The Impact of Cheap Oil on Gas Markets

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ABBREVIATIONS

bcf	billion cubic feet
b/d	barrels per day
boe/d	barrels of oil equivalent per day
Btu	British thermal units
c.i.f.	cost, insurance and freight
gWh	gigawatt hours
kWh	kilowatt hours
LNG	Liquefied natural gas
mtoe	million tonnes of oil equivalent
RAC	refiner's acquisition cost
UEG	utility electric generation

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1 INTRODUCTION

It is often assumed that oil can increase its share of energy markets fairly quickly if its price drops relative to competing fuels. Since oil is already the dominant fuel in the transportation sector, gains at the expense of other fuels must come from elsewhere. The slow pace of fuel conversion decisions in the residential and commercial sectors makes it unlikely that price changes will have any perceptible impact in those sectors in the short-run. Thus it is logical to expect that, if changed oil price signals are to have any short-run impact at all, they are most likely to make themselves felt in the industrial and power generation sectors.

The oil price collapse of 1986 provided an excellent laboratory experiment to test the response of markets in the short run to a dramatic change in relative fuel prices. Between early January and late July of that year, when oil prices hit bottom, cargo prices of various grades of residual fuel oil in the US Gulf Coast, New York Harbor, Rotterdam, Italy, and Singapore markets declined between 50 per cent and 70 per cent. If ever it were possible to test the hypothesis that oil could gain quickly at the expense of alternative fuels, it should have been during that six-month period. This analysis examines the results of that experiment in competitive fuel markets and draws conclusions about their longer-term implications.

The increased market penetration which oil was able to demonstrate as a result of its dramatic price drop was not impressive. In comparing six market sectors – oil demand (for all products) in the United States, Europe, and Japan for both industry and power generation – the composite gain in demand for 1986 over 1985 was less than 70 thousand boe/d. Furthermore, total oil consumption actually decreased in 1986 relative to 1985 in all sectors except for power generation in the USA and Japan. Also, industrial oil consumption declined in the face of lower oil prices throughout the OECD although industrial residual fuel oil did show a gain in the USA. These gains were anything but permanent. The composite decline of 114 thousand boe/d for the three OECD regions between 1987 and 1986 exceeded the 67 thousand

boe/d gain in 1986 despite an only partial recovery of oil prices. Figure 1.1 summarizes these gains and losses in total oil consumption for 1986-85 and 1987-86.

The inability of oil to hold its gains indicates that it was the slow rate at which competitive fuels adjusted to the new oil price levels, rather than the establishment of any lasting oil price advantage, which led to the 1986 increase and the subsequent 1987 decline. If this is indeed the case, the obvious questions are (1) 'Why couldn't oil hold its gains?' and (2) 'Will future oil-induced price competition be as ineffective as it was in 1986?'

To begin with, let us briefly describe the principal targets of oil price competition in large nuclear power stations. The very high investment costs per installed kilowatt are justified on the basis of very low uranium fuel costs; hence nuclear power exhibits far lower marginal fuel operating costs than its fossil fuel competitors. While in theory low oil prices might make it attractive to run the oil-fired units at higher capacity factors, the very low running costs of nuclear generators make existing nuclear power plants almost immune to short-run price competition from oil.

Of the three fossil fuels, the installed cost of oil-burning equipment is commonly slightly higher than that of gas but much lower than that of coal. Where coal costs are low and the coal-burning equipment is modern and efficient, oil may also find it very difficult to displace coal at the level of price competition experienced in 1986. However, coal may be somewhat vulnerable in areas where coal costs are high and/or equipment is old. This is true in parts of Europe, for example.

Gas can frequently command a premium based on its clean burning characteristics and its ease of control. Where efficient gas-only equipment has been installed, it may be difficult or costly to switch to oil. In some cases higher priced distillate fuel oil rather than residual fuel oil may be the only substitute. Thus gas may in many cases be able to retain its markets and even its price premium in the face of oil price competition.

However, in many areas gas is burned in dual-fired boilers utilizing residual fuel oil as the alternate fuel. In such cases gas may be extremely vulnerable to oil price competition and might be expected to lose market share rather quickly in the face of an oil price collapse.

The data show that, despite an unprecedented price decline, oil did very little to displace gas from its markets. The explanation lies in the fact that the marginal costs of producing, transporting, and delivering gas are very low. The production and delivery system shows a pattern of very high investment costs and very low cash operating costs which is similar to that of nuclear power. Exploration and development, and the transportation of natural gas are highly capital-intensive, and thus by comparison with oil wells, gas wells usually have much lower variable operating costs relative to their sunk costs for exploration and development. The producer, therefore, often prefers to keep producing gas, even at a paper loss, since his contribution to cash flow will remain positive if he meets the competitive price. The oil price collapse forced the shut-in of substantial stripper oil well production in the United States, but there was almost no perceptible effect on gas deliverability or production as gas prices tracked oil prices downwards.

But it is the economics of transportation to market which perhaps most insulates gas from oil price competition. Gas transportation, either by pipeline or by LNG tanker, is much more expensive than oil transportation, and most of the costs represent investment in facilities rather than cash operating costs. It may be difficult to demonstrate the investment feasibility of a new gas pipeline or LNG project and to finance it in the face of price weakness, but once the project is in place, it is very difficult to justify shutting it down because of price competition. Most of these capital-intensive gas transportation projects cannot be built without revenue guarantees from their customers, such as take-or-pay clauses or minimum offtake agreements. They thus commonly continue to operate despite the appearance of a more attractive competitively-priced alternative in oil.

The behaviour of Japanese gas markets in 1986 illustrates the point. Virtually all the gas sold in Japan is imported as LNG from Abu Dhabi, Alaska, Australia, Brunei, Indonesia, or Malaysia. Since the utility electric generation (UEG) and gas distribution company importers are committed on long-term contracts, the oil price collapse of 1986 had almost no visible effect on gas demand. While the oil price weakness spread quickly to gas because of the use of oil-based escalators in the purchase contracts, and difficult negotiations over the

interpretation of the pricing clauses ensued, the gas never stopped flowing. There is much greater flexibility to switch from gas to oil in the USA on the basis of price since the Federal Energy Regulatory Commission (FERC) is attempting to oversee the development of market-responsive pricing. However, the tendency of producers, transmission companies, and local distributors to meet oil price competition and retain the contribution to cash flow rather than forfeit the load, produced much the same effect on gas market share in the USA in 1986.

There seems little reason to anticipate a change in the propensity for existing gas supplies to meet short-run oil price competition in any of these markets rather than concede market share. The principal gains which oil might achieve at the expense of gas are thus likely to be concentrated in the longer term. Competition with low-priced oil would have a negative influence on gas investment levels and serve to restrict long-term gas supply as a result.

The marginal gas supply throughout much of the OECD is imported. In countries such as Japan, Sweden, Spain, or Portugal, gas will only be able to increase its share of the energy market if substantial new investments in pipeline and/or LNG facilities are made. Even in countries with significant potential domestic gas resources, such as the USA or the UK, heavy investment in exploration and production together with added pipeline infrastructure will be required if gas is to increase its market share. It is important to recognize, however, that the pertinent level of prices is that which the investor perceives will apply several years into the future when a gas project finally comes on line, rather than the one which applies at the time. Thus it is important that investors view the low oil price levels as a chronic problem rather than a temporary phenomenon if oil is to make any significant gain. None the less, the appearance of weak or volatile oil pricing in the near term may still influence the investor's confidence in future price stability to the detriment of new gas supply or transportation investment.

In 1986, following the oil price collapse, the rapidly growing market for LNG imports into Japan appeared to have come to a halt. With somewhat higher oil prices it has now resumed its growth, primarily through incremental expansion of existing Indonesian and Malaysian facilities. Optimism about new greenfield projects in higher-cost areas, such as Australia,

Alaska, or the Middle East, remains subdued at these price levels, however.

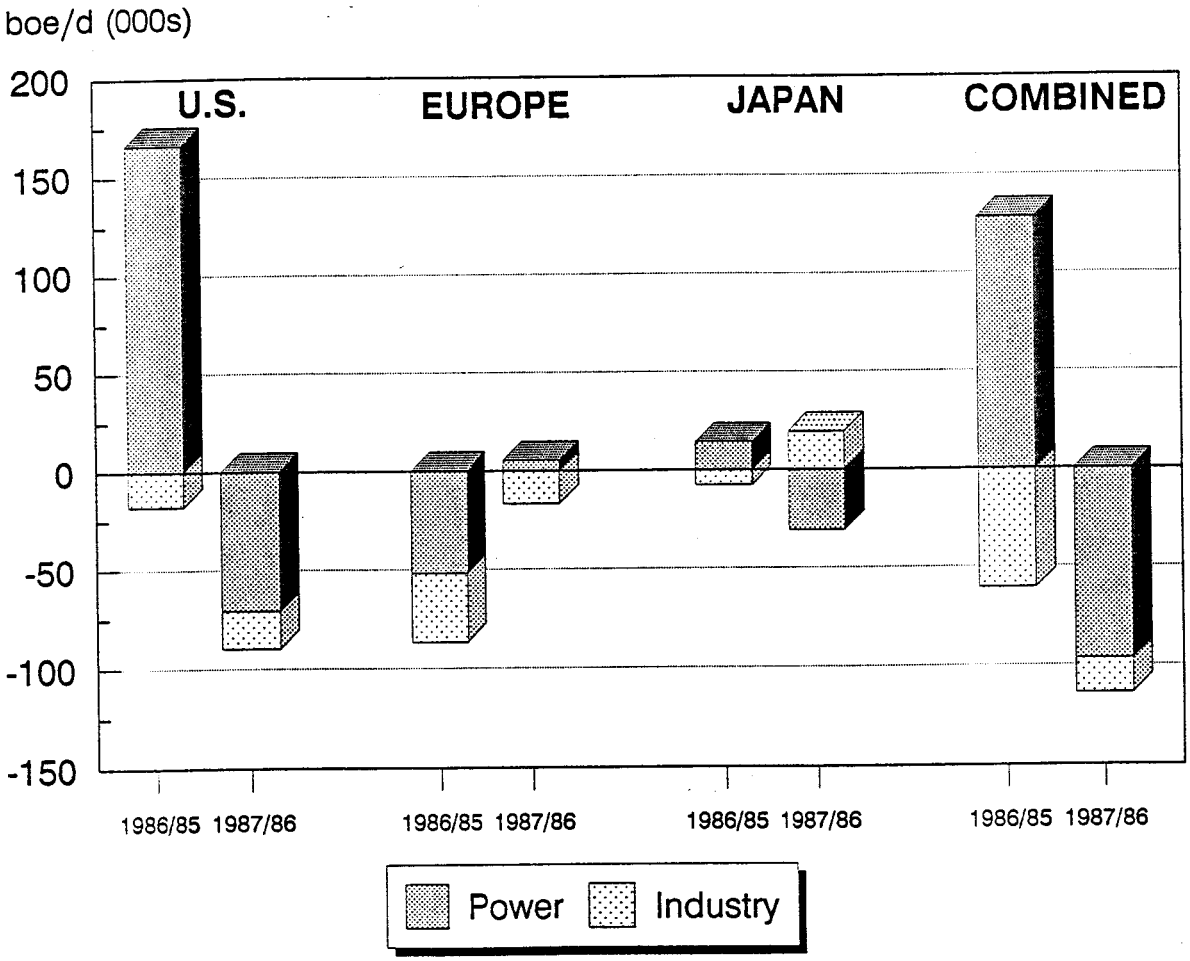
Not only would a sustained period of low oil prices inhibit investment in new gas supplies, but by stimulating economic growth in the OECD, it would provide a secondary improvement in the prospects for oil. There is a growing expectation throughout the OECD that demand for natural gas is likely to increase substantially. This is in part due to the safety and environmental problems of nuclear power and coal. But it is also a result of the improved energy efficiencies and lower capital cost which gas-firing of combined cycle (a combination of gas turbine and steam turbine power generation) and process steam/power cogeneration projects make possible. Any increase in economic activity which stimulates growth would normally benefit gas still further. But if prolonged low oil prices inhibit additional gas investment, oil might be the one to gain.

In conclusion, oil's ability to displace gas markets through price competition is limited in the short term by the low marginal costs of gas supply. While the USA, the European countries, and Japan all have individual patterns of gas use and gas-to-oil competition, the net result of weak oil pricing in all of these markets is remarkably similar. We see little reason for this to change. The greatest prospects for improved oil market share at the expense of natural gas is a long-run effect through the price effect of new gas investment.

FIGURE 1.1

CHANGE IN OIL CONSUMPTION IN INDUSTRY AND POWER GENERATION

1986/85 & 1987/86



Source: JAI estimates based on OECD data.

2 UNITED STATES

2.1 The Influence of Oil Prices on US Oil Demand

The collapse of oil prices in 1986 led to a rapid increase in US oil imports. Total net imports of crude oil and petroleum products rose from 4,286 thousand b/d in 1985 to 5,439 thousand b/d in 1986, an increase of 1,152 thousand b/d. This dramatic change in import levels can be attributed to several factors which were set in motion by the price collapse. The price decline severely inhibited exploration and development activity with the result that domestic production has steadily declined since that time. But product demand was also stimulated so that total oil consumption has been rising since 1986. Demand for gasoline, distillates, and other light products has continued to grow, but the increase in demand for residual fuel oil was largely temporary in nature, falling back again in 1987 when oil prices recovered. Table 2.1 summarizes these changes in import levels since 1985 by sector.

Since 1985 US oil imports have been increasing at an average annual rate of 689 thousand b/d (757 thousand b/d after adjusting for stock changes and other transient influences). Roughly one third of the change can be attributed to declining production. Another third represents an increase in gasoline and distillate, while other products account for the remaining third. Of these other products, most of the increase is accounted for by such products as LPG and petrochemical feedstocks, while the contribution of residual fuel oil over the period has been comparatively small.

2.2 Switching from Gas to Residual Fuel Oil

Over the three-year period, residual fuel oil contributed on average only about 42 thousand b/d per year of additional load on oil supply. Thus the portion of the barrel which competes most directly (in dual-fired boilers) with natural gas has shown no sustained benefit from the lower oil price levels prevailing since 1986. The increase in residual fuel oil demand between 1986 and 1985 was a substantial 216 thousand b/d, but the price recovery in 1987 caused residual fuel oil to give up all but 62

thousand b/d of its gains (it dropped 154 thousand b/d from 1986 to 1987).

The portion of the US demand for residual fuel oil which has been most responsive to price changes is the demand by the utility electric generation (UEG) sector. Table 2.2 shows the extent of the changes in power generation, bunkering, and other loads which have taken place over the three-year period on the average and for the year-to-year changes of 1986-85 and 1987-86.

The changes shown in Table 2.2 are based on year-to-year or period-to-period comparisons and are potentially different from an answer which an analyst might get with a somewhat different definition. For example, based on an industry questionnaire, the American Gas Association (AGA) contends that losses from gas to residual fuel oil in the industrial sector during the 1986 price decline were of the order of 238 bcf (107 thousand boe/d). While AGA concedes that residual fuel oil use in industry did not increase in 1986 over 1985, it argues that its consumption trend was downward and therefore oil price weakness, in reversing the decline, actually increased oil's market share.

There are roughly four types of UEG oil/gas utilization situations in which low-priced oil can penetrate gas markets.

(a) One potential opportunity exists in oil-only units. The East Coast UEG market has traditionally relied much more heavily on residual fuel oil than has any other section of the country. Many of these facilities have oil capability only and thus their use tends to continue regardless of oil price levels. However, since the US utilities are interconnected in regional power pools which dispatch units based on lowest incremental generating costs, a fall in oil prices can increase the utilization of oil units as they move into a priority generating position relative to other capacity. While the units displaced would most commonly be gas-fired since the marginal costs of nuclear and coal units are usually low, there is some evidence that the very low oil prices in the summer of 1986 did displace coal. Most US utilities are summer peaking for air conditioning load and the oldest – and often least efficient – coal units are likely to be dispatched in mid-summer.

(b) Another large portion of the market is dual-fired with oil and gas, and therefore can conceivably switch from gas to oil if oil prices decline significantly. However, dual-

fired units in the Northeast tend to be seasonally interruptible and thus will switch from gas to oil in the winter regardless of price. While an oil price decline in the summer, when they are being gas-fired, does represent a significant potential oil load, off-peak gas pricing is frequently so favourable for these seasonal units that it may be difficult for oil to displace gas.

(c) The third type of oil/gas generation represents units in coastal areas which are dual-fired but commonly run on natural gas the year around. However, since they have access to sources of residual fuel oil (commonly through deepwater import terminals) they may be very sensitive to oil prices and thus represent prime targets for price-induced switching to oil. Although some of these units are located on the Gulf and Atlantic coasts, they are most common in California where the alternate fuel is low sulpher residual fuel oil usually based on Indonesian crudes.

(d) Finally, a large portion of US gas-fired generating capacity in the US Southwest is nominally convertible to oil-firing, but since it is located near sources of natural gas, it has never been under pressure to provide alternate residual fuel oil capability. Although technically dual-fired, the alternate fuel is often distillate for emergency back-up. Thus, it is doubtful whether it is likely to be switched to oil-firing on the basis of price.

Table 2.3 summarizes generating capacity which is either gas or oil-capable by census region. The next-to-last column indicates the maximum potential oil consumption assuming the units operate at a 50 per cent capacity factor at a 10,000 Btu/kWh heat rate. While most of the gas-capable capacity in the US Southwest (West South Central Census region) is nominally dual-fired, much of it is based on distillate and the switching capability is rarely utilized. In our analysis we treat the distillate-capable capacity as if it is gas-only. The final column shows December 1988 oil consumption by region and thus the extent to which residual fuel oil capability was utilized.

Table 2.4 summarizes the increases in UEG oil demand (including distillate) by census region from 1985 to 1986 when oil was attempting to carve out a market share against gas. The gains were concentrated in the South Atlantic, particularly

Florida, as well as the New England and Middle Atlantic states. All these locations have access to deepwater terminals and therefore imported residual fuel oil.

The UEG market in California is in many ways the most sensitive to oil/gas price competition of any market in the USA. The state has no coal of its own but its crude oil production has always been heavy with a high residual fuel oil yield. As a result, power generation in the state has been based on hydroelectric generation subject to its availability and thermal generation based on dual-fired gas/residual fuel oil units. More recently the state has also relied on nuclear power and on power delivered from other regions. As air pollution concerns have mounted, residual oil from California crude oils has been largely unacceptable and residual fuel oil refined from low sulpher Indonesian crude oil in Indonesia, Singapore, or Hawaii has been the competitor for gas.

Gas-firing by both utilities and large industries has always been required to be dual-fuelled because of the gas supply risks inherent in California's location at the end of gas pipelines. Thus the nature of the market provides a means of translating international oil price weakness quickly and directly to gas.

In the early March-April 1986 price collapse, oil quickly became cheaper than gas and there was some switching to oil. When prices bottomed out in August of 1986, the switching away from gas was at its peak, but within a month as oil prices strengthened once again the UEG market quickly switched back to gas. Oil's gains were therefore very short-lived. On the year the net gain by oil was only 3000 BPD. Gas prices, however, fell dramatically to retain its markets. Thus marginal costs – which were very low – prevailed over average prices which were comparatively high at the start of the period. Oil essentially gained nothing from its pricing.

2.3 Oil to Gas Price Competition

With the significant decline in US natural gas demand (demand in 1986 was 28 per cent less than in the peak year of 1972) the country has been experiencing a continuing surplus of deliverability, commonly known as the 'gas bubble'. At the same time, the thrust of regulatory policy has been to move the industry from its heavily-regulated status of the 1960s and 1970s toward partial deregulation and market-responsive pricing. The

implementation of this policy during a period of chronic oversupply has led, until quite recently, to gas-to-gas competition at prices well below oil-set levels.

Wellhead prices for natural gas under conditions of oil competition would be less than parity on the basis of heating value. The costs of gas transportation and distribution to the competitive burner-tip are higher than they are for oil. At the same time, the oil which most directly competes with gas under dual-fired boilers – residual fuel oil – sells at a discount per barrel below crude oil. Taking these factors into account, the rough level of gas prices at which oil and gas markets are in balance has been about 58 per cent of oil on a heating value basis. While this relationship is expected to be rising over time, it represents a good recent benchmark for determining when gas markets have been at risk to oil competition.

Figure 2.1 shows the oil and gas price history from 1985 to 1988 of spot gas prices in the Southwest compared to the average refiner's acquisition cost (RAC) of crude oil. Also shown is the 58 per cent price benchmark mentioned above. Prices were above this hypothetical clearing level during the early part of 1986 as oil prices fell more rapidly than gas prices. They have also been above the oil clearing line during parts of the winter of 1987-88 and 1988-89 as a combination of weaker oil prices and strengthening gas prices again introduced price competition. The strengthening gas prices are attributable to the gradual end of the 'gas bubble' and a tightening of markets.

Gas always loses some market share to oil during the winter heating season when large dual-fired UEG boilers are interrupted to permit service to the temperature-sensitive residential and commercial space heating market. However, during the periods when gas was priced above the 58 per cent of oil level the losses were higher than one would expect for the month in question. Figure 2.2 is a four-year history of monthly 'switching' in the UEG market, with the residual fuel oil use above seasonal normals outlined for those months in which gas prices were higher than 58 per cent of oil. Consumption is broken down into base UEG load, seasonal, and price-induced fuel switching. Since the price-induced fuel switching is narrowly defined to include only consumption above the four-year average in those months when gas prices exceeded 58 per cent of RAC oil prices, Figure 2.2 gives a somewhat lower level of implied price switching than the straight comparison of 1986 against 1985 in Table 2.2. The

amount of switching in 1986, considering that oil prices fell to less than half of initial price levels, is remarkably restrained. The recovery of the gas market share was also rapid given the magnitude of the oil price drop.

The more recent level of switching has been due both to strengthening gas prices (the end of the bubble) and weak oil prices. In that respect it is different from 1986 when oil prices fell away from gas prices and gas had to track them downward or lose market. The strengthening gas price pattern is also probably more representative of the way in which oil and gas will compete in the future than was the 1986 behaviour.

2.4 Switching in Industry

The year-to-year residual fuel oil consumption figures for 1986 relative to 1985 show virtually no increase in the industrial sector. While some would argue that low oil prices enabled industrial oil use to arrest a declining trend, it is hard to see from the 1986 experience that oil has a great deal to gain from greater penetration of industry markets with lower prices.

Industry reportedly has a substantial capacity to switch from gas to oil in dual-fired boiler installations. Thus the fact that this was hardly utilized during a greater than 50 per cent drop in oil prices during 1986 is significant. Table 2.5 shows the results of a Department of Energy study of fuel switching capability by industry for the year 1985. (A more recent study has concentrated almost exclusively on the ability of industry to switch away from oil.) The study of 1985 indicated a total capability to switch from natural gas to residual fuel oil of the equivalent of 875 thousand b/d. Five industries – Chemicals, Paper, Food, Petroleum, and Primary Metals – constituted 84 per cent of the total switching capability.

The study also summarized four broad regional patterns of capability. The 'South', which includes both the active oil competitive area of the South Atlantic census region as well as the relatively non-competitive West South Central, represented 45 per cent of the total. Since much of the chemical and petroleum industry is located in the Southwest near the source of natural gas, it is safe to assume that residual fuel oil would have at least as difficult a time competing with gas in industry as it does in power generation. The Northeast, where oil made some of its best UEG penetration, accounts for only about 14 per cent of

the residual fuel oil capability. The industrial heartland of the Midwest represents 27 per cent of the switching capability but is poorly placed to import low cost fuel oil.

There are several reasons why oil seems to have had a great deal of trouble improving its market share in industry despite lower 1986 prices. Many of the industrial plants which once had residual fuel oil capability have not used it in many years and the local refinery capacity to produce the fuel has succumbed to coking and other fuel oil reduction investments. The logistical system to deliver the fuel oil has largely atrophied as well. In some cases, such as California, tighter air quality restrictions limit the ability to burn locally-produced residual fuel oil. It is really not surprising that the greatest market penetration by fuel oil in 1986 was concentrated in large UEG stations with access to imported fuel oil through deep water terminals. Far less of the potential industrial market is so favourably located to receive residual fuel.

A second major reason for the inability to penetrate the industrial market has to do with competitive pricing. The fact that much of the industrial supply is delivered to smaller installations by truck or tank car means that it is much higher-priced to the ultimate consumer than the bulk deliveries which some UEG installations can receive. Even with a sharp reduction in crude oil prices, prices of fuel oil to the ultimate industrial user may not drop enough to promote switching.

The general conclusion, then, about industrial switching to oil on the basis of price is that it will be difficult to achieve substantial results in the short-term. How long it would take to redevelop the capability to supply and use residual fuel oil at levels which were once more common is problematical.

Table 2.1: Average Annual Increase in US Oil Imports. Thousand Barrels per Day.

	Average 1988/85	*Increase* 1986/85	*Increase* 1987/86
Increase in Oil Imports	689	1,152	476
Change in Stocks, etc.	68	(251)	190
Net Adjusted Increase	757	901	666
Decline in Crude Oil, NGL	275	347	281
Increase in Gasoline, Distillate	240	249	234
Other Products	199	89	304
Increase in Residual Fuel	42	216	(154)

Table 2.2: Average Annual Increase in US Residual Fuel Oil Consumption. Thousand Barrels per Day.

	Average 1988/85	*Increase* 1986/85	*Increase* 1987/86
Increase in Residual Fuel Oil	42	216	(154)
Increase in Bunkering	3	(7)	(7)
Increase in Industry, Other	(34)	19	(38)
Increase in UEG	73	204	(109)
Base Load Plants	59	182	(102)
Seasonal Units	14	22	(7)

Table 2.3: US Regional UEG Oil/Gas Capability.

	Oil Only MW	*Gas Only MW*	*Gas/ Oil MW*	*Total MW*	*Max Oil Use @ 50% LF b/d (000s) Residual Fuel Oil*	*12/88 Oil Use b/d (000s)*	*% Of Theoretical Max*
New England	8,250	0	2,872	11,122	212	218	102.7%
Middle Atlantic	12,108	2,078	10,012	24,198	422	356	84.4%
South Atlantic	12,865	2,862	12,709	28,436	488	209	42.9%
East North Central	5,892	4,354	1,136	11,382	134	24	17.8%
West North Central	3,921	5,881	2,372	12,174	120	2	1.6%
East South Central	62	535	3,318	3,915	65	5	7.6%
West South Central	0	32,633	27,085	59,718	517	6	1.1%
Mountain	892	2,021	3,402	6,315	82	6	7.7%
California	0	0	22,044	22,044	421	120	28.5%
Pacific Northwest	87	0	0	87	2	0	3.9%
TOTAL	44,077	50,364	84,950	179,391	2,463	946	38.4%

Note: May include coal capability, gas only may include distillate

Table 2.4: Increase in US UEG Oil Consumption[a]. 1986. Thousand Barrels per Day.

	Actual 1985	*Actual 1986*	*Increase*
New England	132	170	38
Middle Atlantic	172	211	39
South Atlantic	98	164	66
East North Central	15	20	5
West North Central	2	2	0
East South Central	2	5	3
West South Central	5	5	0
Mountain	3	3	0
Pacific Northwest	0	0	0
California	13	16	3
Total	442	597	155

Note: (a) Includes Distillate

Table 2.5: US Industrial Gas/Residual Fuel Oil Switching Capability. 1985.

Sic Code	*Gas Consumed bcf*	*Switchable to Residual Fuel Oil bcf*	*Switchable to Residual Fuel Oil b/d (000s)*
28 Chemicals & Allied Products	1,153	161	170
29 Petroleum & Coal Products	694	121	128
33 Primary Metal Industries	666	105	111
20 Food & Kindred Products	462	144	152
26 Paper & Allied Products	387	161	170
32 Stone, Clay & Glass Products	372	28	30
34 Fabricated Metal Products	169	11	12
37 Transportation Equipment	121	13	14
35 Machinery, Except Electrical	101	6	6
30 Rubber & Misc. Plastics Products	94	29	31
22 Textile Mill Products	89	33	35
All Other Industry	204	18	19
Total Manufacturing	4,512	830	875

Source: EIA

FIGURE 2.1

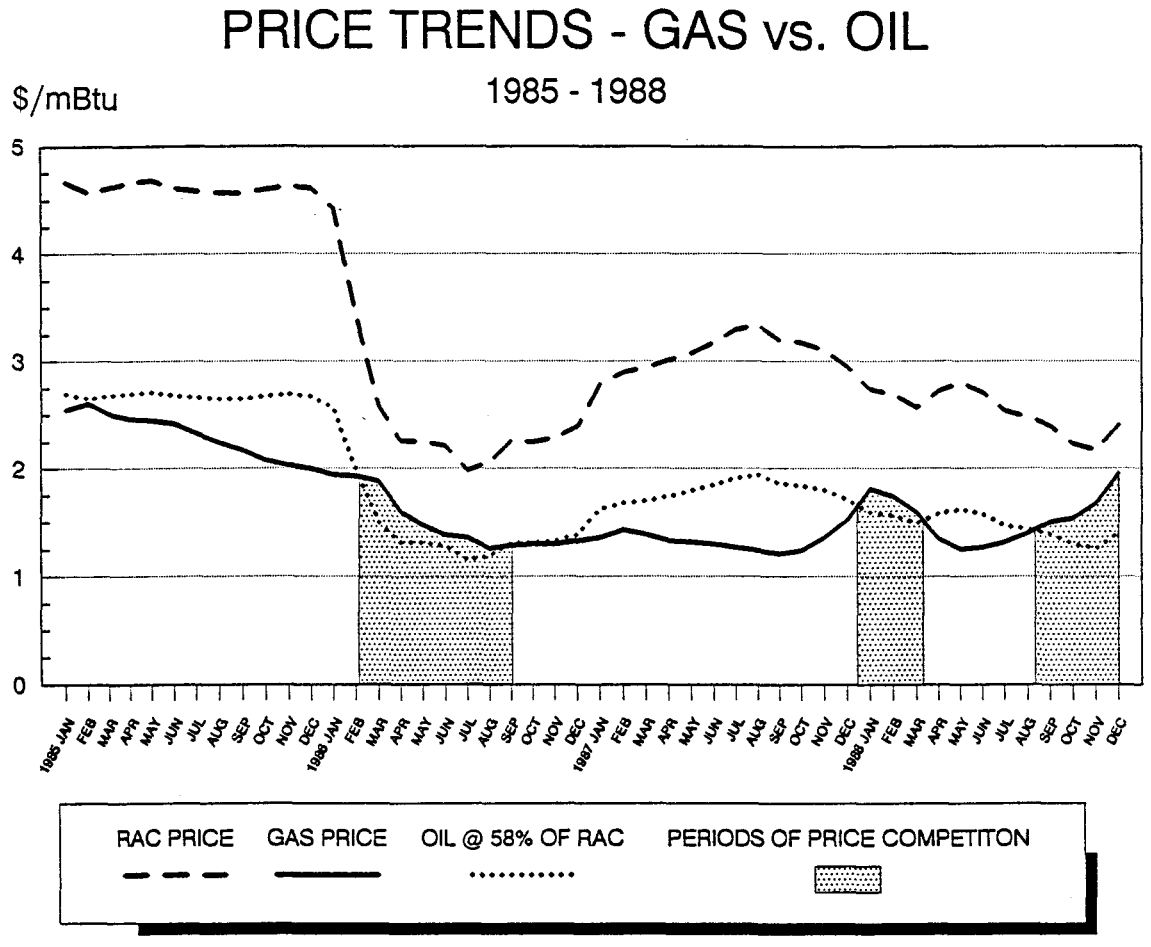
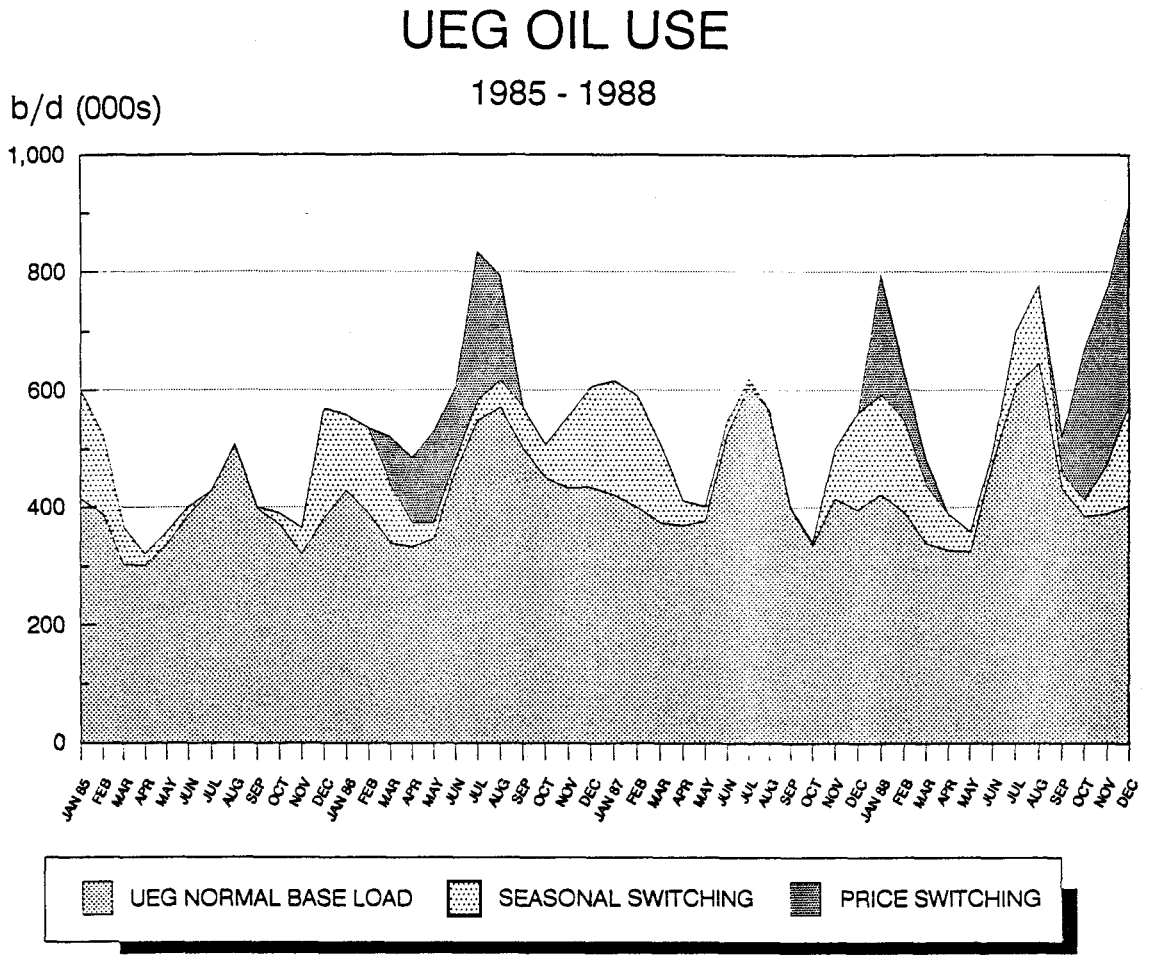

PRICE TRENDS - GAS vs. OIL
1985 - 1988
$/mBtu
5
4
3
2
1
0
1985 JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
1986 JAN
1987 JAN
1988 JAN
RAC PRICE
GAS PRICE
OIL @ 58% OF RAC
PERIODS OF PRICE COMPETITON

FIGURE 2.2


UEG OIL USE
1985 - 1988
b/d (000s)
1,000
800
600
400
200
0
JAN 85
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
JAN 86
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
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JAN 88
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
UEG NORMAL BASE LOAD
SEASONAL SWITCHING
PRICE SWITCHING

3 OECD EUROPE

3.1 The Differences between the European and US Switching Markets

In the United States, natural gas carved out a large market share of the industrial and power generation market during the period when gas was cheap and supplies were plentiful. Portions of that market – principally the large boilers remote from the gas supplies of the Southwest – were traditionally designed to be dual-fired with residual fuel oil. They thus provided a ready vehicle for oil/gas price competition.

The development of gas markets in Europe[1] took place much later. Oil had already made substantial inroads into the traditional coal dominance of industrial and power generation markets, and much of the equipment that was gas/oil fired in the USA was oil/coal fired in Europe. Thus the concentration of gas/oil dual-fired boilers never developed as it did in the United States.

Government policy in the EEC discouraged the use of gas for power generation. While gas-fired boilers were significant in the Netherlands, in much of the rest of Europe there was little gas used in the applications that are most important to switching in the USA. Eighty per cent of the gas-fired generation was concentrated in the Netherlands, Italy, and Germany. Even in Germany the gas share of market was only 5 per cent.

Other countries' policies frequently precluded gas use for electric power. France elected to emphasize nuclear power and there was therefore no role for gas-fired generation in that country. In the UK the Coal Board was anxious to promote coal use by the Central Electricity Generating Board. Thus the body of gas-switchable boiler load that supposedly makes US markets vulnerable to oil price competition never really developed in Europe.

Because coal was established as the chief competitor of oil in the European power generation market, the economics of replacement were quite different than in the United States. In

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[1] For simplicity, Europe indicates OECD Europe throughout this chapter.

general, gas-fired equipment has a much lower capital investment than does the comparable coal-fired equipment. Thus the economic trade-off is commonly that coal boilers have lower running costs and higher capital costs relative to gas. It is often more difficult for oil to compete on the margin with coal than with gas. While this is somewhat less true of Europe than it is of the USA, it still tends to apply. As a result, oil might be expected to have a harder time gaining market share through price in Europe than in the USA.

3.2 Potential Oil Displacement of Gas in Electric Power Generation

During the 1980s, a number of factors operating at a macro level have overwhelmed any price-induced fuel switching to oil for power generation. They include structural changes in generating capacity, government policies favouring particular fuels, and gas contracting practices. Although the dominant factor varies from country to country, and in the timing of its effect on oil use, certain trends are evident.

In general, the growth in nuclear power generation has been primarily responsible for pushing oil and gas-fired power plants into shoulder and peak operation. As Figure 3.1 demonstrates, nuclear power's share of total electricity generation in Europe has risen from only 12.3 per cent in 1980 to 30.5 per cent in 1987. In accommodating this growth, governments have followed policies designed to protect indigenous fuels such as coal in Germany and the UK. As a result, the shares of coal and hydropower in total generation are not much less now than they were in 1980. Together, they account for more than half of the electricity generated in Europe.

In contrast, power generation from oil and gas combined has fallen from 26.9 per cent of the total in 1980 to only 14.0 per cent in 1987. Furthermore, as Figure 3.2 demonstrates, virtually all of the downside swing has been taken by oil. Although gas use has declined slightly, the practice of tying gas contract prices to oil (and more recently coal) prices has largely protected it from any substantial loss of market share. In some countries, for example Italy and the Netherlands, gas has actually increased its share of power generation.

Of more importance is the fact that the gas share of total generation in Europe is so small – less than 6 per cent. Consequently, even if oil were to displace all the gas used to

generate both public and private electricity (including the mothballing of plants designed to burn gas only), it would add less than 550 thousand boe/d to demand. This compares to existing oil consumption for power generation of almost 800 thousand boe/d.

Some fuel switching into oil from gas and coal has occurred on occasions, but the volumes involved are small and the pattern of switching is not consistent, to judge from aggregate statistics. In Table 3.1, the amount of electricity generated from oil and gas relative to other sources in 1985, 1986 and 1987 is shown for Europe as a whole, and for selected countries. In Table 3.2, the generation figures are used to illustrate the proportion of total generation in each country represented by oil and gas combined, and the share of this combined generation held by oil.

Several points are worth noting. First, the five countries listed account for almost 90 per cent of the gas used in European power generation. Norway, Spain and Sweden are also substantial producers of electricity, but rely heavily on hydro and nuclear power (plus coal, in the case of Spain). Second, even where oil and gas-fired plants are used, with the exception of Italy and the Netherlands, they represent a small proportion of total generation. Third, in 1985, prior to the oil price collapse, oil already held a dominant share of the oil and gas combined generation in all countries except Germany and particularly the Netherlands. In Germany, oil substitution for gas is limited in part because more than half the power plants capable of burning natural gas are designed to burn gas only or coal/gas. However, in the Netherlands, more than 80 per cent of the generating capacity capable of burning natural gas can also burn oil. There, the competition for oil is an indigenous gas supply.

The amount of fuel switching to or from oil-fired generation which occurred at the time of the oil price drop in 1986 is shown in Table 3.3. For each country, the table shows the number of gigawatt hours (gWh) of electricity[2] more or less than would have been produced had oil (and other fuels) maintained the same share of the generating mix as in the previous year.

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[2] Based on conversion factors and thermal electric plant efficiencies used in OECD statistical publications 1,000 gWh of electricity generated is equivalent to gross fuel input of about 1.63/mboe.

As the table demonstrates, the long-term trend to displace oil by nuclear power overrides the effects of any price-induced fuel switching. With the exception of Germany, oil lost market share in 1986 relative to 1985, in all cases. (UK figures are influenced by the effects of the coal miners' strike which persisted into the first quarter of 1985, thereby inflating oil consumption in the base year.) In Germany, oil and gas both gained at the expense of nuclear power generation in 1986, although oil lost some market share again in 1987.

Given that Italy accounts for almost half of Europe's consumption of oil in power generation, it is worth noting that despite its fall in price oil lost market share to gas for 1986 as a whole. In 1987, both oil and gas gained share at the expense of nuclear and hydropower but, in percentage terms, gas gained most.

Recognizing that even during their trough in 1986, oil prices fluctuated relative to those of other fuels, it is worth examining power generation on a seasonal basis for evidence of fuel switching.

In general, European power plants operate in a winter peaking mode with the highest send-out of electricity occurring in January and the lowest in August of each year. Electric power generation from oil and gas-fired plants mirrors the seasonal movement in total generation, as shown in Figure 3.3. However, because oil and gas generation tends to provide more of the swing supply than coal and nuclear plants, the percentage rate of change in oil and gas consumption from one month to the next tends to be greater than for total generation. Allowing for monthly variations in total power generation, differences in the rate of change in oil versus gas-based generation may well reflect price-induced fuel switching between the two. (They could also result from plant openings, closures, and other factors.)

Although it is more difficult in Europe to develop comparable price data between gas and oil than it is in the United States, a comparison of relative price trends shows a tendency for the weak oil pricing of 1986 to spread to gas, albeit with some delays. Figure 3.4 compares a time series for border prices for gas between the Netherlands and West Germany with the average of highs and lows of Rotterdam barges for 1% S residual fuel oil. Since both price series are at the wholesale price level for different points in the chain of distribution,

their relative movement is more significant than their absolute level.

During 1986, c.i.f. heavy fuel oil prices hit their low point in July and rebounded somewhat in August. At that time, total public power generation excluding private supply for own use in the twelve-member EEC increased by almost 19 per cent from one month to the next. This seasonal increase is in line with that in other years. Compared to this, however, oil consumption for power generation jumped by 56 per cent in September over August.

This apparent fuel switching to oil was not at the expense of gas, however. Between August and September, gas consumption for power generation increased by 16 per cent, which is similar to the increase in total generation N thereby maintaining the gas share of the fuel mix. Rather, the increase in oil use occurred at the expense of other supplies.

In addition, the following points must be noted. First, despite the impressive increase in oil consumption in percentage terms, the volume attributable to fuel switching is small. For the EEC as a whole, the additional volume of oil used for power generation amounted to only 175 thousand boe/d more for the month of September than would have been consumed if oil had simply maintained its share of the generating mix. Furthermore, the total volume of oil used in that month was still less than the average monthly volume consumed during the following winter peak from November 1986 to March 1987.

Similarly, it is worth noting that despite impressive percentage increases in oil use in a number of countries, about 70 per cent of the fuel switching to oil occurred in the UK, which uses virtually no gas in power generation. The switching was also short-lived, as Figure 3.5 demonstrates.

The conclusion from this is that even with low prices, the potential for increasing oil demand through fuel switching from gas and coal in the European power sector is small. Allowing for private generation (which frequently utilizes non-switchable, internal by-product fuels such as refinery gas) and scaling up EEC figures to cover the whole of Europe, it appears that no more than 240 thousand boe/d could be gained.

As a result, other factors are likely to have a greater effect on oil use for power generation. Here the prospects are mixed. Following the Chernobyl disaster, some countries, such as Belgium, have scaled down their plans for nuclear power.

However, with growing concerns about pollution and a buyers' market for gas in Europe, natural gas appears likely to benefit most. In Italy, which has been heavily dependent on oil-fired generation hitherto, ENEL, the state electricity authority, has already begun a programme to build new 'polycombustible' power plants capable of burning oil, gas or coal at short notice. On the other hand, with the privatization of electricity supply in the UK, planned for 1990, the new generating companies are likely to be less constrained politically than the state-run CEGB to buy high cost British coal, potentially to the benefit of oil.

3.3 Potential Fuel Switching to Oil in Industry

The amount of gas consumed by the industrial sector in Europe is more than 2.5 times that used in power generation. This suggests that the potential for price-induced fuel switching is substantially greater. In practice, that may not be the case.

In power generation, fuel switching may occur in two ways. Power plants designed to burn gas only may be dropped from the generating mix in favour of higher utilization of oil-fired plants. In addition, oil may displace gas in dual-fired plants.

In industry, however, gas is used for process applications and as feedstock in addition to its use as a boiler fuel. There, factors other than relative fuel pricing come into play. For example, in glassmaking the flame characteristics and clean-burning properties of gas are important considerations. Similarly, substitution of gas by oil as feedstock in the chemical industry alters the mix of chemical derivatives produced. Consequently, there are many applications for gas for which short-term switching to oil is either unsuitable or not physically possible.

To judge from aggregate statistics for 1985, 1986 and 1987, the period in which the industrial market's willingness to switch fuels was tested by the fall in oil prices, little switching actually took place. For Europe as a whole, industrial oil consumption in 1986 was only 14 thousand boe/d higher than it would have been if oil had simply maintained the same share of total industrial energy consumption as it held in 1985. In Table 3.4, industrial consumption of oil, gas and other energy is shown for Europe as a whole and for five countries which together account for over 90 per cent of the gas used by industry. Table 3.5 shows the increment or decrement in oil use (measured in mtoe

net heat value)[3] relative to what consumption would have been had oil maintained the same share of the industrial energy mix in each country as in the previous year.

The pattern of fuel switching shown in these tables is not consistent from one country to another. Belgium, Germany, the Netherlands and the UK each showed gains in oil use during 1986 and losses in 1987 which approximated the swings in gas consumption. However, in France and Italy, oil lost market share to gas and electricity in 1986. Nevertheless, it is worth noting that just as the UK accounted for most of the swing to oil in power generation, so it showed the largest swing of any country in the industrial sector. The quantity, however, was insignificant in world oil market terms, amounting to a swing of only 21 thousand b/d to oil in 1986 and 27 thousand b/d from oil in 1987.

There are two sources of movement in the pattern of industrial fuel consumption at the national level. One is the swing to or from oil in a particular industry. The other is the changing weight of that industry in the total of all industries. For Europe as a whole, some of the largest swings to oil in 1986 occurred in industries, such as iron or steel, which declined in weight relative to others. For example, total energy consumption by all industries fell by 2.3 per cent in 1986 versus 1985, but energy use by the iron and steel industry fell by 6.6 per cent. Thus, oil gained a larger share of a smaller market.

In some other industries, long-term trends dominated the pattern of fuel use. For example, in the process-oriented food industry oil showed substantial losses to gas in both 1986 and 1987 despite its fall in price. Furthermore, the industries in which oil lost market share gained in their share of the total energy consumed by all industries. In Tables 3.6 and 3.7, industrial fuel consumption and switching in Europe is shown on an industry-by-industry basis.

As the tables demonstrate, the clearest evidence of fuel switching between oil and gas in 1986 is displayed by the chemical industry where there is one-for-one substitution of oil for gas. But there, as elsewhere, the volumes involved were small. The additional consumption of oil attributable to fuel switching amounted to less than 20 thousand b/d compared to 1,060

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[3] 1 mtoe net heat value is equivalent to about 7.3 million barrels gross crude oil equivalent.

thousand boe/d total oil consumption by the chemical industry in 1986.

Assuming the losses of fuel market share by oil in the machinery, food, and paper industries for example are due to long-term structural or equipment changes, the swing to oil in the other principal energy consuming industries might arguably be called price-induced fuel switching. However, even allowing this, the volumes in aggregate for the other industries in which oil showed gains are insignificant – amounting to less than 50 thousand boe/d in 1986.

In conclusion, it appears that even at the price levels of 1986, the additional demand for oil that could be expected from short-term fuel switching in the industrial and power generation markets of Europe amounts to less than 300 thousand b/d.

Table 3.1: Power Generation in OECD Europe by Type of Fuel. Gigawatt Hours.

	Total Generation Public + Autoproducers			Oil-fired Generation Public + Autoproducers			Gas-Fired Generation Public + Autoproducers			All Other Generation Public + Autoproducers		
	1985	1986	1987	1985	1986	1987	1985	1986	1987	1985	1986	1987
OECD Europe	2001961	2044186	2123122	187537	174633	175499	112268	113979	122507	1702156	1755574	1825116
EEC 12	1572668	1612959	1659239	173350	159839	162581	104774	104886	112057	1294544	1348234	1384601
Belgium	57322	58676	63367	3742	2499	2238	2273	1051	2128	51307	55126	59001
France	344301	362784	378309	7062	5437	6180	3153	2850	2226	334086	354497	369903
Germany	408706	408266	418262	9415	12512	12374	24733	25350	28717	374558	370404	377171
Italy	185740	192330	201372	76174	77571	90048	24712	26871	31732	84854	87888	79592
Neths.	62947	67158	68419	3258	3456	3659	38213	41502	41292	21476	22200	23468
UK	297555	301590	302454	48307	31235	26153	2896	1743	1807	246352	268612	274494
Subtotal	1356571	1390804	1432183	147958	132710	140652	95980	99367	107902	1112633	1158727	1183629

Table 3.2: The Role of Oil and Gas in European Power Generation

	Oil & Gas % Share of Total Public + Production for Own Use			*Oil % Share of Oil & Gas Public + Production for Own Use*		
	1985	1986	1987	1985	1986	1987
OECD Europe	15.0	14.1	14.0	62.6	60.5	58.9
EEC 12	17.7	16.4	16.6	62.3	60.4	59.2
Belgium	10.5	6.1	6.9	62.2	70.4	51.3
France	3.0	2.3	2.2	69.1	65.6	73.5
Germany	8.4	9.3	9.8	27.6	33.0	30.1
Italy	54.3	54.3	60.5	75.5	74.3	73.9
Neths.	65.9	66.9	65.7	7.9	7.7	8.1
UK	17.2	10.9	9.2	94.3	94.7	93.5
Subtotal	18.0	16.7	17.4	60.7	57.2	56.6

Table 3.3: Fuel Switching to or from Oil and Gas-Fired Power Generation in OECD Europe. Gigawatt Hours.

	Fuel Switching Oil-Fired Generation Public & Production for Own Use			Fuel Switching Gas-Fired Generation Public & Production for Own Use			Fuel Switching Oil & Gas Generation Public & Production for Own Use			Fuel Switching All Other Generation Public & Production for Own Use		
	1985	1986	1987	1985	1986	1987	1985	1986	1987	1985	1986	1987
OECD Europe	NA	-16859	-5877	NA	-657	4127	NA	-17516	-1751	NA	17516	1751
EEC 12	NA	-17952	-1844	NA	-2572	4162	NA	-20524	2317	NA	20524	-2317
Belgium	NA	-1331	-461	NA	-1276	993	NA	-2607	532	NA	2607	-532
France	NA	-2004	510	NA	-472	-746	NA	-2476	-236	NA	2476	236
Germany	NA	3107	-444	NA	644	2746	NA	3751	2302	NA	-3751	-2302
Italy	NA	-1306	8830	NA	1282	3598	NA	-23	12428	NA	23	-12428
Neths.	NA	-20	138	NA	733	-989	NA	713	-851	NA	-713	851
UK	NA	-17727	-5171	NA	-1192	59	NA	-18919	-5112	NA	18919	5112
Subtotal	NA	-18982	3994	NA	965	5579	NA	-18017	9572	NA	18017	-9572

Table 3.4: Industrial Sector Energy Consumption in OECD Europe by Type of Fuel. Million Tonnes of Oil Equivalent.

	Total Energy Consumption (Includes electricity)			Oil Consumption			Gas Consumption			All Other Consumption		
	1985	1986	1987	1985	1986	1987	1985	1986	1987	1985	1986	1987
OECD Europe	311.56	304.41	311.96	106.47	104.73	103.86	65.24	64.01	69.68	139.85	135.67	138.42
EEC 12	261.43	255.04	260.63	90.32	89.56	88.56	62.46	61.06	66.49	108.65	104.42	105.58
Belgium	13.24	12.82	12.85	3.62	4.14	3.67	2.94	2.54	2.92	6.68	6.14	6.26
France	44.94	43.17	44.25	16.25	14.70	15.83	10.97	10.99	11.02	17.72	17.48	17.40
Germany	67.66	64.42	64.40	20.12	19.64	19.21	14.60	14.28	14.92	32.94	30.50	30.27
Italy	38.26	37.57	39.74	13.99	13.41	13.22	9.94	10.58	12.31	14.33	13.58	14.21
Neths.	19.79	20.04	21.34	6.61	7.47	7.82	8.56	8.04	8.83	4.62	4.53	4.69
UK	41.75	41.65	42.26	12.72	13.72	12.57	13.37	12.09	13.26	15.66	15.84	16.43
Subtotal	225.64	219.67	224.84	73.31	73.08	72.32	60.38	58.52	63.26	91.95	88.07	89.26

Table 3.5: Industrial Sector Fuel Switching to or from Oil and Gas by Country. Million Tonnes of Oil Equivalent Net Heat Value.

	Fuel Switching Oil Consumption			Fuel Switching Gas Consumption			Fuel Switching Oil & Gas Consumption			Fuel Switching All Other Consumption		
	1985	1986	1987	1985	1986	1987	1985	1986	1987	1985	1986	1987
OECD Europe	NA	0.70	-3.47	NA	0.27	4.08	NA	0.97	0.61	NA	-0.97	-0.61
EEC 12	NA	1.45	-2.96	NA	0.13	4.09	NA	1.57	1.13	NA	-1.57	-1.13
Belgium	NA	0.63	-0.48	NA	-0.31	0.37	NA	0.33	-0.11	NA	-0.33	0.11
France	NA	-0.91	0.76	NA	0.45	-0.24	NA	-0.46	0.52	NA	0.46	-0.52
Germany	NA	0.48	-0.42	NA	0.38	0.64	NA	0.86	0.22	NA	-0.86	-0.22
Italy	NA	-0.33	-0.96	NA	0.82	1.12	NA	0.49	0.15	NA	-0.49	-0.15
Neths.	NA	0.78	-0.13	NA	-0.63	0.27	NA	0.15	0.13	NA	-0.15	-0.13
UK	NA	1.03	-1.35	NA	-1.25	0.99	NA	-0.22	-0.36	NA	0.22	0.36
Subtotal	NA	1.71	-2.48	NA	-0.26	3.36	NA	1.45	0.88	NA	-1.45	-0.88

Table 3.6: Energy Consumption in OECD Europe by Type of Industry. Million Tonnes of Oil Equivalent.

OECD Europe	Total Energy Consumption (Includes electricity)			Oil Consumption			Gas Consumption			All Other Consumption		
	1985	1986	1987	1985	1986	1987	1985	1986	1987	1985	1986	1987
All Industries	311.56	304.41	311.96	106.47	104.73	103.86	65.24	64.01	69.68	139.85	135.67	138.42
Iron & Steel	61.97	57.90	56.90	4.34	4.77	4.15	7.26	7.07	7.25	50.37	46.06	45.50
Chemicals	100.21	97.92	103.14	53.06	52.82	55.37	26.14	24.57	26.63	21.01	20.53	21.14
Non-metallic Minerals	33.26	32.77	33.09	9.73	10.30	9.89	8.04	8.32	8.77	15.49	14.15	14.43
Machinery	16.71	16.90	16.79	5.09	4.76	4.56	5.46	5.72	5.65	6.16	6.42	6.58
Food & Tobacco	20.82	20.54	20.98	8.38	7.73	7.01	5.82	6.09	6.92	6.62	6.72	7.05
Paper, Pulp & Printing	21.38	21.55	22.17	4.90	4.65	4.08	3.58	3.81	4.30	12.90	13.09	13.79
Textile	9.14	8.70	8.82	3.63	3.49	3.22	1.90	1.79	2.01	3.61	3.42	3.59
Non-ferrous Metals	12.47	12.14	12.10	2.06	2.02	2.06	1.85	1.61	1.65	8.56	8.51	8.39
Subtotal	113.78	112.60	113.95	33.79	32.95	30.82	26.65	27.34	29.30	53.34	52.31	53.83

Table 3.7: Fuel Switching to or from Oil and Gas in OECD Europe by Type of Industry. Million Tonnes of Oil Equivalent.

OECD Europe	Fuel Switching Oil Consumption			Fuel Switching Gas Consumption			Fuel Switching Oil & Gas Consumption			Fuel Switching All Other Consumption		
	1985	1986	1987	1985	1986	1987	1985	1986	1987	1985	1986	1987
All Industries	NA	0.70	-3.47	NA	0.27	4.08	NA	0.97	0.61	NA	-0.97	-0.61
Iron & Steel	NA	0.72	-0.54	NA	0.29	0.30	NA	1.00	-0.24	NA	-1.00	0.24
Chemicals	NA	0.97	-0.27	NA	-0.97	0.75	NA	-0.00	0.48	NA	0.00	-0.48
Non-metallic Minerals	NA	0.71	-0.51	NA	0.40	0.37	NA	1.11	-0.14	NA	-1.11	0.14
Machinery	NA	-0.39	-0.17	NA	0.20	-0.03	NA	-0.19	-0.20	NA	0.19	0.20
Food & Tobacco	NA	-0.54	-0.89	NA	0.35	0.70	NA	-0.19	-0.19	NA	0.19	0.19
Paper, Pulp & Printing	NA	-0.29	-0.70	NA	0.20	0.38	NA	-0.09	-0.32	NA	0.09	0.32
Textile	NA	0.03	-0.32	NA	-0.02	0.20	NA	0.02	-0.12	NA	-0.02	0.12
Non-ferrous Metals	NA	0.01	0.05	NA	-0.19	0.05	NA	-0.18	0.09	NA	0.18	-0.09
Subtotal	NA	-0.49	-2.53	NA	0.97	1.63	NA	0.48	-0.89	NA	-0.48	0.89

FIGURE 3.1

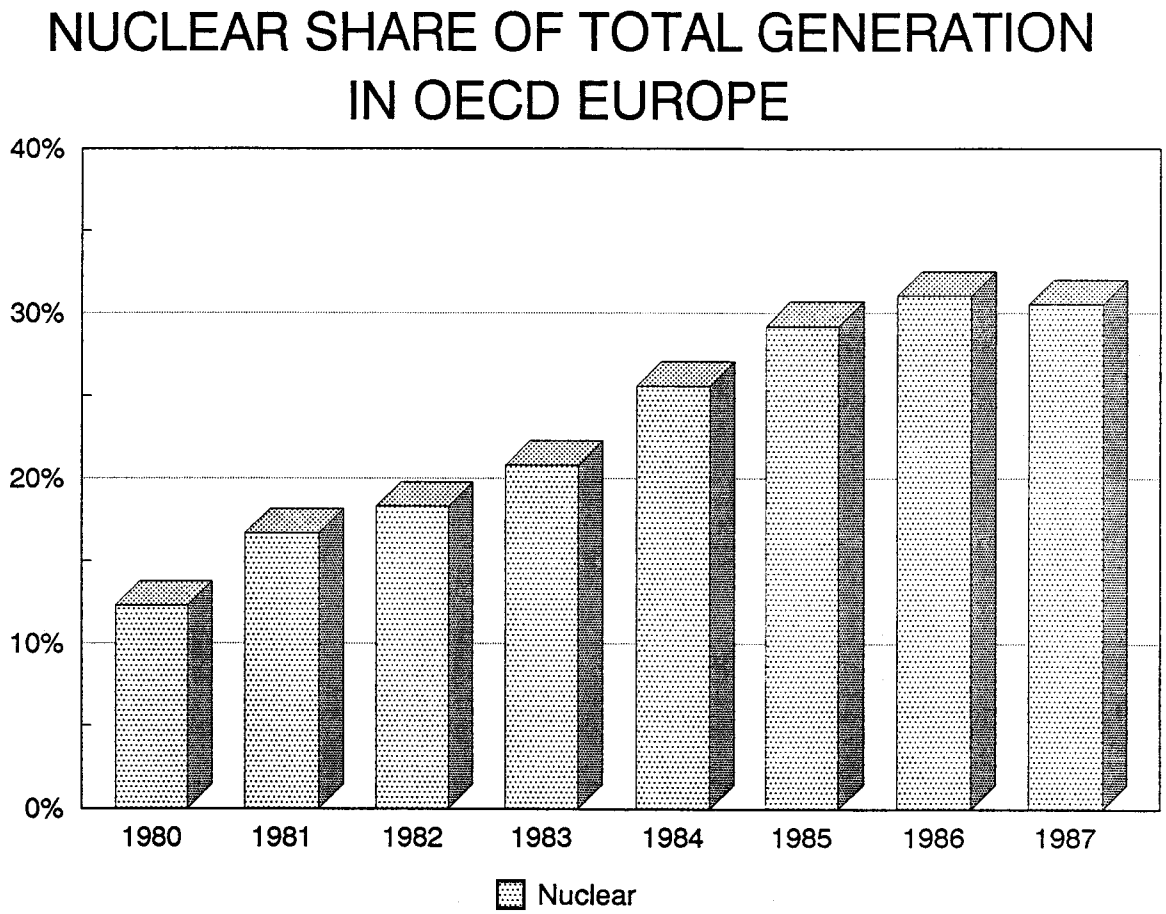

NUCLEAR SHARE OF TOTAL GENERATION
IN OECD EUROPE
40%
30%
20%
10%
0%
1980
1981
1982
1983
1984
1985
1986
1987
Nuclear

FIGURE 3.2

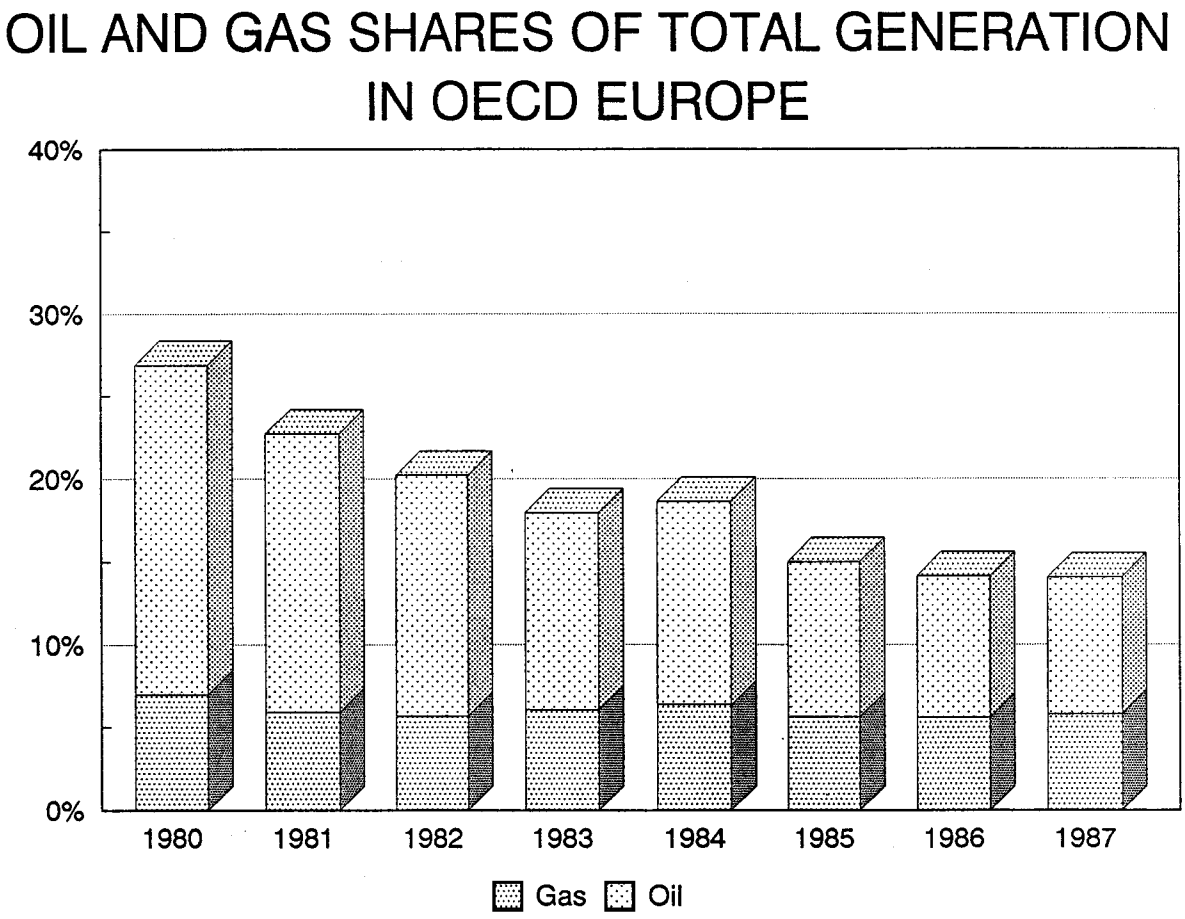

OIL AND GAS SHARES OF TOTAL GENERATION
IN OECD EUROPE
40%
30%
20%
10%
0%
1980
1981
1982
1983
1984
1985
1986
1987
Gas
Oil

FIGURE 3.3

PUBLIC POWER GENERATION FROM OIL & GAS IN THE EEC 12

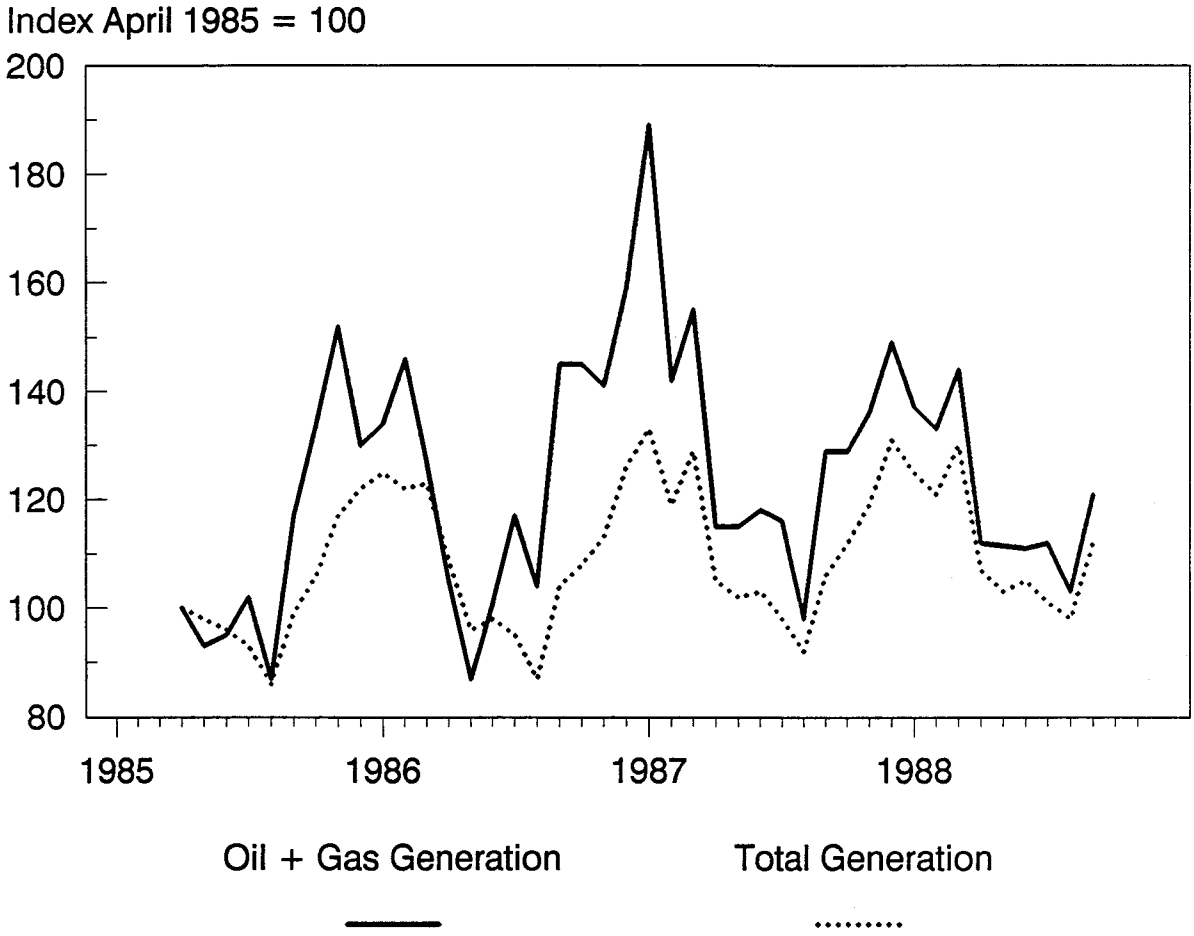


FIGURE 3.4

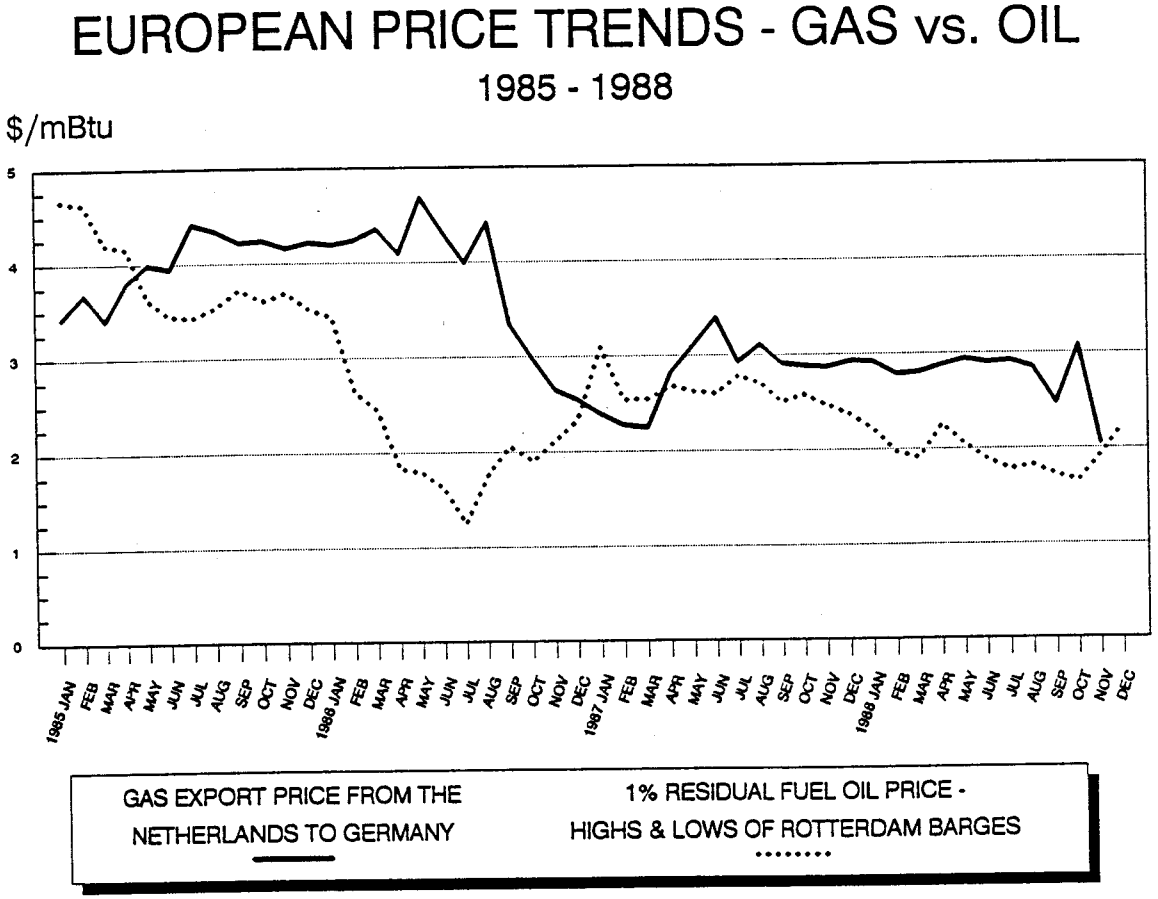
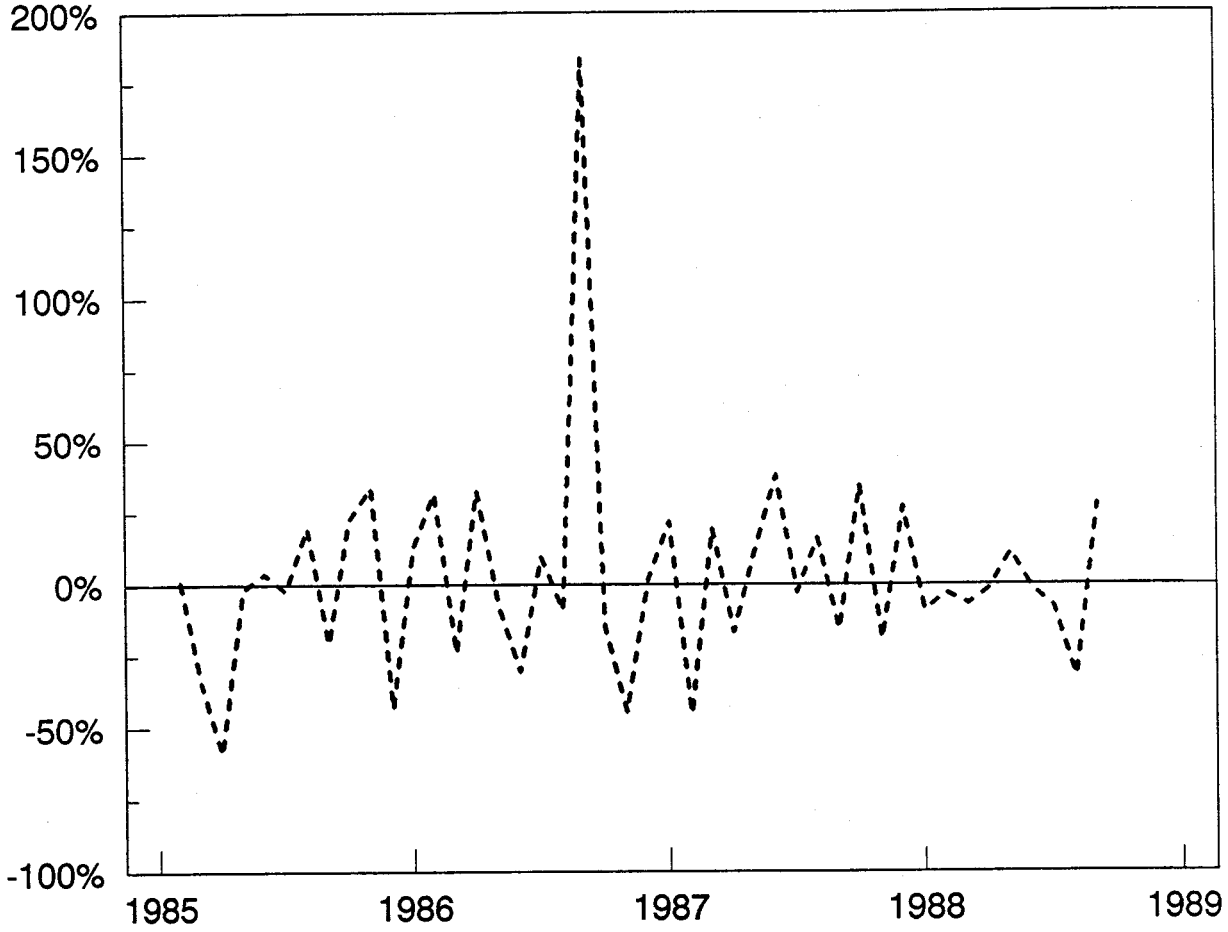

EUROPEAN PRICE TRENDS - GAS vs. OIL
1985 - 1988
$/mBtu
5
4
3
2
1
0
1985 JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
1986 JAN
1987 JAN
1988 JAN
GAS EXPORT PRICE FROM THE NETHERLANDS TO GERMANY
1% RESIDUAL FUEL OIL PRICE - HIGHS & LOWS OF ROTTERDAM BARGES

FIGURE 3.5

MONTHLY CHANGE IN OIL GENERATION MINUS CHANGE IN TOTAL GENERATION IN THE U.K.



Total Generation = Zero Oil-fired Generation

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4 JAPAN

4.1 Trends in Oil Consumption in Industry and Power Generation

Diversification of energy consumption away from oil has been a major element of Japanese energy policy since the first oil shock in 1973. The principal targets have been power generation and industrial uses. Because of the heavy influence of government policy, oil's market share in Japan is less susceptible to changes in oil pricing than it is throughout most of the OECD. Tables 4.1 and 4.2 show the trends in oil and other energy consumption in the power generation and industrial sectors since 1981. Gas is presently a specialized, and therefore, limited, fuel in industry. The minor shifts in oil market share during the pricing turmoil of the 1985-87 period are evident.

4.2 Oil Switching in the Context of the Gas Market

The Japanese gas market is based almost entirely on liquified natural gas imported by tanker. Before those shipments commenced in 1969, the gas industry was based on town gas manufactured in most of the larger cities throughout the country. The small indigenous production of natural gas – about 100 bcf, less than 1 per cent of primary energy in Japan – was commonly utilized as raw material in the manufacture of town gas. Following the introduction of LNG from the Cook Inlet of Alaska in 1969, imports grew rapidly with the completion of LNG projects from Abu Dhabi, Brunei, Kalimantan and Sumatra in Indonesia, and Malaysia. And in 1989 shipments began from the Northwest Shelf of Australia. By 1988 natural gas had risen to a 10 per cent share of Japanese primary energy and Japanese LNG imports of 30 million tonnes constituted more than 70 per cent of the world's LNG trade.

The overwhelming dependence of natural gas markets in Japan on capital-intensive, imported LNG projects has essentially institutionalized these markets, making them much less flexible to oil substitution than comparable gas markets in Europe or North America. Imports are based on long-term contracts, usually of twenty years duration, which contain take-or-pay clauses. They also utilize pricing formulas which are tied to oil price

levels. Thus in a period of oil price weakness such as that in 1986, the LNG projects suffer financial losses, but gas prices tend to track oil prices downward and the gas still flows. An additional factor which discourages the displacement of gas sales by oil is the systems approach to gas utilization which Japanese buyers have taken to alleviate the costs of imported LNG. The largest purchasers of LNG are the electric utilities. While initially the utilities used the gas in conventional boilers, more recently the trend is toward high-efficiency, combined cycle installations designed for gas-firing. And nearly all the receiving terminals make use of cold recovery, either for refrigeration of some sort or for cryogenic power systems. Thus converting to oil has economic penalties not usually associated with the more common dual-fired boilers.

Despite some manoeuvring on the part of Japanese buyers for greater take flexibility and for a reduction in the contractual relationship between gas and oil prices, there is little reason to believe that the basic philosophy of locking in markets for LNG projects will change. The insulation of existing gas markets from oil competition should therefore be expected to continue even without the restrictions imposed by government policy.

4.3 The Role of LNG in Gas Markets

Table 4.3 shows the breakdown of Japanese LNG and town gas markets for the fiscal year 1987 (ending 31 March, 1988). The import of LNG at 35.7 million tonnes represented 713 thousand boe/d. By far the largest portion (77 per cent) was purchased directly by electric utilities for power generation while most of the remainder went to the gas industry either for direct sendout as natural gas or for conversion to lower Btu town gas. The town gas markets are heavily concentrated in residential and commercial uses. Industrial use, while growing rapidly, still represents only about 50 thousand boe/d of sendout.

Buyers in Japan have contracted for more than 34 million tonnes of LNG. Total LNG volumes are purchased by ten different customers and received through thirteen different terminals scattered throughout the country. Table 4.4 summarizes the imports by source, indicating the purchasers, startup dates, contract term, and the destination terminals for each source.

The energy supply uncertainties following the 1986 oil price collapse led to a downgrading of expectations for LNG imports. The official Ministry of International Trade and

Industry (MITI) forecast of 38 million tonnes in total by the year 2000 still reflects this more pessimistic view. However, recent improvement in the economic climate, when combined with post-Chernobyl concern for nuclear power, has led to increased estimates once again. The Institute of Energy Economics has made a recent forecast of 48 million tonnes by 2000, which reflects the emerging optimism about LNG. It is not clear how much of this would be downgraded if low oil prices were to persist, since Japanese policy emphasizes diversification away from oil and most of LNG's prospective gains are at the expense of nuclear power.

4.4 LNG Receiving Terminals and Direct Utility Customers

Tokyo Electric joined with Tokyo Gas in contracting for the first imports out of Alaska, taking 75 per cent of the volumes. This established a precedent for electric utility direct purchases of LNG. Tokyo Electric alone accounts for about 25 per cent of all the LNG traded worldwide. Initially the utilities introduced LNG into existing or new thermal stations, where natural gas helped them meet air quality standards and was consistent with a national policy to diversify fuel utilization away from imported oil.

More recently they have been emphasizing combined cycle power generation where LPG or distillate, not residual fuel oil, is the alternative. The high potential cost of LNG as a fuel is in part mitigated by sulpher premiums on alternate fuel oil and, in the case of the combined cycle installations, the substantial increase in thermal efficiency. Three large new combined cycle plants to utilize LNG have recently been built at Niigata, Futtsu, and Yokkaichi.

The Tobata terminal on the island of Kyushu was built to service both the Kyushu Electric Power Co. and Nippon Steel. It thus represents the only direct import of LNG by an industrial customer. Part of the gas is utilized in Nippon's Yawata steel works – and thus may be more readily switchable to fuel oil than other gas uses. But much of the steel company's contract goes to a joint power station which may be much less flexible.

LNG is a liquid at -260°F and its vaporization creates an increase in volume similar to the boiling of water to make steam. Several different approaches to cryogenic power generation are possible and most Japanese LNG import terminals utilize one of these systems. In addition, other forms of cold recovery are common at some of these terminals. Applications currently

operating include air liquefaction and separation, solid carbon dioxide production, and food processing and freezing. A switch from gas to oil would require a shutdown of these ancillary facilities with some level of economic loss.

A listing of the thirteen Japanese LNG receiving terminals together with some of the systems applications which create a value premium for LNG over and above fuel oil substitution are shown as Table 4.5.

4.5 The Switchable Industrial Market

The industrial market for natural gas, though growing rapidly, is still very small. Aside from the direct LNG import by Nippon Steel in Kyushu, total industrial sales by the town gas suppliers (either as manufactured gas or directly as natural gas) constitutes less than 2 per cent of Japanese industrial energy consumption. The volume in total is less than 50 thousand boe/d.

Clearly much of the industrial load is for high-value process uses which are less affected by the high delivered prices of town gas than the oil-switchable boiler fuel loads. Much of this demand is likely to be quite insensitive to swings in competitive oil prices and thus not likely to be recaptured for oil, regardless of price.

4.6 Gas Price Contracting Patterns

Early LNG contracts were negotiated at prices which were significantly higher than oil parity. They were justified by the buyers' desire to develop early access to what was viewed as a premium, if high cost, energy source. The rapid increases in oil prices during the 1970s, and in particular those following the second oil shock, made gas prices seem cheap by comparison and set off a worldwide round of debate between gas exporters and importers as to how gas prices should relate to oil prices.

In 1980, a Japanese buyer accepted the concept of c.i.f. parity with Murban crude oil in its contract with Abu Dhabi, and that pattern has set the general standard for Japanese purchases since that time. Details affecting reference crude oils, definition of 'price', and timing for the adjustment mechanism to operate, differ among contracts. The actual tracking of oil prices by LNG prices is therefore not exact but the two price levels cannot depart from one another for very long. In years such as 1986 or 1988 when oil prices declined significantly, the tracking lag left gas temporarily overpriced, but the

relationship was soon restored. Figure 4.1 shows the relationship between oil and LNG prices since 1971.

There has been some manoeuvring by Japanese buyers to alter the c.i.f. formula, perhaps reducing it to 90 per cent of crude. But there seems to be little pressure from either buyers or sellers to break the direct relationship to oil prices. Thus it would seem very difficult for oil to recapture any significant share of gas markets by pricing alone, since gas would simply track oil's discounts and retain its markets.

Table 4.1: Japanese Energy Consumption for Power Generation. Thousand Barrels of Oil Equivalent per Day.

	1981	*1982*	*1983*	*1984*	*1985*	*1986*	*1987*
Oil	1,109	1,017	994	994	814	798	767
Gas	324	334	352	490	536	535	541
Coal	270	269	331	366	418	417	428
Nuclear	430	502	560	658	782	752	839
Hydro/Other	448	418	438	383	438	391	367
Total	2,581	2,541	2,677	2,891	2,988	2,893	2,942

Source: OECD statistics

Table 4.2: Japanese Energy Consumption for Industry. Thousand Barrels of Oil Equivalent per Day.

	1981	*1982*	*1983*	*1984*	*1985*	*1986*	*1987*
Oil	1,074	965	992	1,033	996	1,008	1,028
Gas	57	57	57	64	69	70	73
Coal	720	705	652	719	710	661	683
Electricity	551	540	566	596	608	601	632
Total	2,402	2,266	2,268	2,412	2,384	2,340	2,415

Source: OECD statistics

Table 4.3: Japanese LNG and Town Gas Markets. 1987.

	Thousand Barrels of Oil Equivalent per Day	*Million Tonnes of Oil Equivalent*
LNG Imports		
Electricity	549.7	27.5
Steel Industry	1.5	0.1
Gas Industry	161.9	8.1
Total	713.1	35.7
Town Gas Feedstock		
LNG	162.9	8.1
Indigenous Gas	16.2	0.8
LPG	42.1	2.1
Naphtha	7.6	0.4
Coal	18.2	0.9
Other	7.2	0.4
Total	254.1	12.7
Japanese Town Gas		
Residential	133.1	6.7
Commercial	41.7	2.1
Industrial	49.8	2.5
Other	16.1	0.8
Total	240.7	12.0

Source: Ministry of International Trade and Industry

Table 4.4: Japanese LNG Imports by Source.

Gas Source	*Startup Date*	*Gas Purchaser*	*Receiving Terminal*	*Contract Million Tonnes per Year*	*Startup Date*	*Term Years*
Alaska (Cook Inlet)	1969	Tokyo Gas	Negishi	0.27		
		Tokyo Electric	"	0.82		
Subtotal Alaska				1.09	1969	20
Abu Dhabi	1977	Tokyo Electric	Sodegaura	2.06	1977	20
Brunei	1972	Tokyo Gas	Sodegaura	1.06		
		Tokyo Electric	Negishi	3.45		
		Osaka Gas	Senboku I	0.63		
Subtotal Brunei				5.14	1972	20
Indonesia I	1977	Osaka Gas	Senboku II	1.30		
		Kansai Electric (Himeji)	(Senboku II)	2.40		
		Chubu Electric	Chita	1.70		
		Kyushu Electric	Tobata	1.50		
		Nippon Steel	"	0.60		
Subtotal Indonesia I				7.50	1977	23
Indonesia II	1983	Osaka Gas	Senboku II	0.40		
		Toho Gas	Chita	0.50		
		Chubu Electric	"	1.50		
		Kansai Electric	Himeji	0.80		
Subtotal Indonesia II				3.20	1983	20
Indonesia III	1984	Tohuku Electric	Nihonkai-Niigata	2.90		
		Tokyo Electric	Sodegaura	0.40		
Subtotal Indonesia III				3.30	1984	20
Malaysia	1983	Tokyo Gas	Sodegaura	2.00		
		Tokyo Electric	(Ohgishima) (Futtsu)	4.00		
Subtotal Malaysia				6.00	1983	20
Total Operating				28.29		

Table 4.4: Continued

LNG Imports by Source.

Gas Source	*Startup Date*	*Gas Purchaser*	*Receiving Terminal*	*Contract Million Tonnes per Year*	*Startup Date*	*Term Years*
Australia	(1989)	Tokyo Gas	Sodegaura	0.58	1989 Est	19
		Tokyo Electric	Futtsu	0.90		
		(Osaka Gas)	Senboku II	0.58		
		(Toho Gas)		0.18		
		Chubu Electric	Yokkaichi	0.90		
		Kansai Electric	Himeji	0.90		
		Chugoku Electric	Yanai	0.90		
		Kyushu Electric	Oita	0.90		
Subtotal Australia				5.84		
Total Planned and Operating				34.13		

LNG BUYERS

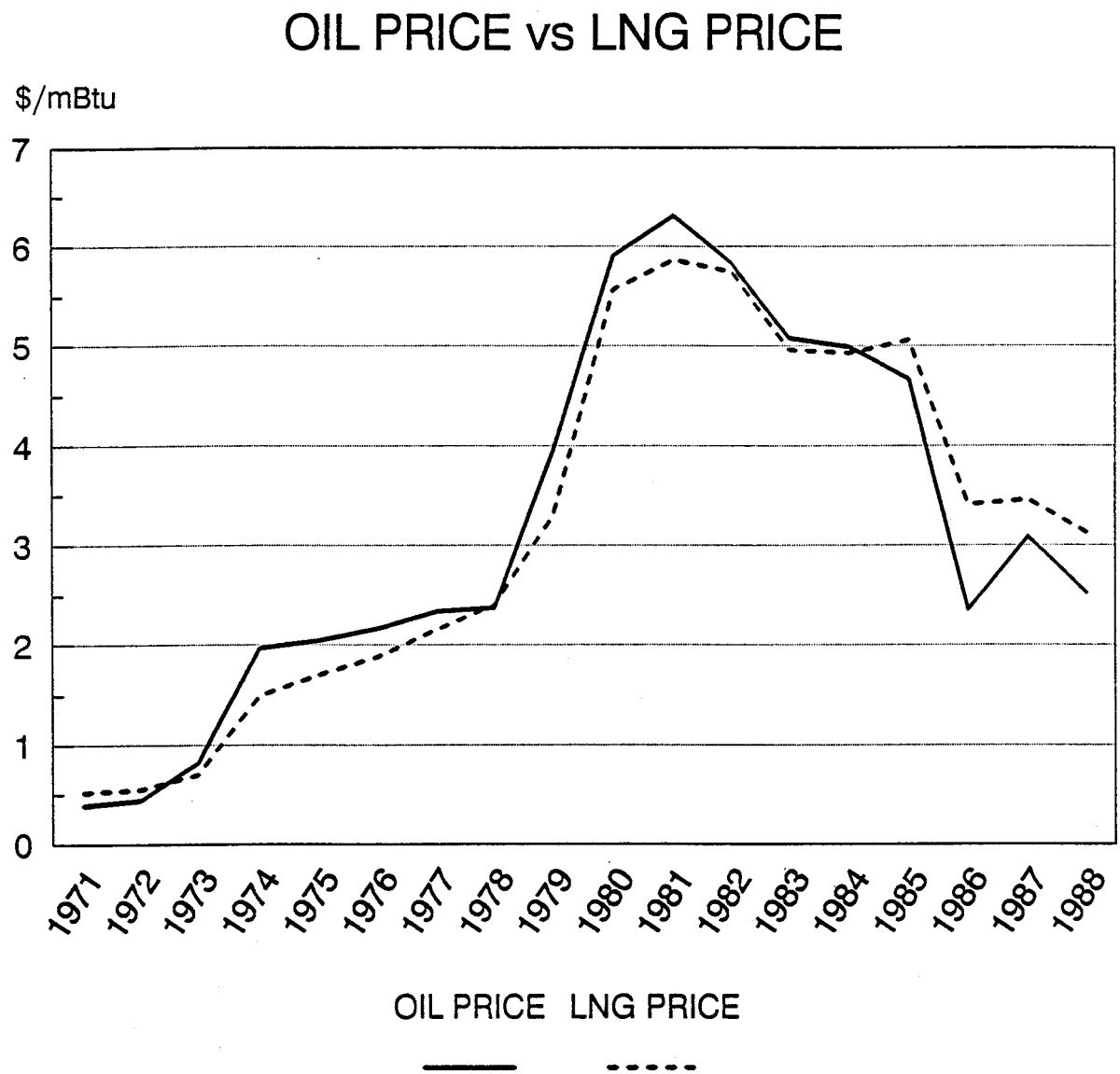
Companies	
Tokyo Gas	3.91
Osaka Gas	2.91
Toho Gas	0.68
Total Gas	7.50
Tokyo Electric	11.63
Kansai Electric	4.10
Chubu Electric	4.10
Tohuku Electric	2.90
Kyushu Electric	2.4
Chugoku Electric	0.90
Total Electric	26.03
Nippon Steel	0.6
Total Steel	0.6

Table 4.5: Japanese LNG Import Terminals.

Terminal	Cryogenic Power Cold Recovery	Purchaser	LNG Source	Gas (Million Tonnes Per Year)	Electricity (Million Tonnes Per Year)	Steel (Million Tonnes Per Year)	Notes
Tokyo Area							
Negishi, Kanagawa	CP,CR	Tokyo Gas	Alaska, Cook Inlet		0.27		
		Tokyo Electric	"			0.82	
		"	Brunei			3.45	
Sodegaura, Chiba	CR	Tokyo Gas	"		1.06		
		"	Malaysia		2.00		
		"	Australia (1989)		0.58		
		Tokyo Electric	Abu Dhabi			2.06	
		"	Indonesia III			0.40	
Higashi-Ohgishima, Kanagawa	CP	"	Malaysia)			4.00	
Futtsu, Chiba	CP	"	Malaysia)				Combined Cycle Station
		"	Australia (1989)			0.90	
Nagoya Area							
Chita, Aichi	CP,CR	Toho Gas	Indonesia II		0.50		
		Chubu Electric	Indonesia I			1.70	
		"	Indonesia II			1.50	
Yokkaichi, Mie	*	"	Australia (1989)				Combined Cycle Station
Osaka Area							
Senboku I, Osaka	CR	Osaka Gas	Brunei		0.63		
Senboku II, Osaka (Includes Himeji)	CP,CR	"	Indonesia I		1.30		
		"	Indonesia II		0.40		
		"	Australia (1989)		0.58		
		Toho Gas	"		0.18		
		Kansai Electric	Indonesia I			2.40	
Himeji, Hyogo	CP,CR	Osaka Gas	(See Senboku II)				
		Kansai Electric	Indonesia II			0.80	
		"	Australia (1989)			0.90	
Kyushy Area							
Tobata, Fukuoka	CP	Nippon Steel	Indonesia I			0.60	
		Kyushu Electric	"		1.50		Kokura, Tobata Joint Stations
Oita, Oita	*	"	Australia (1989)		0.90		
Other							
Nihonkai-Niigata, Niigata	CP,CR	Tohuku Electric	Indonesia III		2.90		Combined Cycle Station
Yanai, Yamaguchi	*	Chugoku Electric	Australia (1989)		0.90		
				7.50	26.03	0.60	

* New terminals, configuration not known

FIGURE 4.1


OIL PRICE vs LNG PRICE
$/mBtu
7
6
5
4
3
2
1
0
1971
1972
1973
1974
1975
1976
1977
1978
1979
1980
1981
1982
1983
1984
1985
1986
1987
1988
OIL PRICE
LNG PRICE

5 THE IMPLICATIONS OF THE 1986 OIL PRICE COLLAPSE FOR FUTURE OIL DEMAND

In the United States, Europe and Japan the response of oil markets to the 1986 oil price collapse was very much the same. The increase in oil's share of industrial and power generation markets was both limited (where there was any gain at all) and temporary in nature.

There were two types of price signals. The initial oil price decline in February and March of 1986 was both deep and rapid. It was followed by a mid-summer aftershock that established a bottom below $10 per barrel. This precipitous decline provided a price signal to the market might have been expected to set in motion extensive short-term switching to oil from alternate fuels. The fact that it did not do so suggests that either the effective technical capability to substitute was comparatively limited, or that alternate fuels did not find it difficult to match the short-term price decline.

The second price signal was one with longer-term implications for oil's market share. By early 1987 there was a substantial crude oil price recovery from the 1986 midsummer bottom, but it retraced less than half of the 1986 decline. The recovery lessened the short-term pressure to switch to oil. But in its wake it left a much lower pricing environment for justifying new investment in alternate energy sources and a perception of increased project risk from volatile oil prices. It is much more difficult to measure the market share effects of this second set of price signals, since they will presumably evolve slowly over a long period of time. The only significant market share improvement for oil is likely to come from these signals, however.

In the short-term, oil has little ability to displace gas or coal in residential or commercial uses nor can it compete in nuclear or hydro-generating stations. One would expect, therefore, that oil's greatest market penetration would occur against gas or coal in industry and power generation. The technical capability to switch to oil in this market is concentrated in those dual-fired boilers that can substitute oil

for gas or coal when oil prices are low. Furthermore, since gas-fired units are likely to require substantially lower capital investment than coal-fired units, they are often justified economically with much higher fuel costs than their coal counterparts. Of all the energy sources, gas would appear, therefore, to be the most vulnerable to oil price competition.

The very limited displacement of gas by oil during the 1986 oil price collapse failed to support this expectation of competitive vulnerability. That oil could not capture markets from gas appears to reflect the fact that the short-run marginal costs of supplying gas are often very low once the high fixed costs of transporting, delivering and storing the fuel have been justified. In many cases the investment in pipelines or LNG facilities has been possible only on the basis of firm contracts that restrict the buyers' ability to switch because of such long-term contract provisions as minimum offtake agreements or take-or-pay clauses. In such cases natural gas may be all but immune from oil price competition. This was particularly true in Japan, where nearly all of the natural gas is supplied on long-term LNG contracts from Pacific Basin supplies.

Even in the United States, where natural gas most nearly approaches commodity status, oil failed to penetrate gas markets significantly despite the oil price drop. In retrospect, gas producers and pipelines chose to meet the price competition from oil rather than lose market share. This was evidence that the short-run marginal costs of supplying gas were low and still provided attractive positive cash flow even at low prices. Gas prices and supplier profitability dropped but gas did not lose a significant share of the market.

The principal gains that oil will make against gas are thus likely to be concentrated in the long term. The need to justify the heavy capital expenditure required for new pipeline or LNG facilities or even to sustain gas exploration and field development makes these investments inherently price-sensitive. Thus oil could be expected to gain against gas over a longer period of time as low oil prices inhibit these gas investments. The 1986 oil price collapse was able to demonstrate that gas and coal were largely invulnerable to severe oil price competition in the short run. It did not provide a long enough price history to measure the long-run effects of suppressing investments in alternative fuels.

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