)

	Industrial				Households			Power Generation		
Year	LFO	HFO	NG	C	LFO	E	NG	HFO	NG	C
1978		430.64	493.67			4,227.91	1,448.89			
1979		531.28	542.78			4,644.19	1,514.44			
1980		790.85	827.02			5,603.49	1,944.44			350.04
1981	1,992.00	1,113.30	1,125.60	599.00	2,361.10	6,196.50	2,445.60			515.30
1982	2,428.10	1,283.60	1,368.20	730.50	2,793.10	7,526.70	2,975.90			579.30
1983	2,958.50	1,429.20	1,494.80	741.60	3,063.40	7,993.00	3,250.00			572.40
1984	2,899.60	1,774.40	1,622.70	788.30	3,223.40	8,709.30	3,452.90			592.90
1985	3,312.10	1,710.80	1,788.10	858.40	3,542.60	9,070.90	3,730.30			576.30
1986	2,439.90	941.50	1,209.60	789.90	2,371.80	9,001.20	3,503.50			491.60
1987	1,944.80	913.80	996.10	766.20	2,282.80	8,898.80	2,914.40			419.10
1988	1,803.40	637.40	883.70	717.50	2,146.40	9,046.50	2,860.80			417.20
1989	2,074.50	782.80	918.60	706.20	2,351.20	9,067.40	2,879.00			486.70
1990	2,215.90	761.70	938.90	733.80	2,590.60	9,509.30	2,871.00			443.70
1991	1,968.40	673.00	948.30	741.60	2,703.20	9,301.20	2,895.40			431.10
1992	1,697.30	652.80	898.70	748.10	2,412.60	9,487.20	2,941.00			401.40
1993	1,743.60	609.50	899.70	754.50	2,464.90	9,638.40	2,872.10			386.90
1994	1,671.20	818.70	874.60	754.50	2,403.30		2,835.30			

Table E-3: Germany Fuel Prices (Nominal Deutschmarks/TOE)

	Industrial				Households			Power Generation		
Year	LFO	HFO	NG	C	LFO	E	NG	HFO	NG	C
1978			238.89				1,994.19	554.77		174.18
1979			246.17				2,032.56	562.57		187.88
1980			316.99				2,123.26	677.38		255.89
1981	726.00	493.70	409.80		820.40	2,396.50	815.30	502.80	359.60	348.20
1982	803.20	469.00	558.20		907.50	2,610.50	959.30	473.50	427.10	369.30
1983	728.10	466.30	534.40		826.30	2,684.90	948.40	471.30	412.40	364.90
1984	771.50	556.70	571.30		879.50	2,762.80	952.40	559.10	462.30	367.20
1985	802.80	545.50	605.20		915.20	2,800.00	981.20	543.10	482.70	383.50
1986	433.20	240.60	474.60		493.80	2,887.20	901.60	228.50	391.40	363.00
1987	375.10	232.70	305.70		427.60	2,927.90	640.70	236.40	297.90	346.30
1988	324.80	186.70	276.10		370.30	3,026.70	621.60	179.20	244.40	346.20
1989	441.20	235.20	300.70		502.90	3,077.90	651.10	244.20	268.80	359.20
1990	486.70	236.00	336.70		554.80	3,077.90	712.00	241.00	283.80	362.40
1991	518.30	233.00	370.80		590.90	3,071.90	782.70	247.60	305.40	358.00
1992	454.60	213.30	348.00		518.20	3,123.60	789.90	224.10	293.90	372.70
1993	457.90	199.90	344.00		526.70	3,248.80	781.20	214.90	279.70	367.20
1994	424.30	201.60			488.00			209.30		367.60

Key: LFO–light fuel oil; HFO–heavy fuel oil; NG–natural gas; C–coal; E–electricity
Source: IEA, *Energy Prices and Taxes,* various years

Table E-4: Finland Fuel Prices (Nominal Finnish Marks/TOE)

	Industrial				Households			Power Generation		
Year	LFO	HFO	NG	C	LFO	E	NG	HFO	NG	C
1978	672.88	418.75	460.43	293.60	672.88	2,755.81	460.43	418.75		293.60
1979	846.56	502.08	464.57	312.65	846.56	2,790.70	464.57	502.08		312.65
1980	1,322.75	788.54	840.22	399.94	1,322.75	3,000.00	840.22	788.54		399.94
1981	1,656.30	1,003.10	1,130.40	596.80	1,656.30	3,430.20	1,130.40	1,003.10		596.80
1982	1,696.60	1,040.60	1,116.60	581.00	1,696.60	3,779.10	1,116.60	1,040.60		581.00
1983	1,817.30	1,085.40	1,198.00	426.70	1,817.30	3,686.00	1,198.00	1,085.40		426.70
1984	1,872.60	1,172.90	1,164.90	409.40	1,872.60	3,651.20	1,164.90	1,172.90		409.40
1985	1,889.80	1,337.50	1,147.00	490.60	1,889.80	3,767.40	1,147.00	1,337.50		490.60
1986	1,103.20	670.70	769.10	418.70	1,226.10	3,790.70	828.60	670.70		418.70
1987	968.60	591.00	577.00	325.40	1,153.10	4,232.60	686.90	591.00		325.40
1988	869.60	575.70	540.20	324.00	1,035.20	4,177.90	643.10	575.70		324.00
1989	966.10	666.40	566.60	366.90	1,227.90	4,255.80	678.60	666.40		366.90
1990	1,267.30	714.60	623.30	382.10	1,526.90	4,572.70	751.00	714.60		382.10
1991	1,253.00	662.20	630.00	384.10	1,521.20	4,755.80	764.80	662.20		384.10
1992	1,280.40	674.00	645.60	410.00	1,561.40	4,904.10	774.60	674.00		410.00
1993	1,551.50	835.30	669.90	423.10	1,892.10	5,354.70	817.60	833.20		423.10
1994	1,405.30	912.90	697.40	471.90	1,713.80	5,343.00	850.50	912.90		471.90

Key: LFO–light fuel oil; HFO–heavy fuel oil; NG–natural gas; C–coal; E–electricity
Source: IEA, *Energy Prices and Taxes,* various years

Table E-5: United Kingdom Fuel Shares (%)

	Industrial					Households					Power Generation					
Year	C	OS	PP	NG	E	C	OS	PP	NG	E	C	OS	PP	NG	N	H
1978	17.3	0.0	43.8	24.5	14.4	24.5	0.0	9.3	45.9	20.2	65.7	0.0	18.5	1.5	13.0	1.4
1979	19.2	0.0	40.6	25.4	14.9	20.6	0.0	10.0	49.4	20.0	67.7	0.0	16.7	1.0	12.8	1.8
1980	14.9	0.1	38.0	30.1	16.7	18.8	0.0	7.5	53.2	20.6	73.2	0.0	11.7	0.7	13.0	1.4
1981	17.2	0.0	36.7	29.4	16.6	17.7	0.0	6.7	55.3	20.2	74.8	0.0	9.4	0.5	13.7	1.6
1982	17.2	0.1	35.6	30.7	16.3	17.8	0.0	6.4	55.8	20.1	71.9	0.0	9.7	0.5	16.2	1.7
1983	18.3	0.0	33.6	31.3	16.7	16.7	0.0	6.1	57.0	20.2	70.6	0.0	9.0	0.6	18.1	1.7
1984	17.8	0.0	32.3	32.1	17.7	13.6	0.0	6.5	58.9	21.0	45.7	0.0	32.7	1.0	19.2	1.5
1985	20.1	0.0	30.3	31.8	17.7	16.3	0.0	6.1	57.7	19.9	60.5	0.0	16.4	1.0	20.7	1.4
1986	20.0	0.0	33.1	28.6	18.2	15.4	0.0	6.2	58.5	19.9	67.7	0.0	10.4	0.6	19.7	1.6
1987	20.3	0.0	30.7	30.7	18.3	13.6	0.0	5.9	60.2	20.3	70.9	0.0	8.7	0.6	18.4	1.4
1988	21.2	0.0	32.8	27.5	18.5	13.1	0.0	6.0	60.3	20.6	67.3	0.0	9.7	0.7	20.7	1.6
1989	20.3	0.0	31.0	28.2	20.4	11.8	0.0	6.1	60.7	21.4	66.4	0.4	7.5	1.2	23.0	1.5
1990	19.7	0.0	29.1	30.0	21.2	9.8	0.0	6.3	62.1	21.7	67.5	0.5	8.6	1.1	20.7	1.6
1991	18.8	0.3	33.1	27.5	20.3	9.1	0.4	6.5	63.3	20.7	65.3	0.3	9.4	1.3	22.0	1.7
1992	18.9	0.2	33.3	26.4	21.2	8.1	0.4	6.8	63.5	21.3	62.2	0.4	8.5	2.7	24.1	2.0

Table E-6: France Fuel Shares (%)

	Industrial					Households					Power Generation					
Year	C	OS	PP	NG	E	C	OS	PP	NG	E	C	OS	PP	NG	N	H
1978	15.0	0.0	52.4	17.2	15.4	9.2	0.0	64.8	12.6	13.4	26.7	0.0	26.4	2.8	13.4	30.7
1979	17.6	0.0	50.5	16.9	15.0	9.5	0.0	68.7	11.2	10.5	27.9	0.0	24.1	3.4	16.6	28.1
1980	17.3	1.3	49.0	17.4	15.0	17.5	11.7	11.8	29.9	29.1	27.2	0.3	18.9	2.7	23.8	26.9
1981	19.2	1.5	40.3	21.8	17.2	15.4	12.7	11.2	30.7	30.0	21.3	0.3	11.8	2.1	38.3	25.9
1982	19.8	1.3	40.3	21.0	17.5	14.2	13.9	10.7	30.1	31.1	23.7	0.4	9.4	1.9	39.3	25.0
1983	17.7	1.3	41.7	21.7	17.6	13.7	13.9	10.0	30.0	32.5	20.3	0.2	5.3	1.7	49.0	23.2
1984	19.9	1.3	36.7	23.8	18.2	12.5	13.5	9.5	31.2	33.3	16.2	0.3	2.6	1.2	59.4	20.1
1985	20.9	1.3	35.9	23.5	18.4	12.4	13.4	9.2	30.8	34.2	13.1	0.2	2.1	0.9	65.6	17.9
1986	20.5	1.4	34.1	24.0	20.0	11.3	13.4	8.7	32.0	34.7	9.5	0.2	1.5	0.8	70.6	17.2
1987	19.0	1.4	35.5	24.0	20.2	10.2	13.3	8.8	31.8	35.9	8.2	0.2	1.6	0.6	70.7	18.5
1988	19.6	1.3	34.3	23.7	21.0	8.9	14.3	8.5	31.4	36.8	7.4	0.2	1.5	0.6	70.9	19.3
1989	19.8	1.4	32.4	24.5	22.0	8.4	14.7	8.1	31.1	37.6	9.0	0.2	3.0	0.7	75.4	11.6
1990	19.4	1.4	30.5	26.0	22.6	7.7	14.7	8.1	30.7	38.8	8.5	0.2	2.1	0.7	75.5	12.8
1991	17.3	1.3	34.7	25.6	21.2	7.3	13.1	7.9	33.3	38.3	9.6	0.2	3.2	0.6	73.6	12.6
1992	16.5	1.2	36.4	24.4	21.6	5.8	14.0	7.8	33.6	38.8	8.2	0.2	2.1	0.7	73.9	14.8

Key: C–coal OS–other solids; PP–petroleum products; NG–natural gas; E–electricity; N–nuclear; H–hydro
Source: IEA, *Energy Balances,* various years

Table E-7: Germany Fuel Shares (%)

	Industrial					Households					Power Generation					
Year	C	OS	PP	NG	E	C	OS	PP	NG	E	C	OS	PP	NG	N	H
1978	21.1	0.0	41.8	19.9	17.3	9.2	0.0	57.8	15.5	17.5	57.0	0.0	9.3	18.3	10.2	5.2
1979	21.0	0.0	41.1	20.1	17.7	10.7	0.0	55.6	21.1	12.5	57.5	0.0	7.5	18.7	11.4	5.0
1980	24.3	0.0	37.1	20.2	18.4	10.2	0.8	67.8	1.2	19.9	58.3	1.5	7.0	16.6	11.9	4.7
1981	26.5	0.1	33.3	21.0	19.2	9.8	1.1	66.0	1.2	21.9	60.8	1.4	5.5	12.8	14.6	5.0
1982	26.2	0.1	32.8	20.6	20.3	9.5	1.0	65.4	1.0	23.1	61.4	1.4	4.7	10.2	17.4	4.9
1983	25.7	0.1	33.2	20.8	20.2	8.3	1.3	65.1	0.9	24.3	63.3	1.1	3.4	9.9	17.7	4.6
1984	27.2	0.1	30.6	21.4	20.8	5.9	1.5	50.0	25.3	17.3	60.2	1.2	2.3	8.5	23.5	4.3
1985	27.5	0.1	29.6	21.5	21.3	6.0	1.4	50.4	25.4	16.8	55.7	1.1	2.3	6.1	31.0	3.8
1986	24.6	0.1	30.8	22.0	22.5	5.3	1.4	51.6	25.3	16.5	56.1	1.1	3.1	6.2	29.4	4.1
1987	23.8	0.2	30.1	23.0	22.9	4.9	1.4	47.4	28.7	17.5	53.4	0.9	3.0	6.9	31.4	4.5
1988	24.3	0.2	30.2	22.5	22.9	4.2	1.5	47.2	28.4	18.6	51.4	1.0	2.6	6.8	33.8	4.3
1989	24.3	0.1	28.9	23.4	23.2	3.8	1.7	41.4	32.4	20.8	50.9	1.1	2.2	7.9	34.1	3.8
1990	23.1	0.1	29.2	24.1	23.5	3.5	1.7	42.8	31.7	20.3	52.2	1.1	2.2	8.0	32.9	3.6
1991	23.6	0.2	29.2	22.7	22.3	10.6	1.3	36.8	28.2	17.5	59.3	0.9	2.8	6.8	27.5	2.7
1992	21.2	0.1	30.5	23.5	22.8	6.5	1.3	38.3	29.8	18.2	57.3	1.0	2.5	6.2	29.8	3.3

Table E-8: Finland Fuel Shares (%)

	Industrial						Households						Power Generation					
Year	C	OS	PP	NG	E	DH	C	OS	PP	NG	E	DH	C	OS	PP	NG	N	H
1978		27.8	42.6	6.5	22.9		30.2 *		59.4	0.6	9.8		42.8	0.0	14.0	4.9	9.3	29.1
1979		31.8	40.8	5.1	22.3		28.7 *		59.2	0.2	12.1		38.6	0.0	11.6	4.5	17.3	27.9
1980	8.6	24.9	37.8	4.7	22.6	1.4	1.2	14.2	57.8	0.8	13.2	13.1	30.9	11.7	10.8	4.2	17.2	25.1
1981	8.9	26.4	36.0	4.9	22.4	1.3	1.1	13.1	54.4	0.4	15.6	15.6	10.1	11.6	6.6	2.5	35.8	33.4
1982	10.0	27.9	34.4	4.6	21.8	1.3	1.4	6.7	54.0	0.2	18.5	19.2	10.2	10.7	4.3	2.3	40.7	31.8
1983	10.6	29.1	30.8	4.8	23.4	1.5	0.7	12.1	48.7	0.5	18.8	19.3	10.4	11.1	2.5	1.8	42.0	32.2
1984	10.4	29.3	29.2	5.1	24.6	1.5	1.0	12.6	43.6	0.7	21.4	21.2	11.5	13.2	2.6	1.8	41.7	29.2
1985	12.8	27.7	24.1	5.3	27.9	2.1	0.6	12.7	41.1	0.6	22.2	22.9	18.5	12.8	2.7	2.9	38.3	24.8
1986	10.5	27.3	27.4	6.4	26.6	1.9	0.4	14.1	40.6	0.2	22.7	21.9	16.6	13.3	2.5	3.7	38.7	25.1
1987	12.1	28.3	22.8	6.9	27.9	2.1	0.4	13.6	41.6		22.5	21.9	18.2	12.4	2.7	4.0	36.8	25.8
1988	11.9	29.3	20.9	7.7	28.3	1.9	0.2	8.0	45.7	0.4	23.5	22.4	18.7	12.3	3.0	4.9	36.3	24.8
1989	13.3	28.1	19.7	9.7	27.4	1.7	0.2	12.6	41.6	0.6	24.0	21.1	17.0	13.9	2.1	7.3	35.5	24.2
1990	13.1	27.5	17.7	12.4	27.6	1.7	0.2	12.9	41.3	0.6	24.1	20.8	18.9	14.6	2.4	8.8	35.2	20.0
1991	10.5	25.1	20.5	13.5	28.5	1.9	0.2	12.9	40.1	0.7	25.1	21.0	17.6	15.6	1.8	8.5	33.6	22.8
1992	9.8	28.5	16.9	14.1	28.8	1.9	0.2	12.7	40.1	0.7	25.4	20.9	14.1	15.0	2.0	8.9	33.6	26.4

* Includes OS and DH for these years
Key: C–coal; OS–other solids; PP–petroleum products; NG–natural gas; E–electricity; DH–district heating; N–nuclear; H–hydro
Source: IEA, *Energy Balances,* various years

Table US-1: New York State Fuel Prices (Nominal Dollars/Million BTU)

	Industrial				Residential			Commercial			Power Generation			
Year	NG	R	E	C	NG	O	E	NG	O	E	NG	C	N	R
1970	0.68	0.49	3.51	0.53	1.37	1.48	8.83	1.17	1.14	7.80	0.38	0.47	0.20	0.42
1971	0.76	0.65	3.89	0.64	1.47	1.55	9.49	1.24	1.21	8.92	0.43	0.53	0.23	0.54
1972	0.84	0.62	4.16	0.66	1.58	1.56	10.05	1.28	1.21	9.52	0.46	0.52	0.26	0.62
1973	0.88	0.77	4.43	0.75	1.69	1.81	10.98	1.33	1.42	10.41	0.50	0.50	0.25	0.80
1974	1.09	1.85	6.74	1.47	1.96	2.73	14.98	1.55	2.34	15.22	0.69	1.06	0.33	2.03
1975	1.47	2.01	7.97	1.82	2.50	2.89	16.44	1.97	2.48	16.57	0.88	1.18	0.31	1.94
1976	1.55	2.00	7.99	1.86	2.83	3.06	16.97	2.32	2.64	17.38	1.07	1.13	0.35	1.91
1977	1.90	2.26	8.97	1.83	3.25	3.46	18.40	2.82	3.06	18.68	1.41	1.17	0.36	2.19
1978	2.24	2.28	9.25	1.95	3.63	3.70	18.97	3.02	3.22	18.24	1.49	1.29	0.39	2.03
1979	2.70	2.81	10.42	1.99	4.07	5.22	20.93	3.45	4.65	19.67	2.29	1.36	0.47	2.96
1980	3.43	3.78	12.11	2.08	4.85	7.22	23.08	4.17	6.48	23.21	2.67	1.47	0.56	4.25
1981	3.89	4.83	15.55	2.26	5.41	9.00	28.98	4.65	8.20	29.35	3.49	1.71	0.56	5.10
1982	4.87	4.65	16.43	2.34	6.38	8.87	30.76	5.37	7.95	31.03	3.91	1.83	0.60	4.69
1983	5.54	4.40	15.66	2.02	7.67	8.58	32.08	6.31	7.26	33.00	3.98	1.79	0.56	4.54
1984	5.22	5.03	16.41	1.92	7.45	8.77	31.17	6.10	7.46	31.04	3.99	1.80	0.64	4.76
1985	5.13	4.64	15.34	1.90	7.54	8.58	31.84	5.95	7.03	30.86	3.48	1.72	0.67	4.26
1986	4.78	2.92	14.43	1.75	7.26	7.04	30.86	5.61	5.34	29.62	2.24	1.65	0.61	2.47
1987	4.16	3.22	14.74	1.68	6.68	6.63	30.81	5.02	5.24	27.96	2.44	1.54	0.63	3.06
1988	4.56	2.67	14.47	1.66	6.32	6.71	30.67	5.24	5.12	27.13	2.24	1.58	0.57	2.49
1989	4.69	3.12	15.52	1.71	7.01	7.51	32.03	5.46	5.53	27.99	2.35	1.57	0.65	2.95
1990	4.72	3.75	16.94	1.74	7.19	8.92	33.54	5.43	6.70	29.44	2.38	1.61	0.65	3.60
1991	4.60	2.83	18.07	1.73	7.16	9.06	35.09	5.33	6.42	30.31	2.23	1.59	0.55	2.72
1992	4.79	2.89	19.05	1.74	7.37	8.38	36.43	5.59	5.76	31.48	2.41	1.49	0.45	2.63

Table US-2: California Fuel Prices (Nominal Dollars/Million BTU)

	Industrial				Residential			Commercial			Power Generation			
Year	NG	R	E	C	NG	O	E	NG	O	E	NG	C	N	R
1970	0.38	0.35	2.90	0.43	0.93	2.49	6.53	0.69	1.12	5.02	0.33		0.19	0.40
1971	0.42	0.57	3.03	0.47	0.98	2.44	6.78	0.72	1.18	5.31	0.35		0.19	0.63
1972	0.45	0.57	3.30	0.52	1.03	2.56	7.22	0.77	1.18	5.63	0.38		0.19	0.79
1973	0.51	0.76	3.75	0.61	1.11	3.27	7.72	0.81	1.41	6.14	0.42		0.18	0.94
1974	0.65	1.65	5.74	1.29	1.31	4.14	9.89	0.94	2.37	8.04	0.59		0.12	2.01
1975	1.05	1.66	6.70	1.32	1.49	4.17	10.68	1.22	2.60	8.73	1.05		0.21	2.50
1976	1.39	1.59	7.62	1.43	1.68	4.27	11.19	1.51	2.90	9.61	1.56		0.28	2.34
1977	1.86	1.87	9.46	1.47	1.80	4.83	12.41	1.97	3.00	12.04	2.10		0.28	2.37
1978	2.04	1.79	10.75	1.59	1.89	4.76	13.13	2.13	3.04	13.10	2.18		0.29	2.58
1979	2.61	2.26	10.96	1.69	2.36	6.20	13.10	2.61	4.38	13.07	2.45		0.37	3.14
1980	3.64	3.16	16.04	1.91	3.37	8.14	17.18	3.82	6.60	17.99	3.53		0.49	5.03
1981	3.88	4.02	18.11	2.16	3.58	7.73	19.09	4.19	7.54	19.30	3.99		0.85	6.62
1982	4.66	4.25	21.24	2.19	4.24	9.98	22.47	5.08	7.49	21.78	5.02		0.77	6.77
1983	5.28	4.27	19.83	2.37	5.20	10.93	20.88	6.08	7.44	21.41	5.08		1.07	6.06
1984	5.01	4.49	19.59	2.39	5.62	9.67	20.73	6.70	7.16	22.03	5.09		1.11	5.97
1985	4.54	3.93	22.00	2.28	5.51	8.53	22.80	6.39	5.40	23.61	4.47		0.96	5.31
1986	3.46	2.16	21.63	2.26	4.95	10.82	23.26	5.65	5.56	24.19	2.81		0.97	3.16
1987	3.39	2.60	20.38	2.09	5.13	11.84	23.55	5.28	4.81	23.47	2.50		0.99	2.82
1988	3.65	2.09	20.15	1.96	5.48	11.04	25.02	4.55	4.94	24.15	2.83		0.90	2.66
1989	3.62	2.30	20.89	1.92	5.40	11.46	27.69	4.71	6.22	25.33	2.92		0.85	3.08
1990	3.79	3.00	21.35	2.00	5.60	12.00	29.26	4.96	5.72	26.31	3.03		0.72	4.36
1991	3.86	2.24	22.22	1.97	6.11	12.39	31.61	5.36	5.42	28.12	2.87		0.67	3.06
1992	3.57	2.26	22.24	1.83	5.81	12.99	32.46	5.01	6.07	29.05	2.72		0.55	2.18

Key: NG–natural gas; R–residual fuel oil; E–electricity; C–coal; O–oil; N–nuclear
Source: US DOE/EIA, *State Energy Price and Expenditure Report*, 1993

Table US-3: Illinois Fuel Prices (Nominal Dollars/Million BTU)

	Industrial				Residential			Commercial			Power Generation			
Year	NG	R	E	C	NG	O	E	NG	O	E	NG	C	N	R
1970	0.49	0.59	3.56	0.44	1.02	1.48	7.97	0.73	1.04	6.61	0.35	0.30	0.15	0.60
1971	0.55	0.71	3.76	0.46	1.05	1.51	8.30	0.76	1.10	6.96	0.38	0.34	0.16	0.61
1972	0.62	0.71	4.05	0.54	1.11	1.57	8.77	0.82	1.10	7.40	0.42	0.39	0.15	0.65
1973	0.67	0.90	4.22	0.57	1.19	2.21	9.20	0.87	1.44	7.60	0.60	0.42	0.16	0.67
1974	0.79	2.12	5.21	1.03	1.32	2.91	10.43	0.99	2.38	8.95	0.76	0.55	0.17	1.24
1975	1.19	2.14	6.43	1.33	1.57	2.95	11.41	1.28	2.39	10.38	1.13	0.75	0.18	1.35
1976	1.43	2.08	7.04	1.36	1.85	3.22	12.18	1.60	2.60	11.15	1.37	0.85	0.19	2.04
1977	1.80	2.28	7.72	1.48	2.15	3.69	12.88	1.93	2.99	11.79	1.79	1.02	0.21	2.45
1978	2.09	2.31	8.99	1.71	2.46	3.68	14.38	2.23	3.09	13.21	2.73	1.25	0.25	2.53
1979	2.56	2.94	9.68	1.70	2.93	5.37	15.50	2.74	4.65	14.28	2.69	1.45	0.30	3.82
1980	3.10	3.78	11.82	1.79	3.53	7.02	17.78	3.27	6.49	16.70	3.19	1.62	0.33	5.60
1981	3.54	4.58	13.49	1.94	3.97	7.92	20.66	3.67	7.87	19.37	4.13	1.86	0.42	7.35
1982	4.17	4.35	15.34	2.05	4.63	8.06	23.06	4.34	7.53	21.71	4.58	1.98	0.51	7.06
1983	4.64	4.46	17.20	1.94	5.25	8.03	26.92	4.77	6.67	23.30	5.29	2.04	0.56	6.18
1984	4.43	4.85	15.48	1.90	5.16	7.76	25.67	4.67	6.44	22.51	4.87	1.99	0.56	6.19
1985	4.57	4.14	15.35	1.88	5.34	7.76	26.42	4.84	6.11	22.36	5.19	2.18	0.64	6.03
1986	4.06	2.38	16.46	1.78	4.96	6.00	27.74	4.47	4.03	23.72	4.62	2.12	0.64	5.24
1987	3.77	2.93	16.54	1.64	4.74	6.54	29.82	4.33	4.22	22.95	3.66	2.00	0.64	3.56
1988	3.36	2.39	15.14	1.63	4.52	6.35	28.54	4.12	4.00	21.38	3.27	1.91	0.66	2.95
1989	3.65	2.43	15.75	1.61	4.81	7.32	29.21	4.45	4.72	22.24	3.26	1.81	0.60	3.36
1990	4.01	2.29	15.83	1.58	4.95	7.74	29.07	4.54	5.67	22.18	2.67	1.75	0.57	3.63
1991	3.70	2.63	16.09	1.63	4.86	7.10	28.92	4.47	4.91	22.68	2.10	1.71	0.49	2.73
1992	3.68	2.80	16.04	1.59	5.00	7.35	30.17	4.57	4.70	23.07	2.20	1.74	0.52	2.81

Key: NG–natural gas; R–residual fuel oil; E–electricity; C–coal; O–oil; N–nuclear
Source: US DOE/EIA, *StateEnergy Price and Expenditure Report,* 1993

Table US-4a: New York State Fuel Consumption (Trillions of BTUs)

	Industrial				Residential			Commercial			Power Generation				
Year	NG	R	E	C	NG	O	E	NG	O	E	NG	C	O	N	H
1970	118.0	318.5	92.6	308.4	353.8	392.4	87.0	142.4	402.0	113.4	108.4	274.4	375.3	46.9	270.0
1971	119.5	304.0	92.1	222.8	359.5	389.4	91.1	148.5	378.5	118.5	100.6	198.0	476.2	70.7	272.6
1972	105.7	304.3	94.0	195.6	370.6	404.9	94.8	150.3	374.7	125.0	77.2	148.3	563.2	69.8	302.4
1973	128.3	307.6	102.0	214.6	352.9	402.2	100.7	147.0	377.7	132.5	71.6	143.4	577.7	78.8	326.7
1974	111.4	274.6	101.9	207.1	348.8	370.4	96.2	139.4	336.0	124.7	39.3	156.4	544.0	103.5	331.4
1975	106.2	247.9	93.0	155.5	332.2	358.7	98.0	130.2	300.0	129.0	14.0	147.3	561.0	144.4	309.8
1976	105.6	287.4	97.8	208.9	344.7	399.6	100.5	145.5	345.2	130.4	5.4	147.4	547.1	173.0	321.9
1977	99.5	300.0	105.5	167.6	329.1	394.9	101.6	132.3	353.3	131.5	4.2	160.8	556.2	221.7	297.6
1978	92.2	283.2	109.4	136.6	334.9	390.9	102.2	144.7	332.8	135.3	1.3	150.8	557.8	237.4	318.2
1979	89.2	280.4	112.2	154.0	317.2	279.5	103.1	145.4	237.2	135.8	78.2	153.7	434.2	201.3	395.2
1980	116.4	159.5	109.6	146.5	341.5	238.5	104.3	165.5	252.3	138.4	128.9	158.8	406.1	210.3	347.0
1981	124.2	95.2	110.0	138.7	342.7	222.4	104.8	170.2	168.5	145.5	134.7	158.4	396.7	192.4	415.7
1982	113.1	109.1	104.0	108.3	350.3	203.9	104.5	168.3	205.5	146.1	157.2	165.5	352.9	159.9	422.9
1983	100.1	63.2	107.2	90.9	330.3	190.5	108.5	166.0	162.0	150.8	140.0	167.6	364.1	178.6	488.5
1984	110.6	71.2	98.2	103.6	345.8	192.5	112.0	174.7	188.0	163.9	175.2	184.1	308.7	229.7	495.9
1985	103.6	73.5	97.8	94.8	328.8	210.4	111.8	170.0	190.8	167.2	178.7	196.2	276.5	260.5	462.2
1986	90.0	63.1	95.9	81.7	345.9	222.9	115.2	172.1	234.6	173.1	138.4	160.2	335.4	238.5	469.5
1987	100.0	62.2	98.0	84.7	344.4	243.2	120.4	172.2	216.9	179.9	178.5	200.2	329.6	247.1	448.1
1988	94.3	60.3	102.9	91.5	367.5	249.3	127.8	193.4	209.3	190.1	153.1	233.7	407.7	259.7	372.6
1989	100.3	61.3	107.3	94.4	375.4	232.8	129.2	202.1	202.5	192.8	187.1	260.5	427.5	245.0	293.6
1990	105.1	53.6	108.9	82.6	347.8	179.3	131.6	200.6	196.9	192.4	230.6	256.7	344.2	252.3	270.8
1991	123.3	38.6	106.2	82.2	348.1	175.9	133.7	205.0	190.0	193.8	218.2	255.2	284.5	305.5	294.5
1992	152.7	42.7	105.9	71.3	389.6	188.2	132.1	223.5	190.3	192.7	215.0	258.6	183.4	257.9	303.7

Table US-4b: New York State Fuel Shares (%)

	Industrial				Residential			Commercial			Power Generation				
Year	NG	R	E	C	NG	O	E	NG	O	E	NG	C	O	N	H
1970	14.1	38.0	11.1	36.8	42.5	47.1	10.4	21.8	60.8	17.4	10.1	25.5	34.9	4.4	25.1
1971	16.2	41.2	12.5	30.2	42.8	46.4	10.8	23.2	58.3	18.5	9.0	17.7	42.6	6.3	24.4
1972	15.1	43.5	13.4	28.0	42.6	46.5	10.9	23.3	57.3	19.4	6.7	12.8	48.5	6.0	26.0
1973	17.1	40.9	13.5	28.5	41.2	47.0	11.8	22.6	57.1	20.3	6.0	12.0	48.2	6.6	27.3
1974	16.0	39.5	14.7	29.8	42.8	45.4	11.8	23.5	55.6	21.0	3.3	13.3	46.3	8.8	28.2
1975	17.6	41.1	15.4	25.8	42.1	45.5	12.4	23.5	53.1	23.3	1.2	12.5	47.7	12.3	26.3
1976	15.1	41.1	14.0	29.9	40.8	47.3	11.9	23.7	55.2	21.2	0.5	12.3	45.8	14.5	26.9
1977	14.8	44.6	15.7	24.9	39.9	47.8	12.3	21.6	56.8	21.5	0.3	13.0	44.8	17.9	24.0
1978	14.8	45.6	17.6	22.0	40.4	47.2	12.3	23.8	53.9	22.3	0.1	11.9	44.1	18.8	25.1
1979	14.0	44.1	17.7	24.2	45.3	39.9	14.7	28.4	45.1	26.5	6.2	12.2	34.4	15.9	31.3
1980	21.9	30.0	20.6	27.5	49.9	34.9	15.2	30.0	44.8	25.1	10.3	12.7	32.5	16.8	27.7
1981	26.5	20.3	23.5	29.6	51.2	33.2	15.6	35.6	34.0	30.4	10.4	12.2	30.6	14.8	32.0
1982	26.0	25.1	23.9	24.9	53.2	31.0	15.9	32.7	38.9	28.4	12.5	13.2	28.0	12.7	33.6
1983	27.7	17.5	29.7	25.1	52.5	30.3	17.2	35.0	33.1	31.8	10.5	12.5	27.2	13.3	36.5
1984	28.8	18.6	25.6	27.0	53.2	29.6	17.2	33.5	35.0	31.5	12.6	13.2	22.2	16.5	35.6
1985	28.0	19.9	26.4	25.6	50.5	32.3	17.2	32.8	34.9	32.3	13.0	14.3	20.1	19.0	33.6
1986	27.2	19.1	29.0	24.7	50.6	32.6	16.8	30.2	39.4	30.4	10.3	11.9	25.0	17.8	35.0
1987	29.0	18.0	28.4	24.5	48.6	34.3	17.0	30.6	37.3	32.0	12.7	14.3	23.5	17.6	31.9
1988	27.0	17.3	29.5	26.2	49.3	33.5	17.2	33.0	34.7	32.4	10.7	16.4	28.6	18.2	26.1
1989	27.6	16.9	29.5	26.0	50.9	31.6	17.5	34.2	33.1	32.7	13.2	18.4	30.2	17.3	20.8
1990	30.0	15.3	31.1	23.6	52.8	27.2	20.0	34.4	32.7	33.0	17.0	19.0	25.4	18.6	20.0
1991	35.2	11.0	30.3	23.5	52.9	26.7	20.3	35.0	31.8	33.1	16.1	18.8	21.0	22.5	21.7
1992	41.0	11.5	28.4	19.1	54.9	26.5	18.6	37.1	31.0	32.0	17.6	21.2	15.0	21.2	24.9

Key: NG–natural gas; R–residual fuel oil; E–electricity; C–coal; O–oil; N–nuclear; H–hydro
Source: US DOE/EIA, *State Energy Data Report*, 1992, Consumption Estimates

Table US-5a: California Fuel Consumption (Trillions of BTUs)

	Industrial				Residential			Commercial			Power Generation					
Year	NG	R	E	C	NG	O	E	NG	O	E	NG	C	O	N	H	G
1970	749.1	76.2	143.9	59.3	582.4	23.4	122.1	221.3	72.2	138.7	670.6	0.0	136.4	34.4	399.5	11.3
1971	734.7	63.7	150.1	50.9	665.1	24.8	133.3	252.6	78.1	145.8	593.2	0.0	214.3	38.1	408.7	11.9
1972	727.5	57.6	158.5	47.3	669.7	22.3	140.9	243.3	58.6	162.0	643.3	0.0	264.3	34.3	329.6	31.5
1973	758.3	57.9	160.4	66.9	646.8	21.4	148.4	244.5	63.2	168.5	483.8	0.0	480.2	28.7	402.6	42.6
1974	752.1	60.3	146.1	60.6	611.4	19.4	145.1	241.4	65.3	156.8	312.3	0.0	409.1	41.3	484.7	53.2
1975	703.6	52.2	157.1	56.4	666.7	14.1	151.0	253.7	45.3	197.4	291.9	0.0	494.0	66.9	417.3	70.2
1976	658.4	56.9	168.1	66.6	630.4	14.2	156.1	231.1	44.2	207.1	313.0	0.0	612.5	53.1	240.6	78.2
1977	660.4	46.7	174.6	75.1	568.9	14.5	158.8	239.0	51.6	207.5	380.2	0.0	797.5	87.4	148.7	77.4
1978	512.6	47.6	176.8	67.8	565.1	20.7	168.3	232.9	54.8	209.2	320.3	0.0	634.6	83.8	385.5	64.3
1979	522.6	44.2	184.6	68.5	619.1	25.1	178.9	270.9	51.3	214.4	469.1	0.0	634.4	95.3	351.2	83.8
1980	507.4	78.9	177.0	66.1	552.4	18.7	177.5	269.4	75.5	216.6	545.8	0.0	408.7	53.7	424.5	109.8
1981	482.9	68.1	169.1	78.4	509.9	16.8	180.1	247.4	107.7	231.4	691.4	0.0	289.0	35.4	311.2	123.0
1982	379.7	51.8	161.4	69.4	562.5	16.6	177.0	247.3	72.4	226.6	562.1	0.0	101.3	41.4	525.1	104.7
1983	359.3	55.1	164.3	32.0	519.0	20.0	183.8	224.7	56.4	214.8	487.4	0.0	70.2	61.2	598.7	129.3
1984	437.3	138.9	175.0	36.5	490.0	17.3	192.9	199.1	65.9	243.7	601.7	0.0	29.7	153.4	451.2	163.6
1985	449.5	117.8	180.7	44.0	547.8	20.6	196.2	212.9	35.3	251.2	700.3	0.0	30.8	213.3	373.7	195.6
1986	443.3	94.6	180.4	42.5	481.3	17.4	196.3	189.5	51.5	255.1	464.2	0.0	35.5	283.1	472.6	215.2
1987	570.7	91.6	185.6	44.9	516.6	21.3	206.0	218.4	63.6	265.6	667.8	0.0	22.9	327.4	336.6	225.4
1988	500.8	55.1	187.6	50.7	511.5	23.1	220.5	255.5	55.5	275.6	572.8	0.0	79.3	331.6	317.6	213.3
1989	546.4	17.0	189.7	57.7	532.7	25.1	219.6	268.4	45.3	286.5	538.4	0.0	96.5	348.7	348.2	193.1
1990	606.5	11.7	190.7	64.7	530.8	22.7	227.2	294.1	46.2	301.5	471.5	0.0	46.2	349.2	294.2	177.8
1991	725.7	11.1	191.7	63.0	522.3	26.7	225.2	295.3	43.9	293.9	461.6	0.0	6.5	338.8	282.9	165.9
1992	705.7	11.9	194.8	64.8	492.7	18.8	232.4	292.9	22.9	299.9	583.1	0.0	3.7	376.3	244.2	165.6

Table US-5b: California Fuel Shares (%)

	Industrial				Residential			Commercial			Power Generation					
Year	NG	R	E	C	NG	O	E	NG	O	E	NG	C	O	N	H	G
1970	67.3	14.4	12.9	5.3	80.0	3.2	16.8	52.1	15.2	32.7	53.5	0.0	10.9	2.7	31.9	0.9
1971	67.2	14.4	13.7	4.7	80.8	3.0	16.2	53.9	15.0	31.1	46.8	0.0	16.9	3.0	32.3	0.9
1972	65.9	15.5	14.4	4.3	80.4	2.7	16.9	53.4	11.1	35.5	49.4	0.0	20.3	2.6	25.3	2.4
1973	64.4	16.2	13.6	5.7	79.2	2.6	18.2	52.2	11.8	36.0	33.6	0.0	33.4	2.0	28.0	3.0
1974	66.1	15.7	12.8	5.3	78.8	2.5	18.7	53.0	12.5	34.5	24.0	0.0	31.4	3.2	37.3	4.1
1975	64.6	15.8	14.4	5.2	80.1	1.7	18.2	52.0	7.5	40.5	21.8	0.0	36.9	5.0	31.1	5.2
1976	61.4	16.8	15.7	6.2	78.7	1.8	19.5	49.0	7.1	43.9	24.1	0.0	47.2	4.1	18.5	6.0
1977	60.8	16.2	16.1	6.9	76.6	2.0	21.4	49.3	7.9	42.8	25.5	0.0	53.5	5.9	10.0	5.2
1978	54.2	20.0	18.7	7.2	74.9	2.7	22.3	48.4	8.0	43.5	21.5	0.0	42.6	5.6	25.9	4.3
1979	52.2	22.6	18.4	6.8	75.2	3.1	21.7	51.7	7.3	41.0	28.7	0.0	38.8	5.8	21.5	5.1
1980	52.4	22.4	18.3	6.8	73.8	2.5	23.7	48.8	12.0	39.2	35.4	0.0	26.5	3.5	27.5	7.1
1981	51.3	22.4	18.0	8.3	72.1	2.4	25.5	42.8	17.2	40.0	47.7	0.0	19.9	2.4	21.5	8.5
1982	46.3	25.5	19.7	8.5	74.4	2.2	23.4	45.9	12.0	42.1	42.1	0.0	7.6	3.1	39.3	7.8
1983	48.4	25.2	22.1	4.3	71.8	2.8	25.4	46.2	9.7	44.1	36.2	0.0	5.2	4.5	44.5	9.6
1984	46.0	31.7	18.4	3.8	70.0	2.5	27.5	39.8	11.6	48.7	43.0	0.0	2.1	11.0	32.2	11.7
1985	47.6	28.7	19.1	4.7	71.7	2.7	25.7	43.4	5.3	51.2	46.3	0.0	2.0	14.1	24.7	12.9
1986	49.2	26.0	20.0	4.7	69.2	2.5	28.2	38.9	8.7	52.4	31.6	0.0	2.4	19.2	32.1	14.6
1987	54.1	24.1	17.6	4.3	69.4	2.9	27.7	40.9	9.4	49.7	42.3	0.0	1.4	20.7	21.3	14.3
1988	52.8	22.1	19.8	5.3	67.7	3.1	29.2	44.3	8.0	47.7	37.8	0.0	5.2	21.9	21.0	14.1
1989	56.6	17.8	19.6	6.0	68.5	3.2	28.2	45.4	6.1	48.5	35.3	0.0	6.3	22.9	22.8	12.7
1990	58.9	16.3	18.5	6.3	68.0	2.9	29.1	46.6	5.7	47.7	35.2	0.0	3.5	26.1	22.0	13.3
1991	65.4	11.7	17.3	5.7	67.5	3.5	29.1	47.3	5.6	47.1	36.8	0.0	0.5	27.0	22.5	13.2
1992	47.1	35.6	13.0	4.3	66.2	2.5	31.2	48.2	2.5	49.3	42.5	0.0	0.3	27.4	17.8	12.1

Key: NG–natural gas; R–residual fuel oil; E–electricity; C–coal; O–oil; N–nuclear; H–hydro; G–geothermal
Source: US DOE/EIA, *State Energy Data Report*, 1992, Consumption Estimates

Table US-6a: Illinois Fuel Consumption (Trillions of BTUs)

	Industrial				Residential			Commercial			Power Generation				
Year	NG	R	E	C	NG	O	E	NG	O	E	NG	C	O	N	H
1970	390.5	247.9	87.5	260.2	450.1	109.9	76.9	198.3	78.8	76.6	135.7	608.9	35.8	27.6	1.5
1971	417.3	221.2	91.6	216.0	474.2	110.9	81.8	215.7	62.8	80.3	129.0	582.3	68.8	47.4	1.2
1972	408.8	267.4	101.7	207.2	499.9	120.5	86.9	230.1	66.3	84.4	74.8	613.8	83.3	141.0	1.4
1973	434.8	271.4	111.1	184.3	455.9	117.1	92.7	223.5	65.3	91.3	40.6	677.4	72.2	218.6	1.2
1974	419.0	268.6	110.1	184.4	472.2	111.3	91.7	221.0	65.7	90.7	44.1	667.0	72.1	218.7	1.1
1975	361.4	260.2	103.5	172.9	491.0	113.1	90.0	221.3	63.8	95.9	35.2	655.4	67.8	245.8	1.1
1976	382.8	266.6	109.8	154.6	520.6	125.5	89.8	252.8	63.0	99.9	31.4	686.9	66.0	292.2	1.2
1977	380.2	267.1	115.3	143.8	534.5	120.3	96.1	250.5	61.2	104.6	14.8	699.1	83.5	307.4	1.1
1978	373.3	265.2	122.2	134.3	530.0	126.1	99.3	256.5	63.1	110.2	23.2	688.8	106.1	360.2	1.2
1979	368.7	295.9	122.8	129.0	507.7	70.0	99.9	243.0	49.2	110.0	32.2	709.1	98.9	298.8	1.2
1980	357.0	251.7	120.0	127.7	489.0	36.3	102.1	233.2	36.8	107.8	19.6	712.7	85.1	302.6	1.3
1981	352.7	211.3	115.0	116.3	476.7	30.8	96.8	227.9	39.8	112.1	13.5	674.7	63.6	325.2	1.2
1982	298.8	169.3	103.8	113.4	468.7	31.9	97.6	223.6	33.0	112.8	10.6	657.5	48.4	305.9	1.1
1983	293.0	159.2	110.4	124.9	448.3	29.4	104.9	213.3	40.3	115.2	12.3	713.0	39.7	305.6	1.2
1984	316.1	149.2	116.1	144.0	498.8	25.9	103.8	241.5	38.7	116.5	6.1	679.1	30.6	379.2	1.3
1985	296.3	140.5	123.4	142.3	464.5	29.0	102.3	222.1	31.0	111.3	6.0	662.8	18.7	422.9	1.2
1986	273.5	178.6	125.5	148.2	446.2	25.0	105.7	209.3	22.7	114.8	6.2	650.0	28.9	460.2	1.3
1987	268.6	211.6	124.8	158.5	414.0	24.0	109.2	193.9	20.6	122.4	3.3	618.2	22.8	540.9	0.9
1988	274.1	216.0	129.5	171.6	470.7	24.7	115.9	219.1	20.2	128.8	5.8	567.5	15.8	743.1	0.5
1989	285.0	84.2	131.3	155.8	511.0	23.3	110.5	200.5	14.7	130.0	7.1	551.5	12.3	802.4	0.5
1990	281.8	85.9	134.1	150.8	451.9	19.2	112.2	204.7	15.4	133.2	9.3	591.1	13.1	767.8	0.6
1991	308.6	85.6	135.5	156.8	475.8	21.5	122.7	197.5	14.8	139.3	13.1	595.1	18.9	771.8	0.5
1992	305.9	80.5	139.5	147.1	483.9	19.4	110.4	200.5	15.3	132.7	9.4	539.0	14.1	787.4	0.5

Table US-6b: Illinois Fuel Shares (%)

	Industrial				Residential			Commercial			Power Generation				
Year	NG	R	E	C	NG	O	E	NG	O	E	NG	C	O	N	H
1970	39.6	25.1	8.9	26.4	68.8	16.8	11.7	51.6	19.8	20.0	16.8	75.2	4.4	3.4	0.2
1971	44.1	23.4	9.7	22.8	69.5	16.2	12.0	56.0	15.6	20.8	15.6	70.3	8.3	5.7	0.1
1972	41.5	27.1	10.3	21.0	69.6	16.8	12.1	57.8	16.0	21.2	8.2	67.1	9.1	15.4	0.2
1973	43.4	27.1	11.1	18.4	67.7	17.4	13.8	57.1	15.8	23.3	4.0	67.1	7.1	21.6	0.1
1974	42.7	27.3	11.2	18.8	69.1	16.3	13.4	56.7	16.1	23.3	4.4	66.5	7.2	21.8	0.1
1975	40.2	29.0	11.5	19.3	70.1	16.1	12.9	57.0	15.5	24.7	3.5	65.2	6.7	24.4	0.1
1976	41.9	29.2	12.0	16.9	70.1	16.9	12.1	59.4	13.9	23.5	2.9	63.7	6.1	27.1	0.1
1977	41.9	29.5	12.7	15.9	70.6	15.9	12.7	59.1	13.5	24.7	1.3	63.2	7.6	27.8	0.1
1978	41.7	29.6	13.6	15.0	69.6	16.6	13.0	58.6	13.5	25.2	2.0	58.4	9.0	30.5	0.1
1979	40.2	32.3	13.4	14.1	74.6	10.3	14.7	60.4	11.1	27.3	2.8	62.2	8.7	26.2	0.1
1980	41.7	29.4	14.0	14.9	77.8	5.8	16.2	62.2	8.4	28.7	1.8	63.6	7.6	27.0	0.1
1981	44.4	26.6	14.5	14.6	78.6	5.1	16.0	60.3	9.0	29.7	1.2	62.6	5.9	30.2	0.1
1982	43.6	24.7	15.2	16.5	78.0	5.3	16.2	60.6	7.4	30.6	1.0	64.2	4.7	29.9	0.1
1983	42.6	23.2	16.1	18.2	76.5	5.0	17.9	57.3	10.0	30.9	1.1	66.5	3.7	28.5	0.1
1984	43.6	20.6	16.0	19.9	78.9	4.1	16.4	60.3	9.1	29.1	0.6	61.9	2.8	34.6	0.1
1985	42.2	20.0	17.6	20.3	77.7	4.9	17.1	60.8	7.7	30.5	0.5	59.6	1.7	38.0	0.1
1986	37.7	24.6	17.3	20.4	77.1	4.3	18.2	60.2	5.7	33.0	0.5	56.7	2.5	40.1	0.1
1987	35.2	27.7	16.3	20.8	75.4	4.4	19.9	57.3	5.2	36.2	0.3	52.1	1.9	45.6	0.1
1988	34.6	27.3	16.4	21.7	76.7	4.0	18.9	59.3	4.7	34.9	0.4	42.6	1.2	55.8	0.0
1989	43.4	12.8	20.0	23.7	79.0	3.6	17.1	57.7	3.5	37.4	0.5	40.1	0.9	58.4	0.0
1990	43.2	13.2	20.5	23.1	77.2	3.3	19.2	57.8	3.5	37.6	0.7	42.8	0.9	55.6	0.0
1991	45.0	12.5	19.7	22.8	76.5	3.5	19.7	55.9	3.6	39.4	0.9	42.5	1.4	55.2	0.0
1992	45.4	12.0	20.7	21.9	78.6	3.2	17.9	57.2	3.8	37.8	0.7	39.9	1.0	58.3	0.0

Note: Residential and Commercial figures exclude coal. Industrial oil total excludes asphalt/road oil, kerosene, lubricants, motor gasoline and other.

Key: NG–natural gas; R–residual fuel oil; E–electricity; C–coal; O–oil; N–nuclear; H–hydro
Source: US DOE/EIA, *State Energy Data Report*, 1992, Consumption Estimates