ENERGY FORUM
JAMES A. BAKER III
INSTITUTE FOR PUBLIC POLICY
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Natural Gas in North America: Markets and Security

International Influences on the Link between U.S. Crude Oil and Natural Gas Prices

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ABOUT THE POLICY REPORT

NATURAL GAS IN NORTH AMERICA: MARKETS AND SECURITY

Predicted shortages in U.S. natural gas markets have prompted concern about the future of U.S. supply sources, both domestically and from abroad. The United States has a premier energy resource base, but it is a mature province that has reached peak production in many traditional producing regions. In recent years, environmental and land-use considerations have prompted the United States to remove significant acreage that was once available for exploration and energy development. Twenty years ago, nearly 75 percent of federal lands were available for private lease to oil and gas exploration companies. Since then, that share has fallen to 17 percent. At the same time, U.S. demand for natural gas is expected to grow close to 2.0 percent per year over the next two decades. With growth in domestic supplies of natural gas production in the lower 48 states expected to be constrained in the coming years, U.S. natural gas imports are expected to rise significantly in the next two decades, raising concerns about supply security and prompting questions about what is appropriate national natural gas policy.

The future development of the North American natural gas market will be highly influenced by U.S. policy choices and changes in international supply alternatives.

The Baker Institute Policy Report on *Natural Gas in North America: Markets and Security* brings together two research projects undertaken by the Baker Institute’s Energy Forum. The first study focuses on the future development of the North American natural gas market and the factors that will influence supply security and pricing. This study considers, in particular, how access to domestic resources and the growth of international trade in liquefied natural gas will impact U.S. energy security. The second study examines the price relationship between oil and natural gas, with special attention given to natural gas demand in the industrial and power generation sectors – sectors in which natural gas can be displaced by competition from other fuels. This policy report is designed to help both market participants and policymakers understand the risks associated with various policy choices and market scenarios.

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ABOUT THE ENERGY FORUM AT THE JAMES A. BAKER III INSTITUTE FOR PUBLIC POLICY

The **Baker Institute Energy Forum** is a multifaceted center that promotes original, forward-looking discussion and research on the energy-related challenges facing our society in the 21st century. The mission of the Energy Forum is to promote the development of informed and realistic public policy choices in the energy area by educating policy makers and the public about important trends—both regional and global—that shape the nature of global energy markets and influence the quantity and security of vital supplies needed to fuel world economic growth and prosperity.

The forum is one of several major foreign policy programs at the James A. Baker III Institute for Public Policy at Rice University. The mission of the Baker Institute is to help bridge the gap between the theory and practice of public policy by drawing together experts from academia, government, the media, business, and nongovernmental organizations. By involving both policymakers and scholars, the institute seeks to improve the debate on selected public policy issues and make a difference in the formulation, implementation, and evaluation of public policy.

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I. Introduction

Our analysis of natural gas and crude oil prices in the United States revealed that there is a stable *long run* relationship between crude oil and natural gas prices over time but that this relationship is indirect, acting through competition between natural gas and *refined petroleum products*. Although *short run* forces can drive crude oil and natural gas prices away from their long run equilibrium relationship, both market arbitrage, which acts in the short run, and changes in investment, which acts in the long run, tend to reestablish the long run equilibrium relationship. In addition, our results showed that while crude oil prices – West Texas Intermediate (WTI) crude to be specific – influence movements of natural gas and petroleum product prices, changes in U.S. natural gas prices have little or no influence on WTI.

Our investigation revealed that fuel competition in electricity generation has the strongest influence in establishing the link between the U.S. crude oil and natural gas prices. Two lines of evidence supported this conclusion. First, we found that changes in the heat rate of natural gas-fired generation capacity over the past 15 years provides a sound explanation for an apparent evolution in the long run equilibrium relationship between WTI and U.S. natural gas prices. Second, we found the strongest evidence for natural gas-oil fuel substitution in the electricity sector and, to a lesser extent, in the cogeneration of electricity in the industrial sector. An explanation for these observations is that even if there are few generating plants that can physically engage in fuel switching onsite, the types of fuel can nevertheless compete through dispatch decisions based on relative costs of generation across a region with multiple plants with different fuel sources. Furthermore, analysis focusing specifically on plants with dual-fuel capability reveals a reasonable amount of plant-level fuel switching, a result that contradicts some anecdotal evidence. One reason for this, perhaps, is that a lot of the existing dual-fired capacity is in the form of small-scale, cogeneration facilities rather than the kind of large-scale power generation that was more prominent in the 1970s and 1980s.

One of the issues we address in this paper is whether the price relationship between crude oil and natural gas prices found in the United States translates to other regions, especially Japan and the European Union. If oil products and natural gas are effective substitutes in electricity generation in these other markets, and generation technologies are similar, the pricing relationships we have found in the United States should be reinforced in global markets. However, if interfuel substitution in overseas markets reflects factors that differ from those that dominate in the United States, the long run relationship between crude oil and natural gas prices could also differ across countries. In turn, this would provide arbitrage opportunities between regional markets that could be exploited via increased trade in liquefied natural gas (LNG) and may cause the price relativity in the United States to evolve over time. Otherwise stated, as natural gas is increasingly traded internationally, market realities in other regions could cause the existing price relationship between crude oil and natural gas prices in the United States to shift.

We also address the potential for factors other than demand-side substitution, such as changing supply economics, gas sales contracting practices and geopolitical trends, to influence the relationship between crude oil and natural gas prices. One supply-side mechanism reflects oil field operating decisions. The value of natural gas relative to crude oil can influence the amount of natural gas that is ultimately supplied to international markets and how much is used for enhanced recovery and/or lease operations, particularly if the natural gas is associated. These production decisions, however, generally require some capital outlay and therefore influence price adjustment only over a longer period of time. The wider adoption of gas-to-liquids (GTL) production is another growing supply-side factor that may increasingly influence the price link between crude oil and natural gas. GTL output is forecast to grow from 165,000 barrels per day (b/d) currently to more than 1 million b/d in the coming decade, mainly from proposed projects in Qatar and other low-cost gas production areas. Some estimates predict GTL could reach 2 million b/d by 2025, depending on market trends.

Long-term contracts between buyers and sellers of LNG that explicitly link the price of LNG to the price of crude oil are another potential international influence on the relationship between crude oil and natural gas prices. It is reasonable to assume that the nature of these links, and how they may evolve over time, could either alter or reinforce the relationship between crude oil and natural gas prices that is observed in the United

States. In particular, a long-term contract establishes a short-term value of crude oil and natural gas for parties to the contract. However, it is unlikely that contract terms which deviate from other market forces that determine the relative values of crude oil and natural gas will be able to persist. In fact, perceptions of the relative values of crude oil and natural gas drive contract negotiations. Furthermore, if an existing contract is “out-of-the-money,” it may be possible to utilize futures markets in liquid gas-on-gas trading environments and/or diversion strategies to offset any losses, which would effectively minimize the influence of the “out-of-the-money” contract on the oil-natural gas pricing relationship by shifting the arbitrage process into the more freely traded spot or financial markets for the commodities.

None of the factors that influence the relationship between crude oil and natural gas is independent of the others. In fact, they can serve to reinforce or offset each other. Thus, while it is important to think of these factors independently to understand their influence, one must also recognize that they act in concert to determine market adjustments at the aggregate level. Nevertheless, any one factor can have a more pronounced influence than the others. Econometric analysis reveals strong evidence that fuel switching in the power generation sector has exerted a substantial influence over the long run crude oil-natural gas price relationship. In the future, however, if fuel switching capabilities become diminished, it is possible that one of these other factors could establish a new long run relationship between oil and gas.

We begin this paper with a discussion of the long run relationship between natural gas and crude oil in order to establish why we believe the prices will tend to some equilibrium, recognizing that the equilibrium could evolve due to technological developments. We then discuss some of the market fundamentals that influence the dynamic price adjustment process from the short run to the long run. Finally, we address some of the political factors that could alter the relative values of crude oil and natural gas, thereby reshaping the long run relationship between the fuels.

II. The dynamic relationship between oil and gas

Hartley, Medlock and Rosthal (2007) utilize an error correction approach to characterize the aggregate relationship between U.S. crude oil and natural gas prices which allows for short run departures from (and dynamic adjustment toward) a stable long run equilibrium. A distinction between the short and long run is important to understanding the dynamic relationship between crude oil and natural gas. Specifically, atypical occurrences in the market that are short run in nature, such as, a warmer than normal winter and a resulting storage surplus, tend to drive natural gas and crude oil prices away from their long run equilibrium. On the other hand, arbitrage and investment tend to push them back.

To illustrate this, we can consider three possibilities regarding the prices of natural gas and crude oil: (1) oil and natural gas are in their long run equilibrium; (2) natural gas is *above* its long run equilibrium with oil; and (3) natural gas is *below* its long run equilibrium with oil. The first case requires little discussion since no dynamic adjustment is necessary. Cases (2) and (3) are of primary interest here.

In case (2), in which natural gas prices exceed their long run equilibrium value for a given crude oil price, arbitrage and/or investment will correct the imbalance. To fully understand the mechanism, consider two possible subcases: (2a) natural gas is above its long run equilibrium with crude oil in the United States; and (2b) natural gas is above its long run equilibrium with crude oil only *outside* of the United States. To keep the analysis simple, assume natural gas prices in markets outside the one being analyzed remain at their long run equilibrium with crude oil prices. We will relax this constraint below.

Price differentials will encourage various types of arbitrage to take advantage of the situation. For example, in case (2a) with relatively high U.S. natural gas prices, LNG cargoes will be diverted from other markets to the United States in order to capture rent. Within the United States, fuel switching to oil from natural gas will decrease demand for natural gas, while short run deliverability at the wellhead could increase slightly. All of these responses will place downward pressure on natural gas prices in the United States. In the case of LNG cargoes, if there is insufficient import capacity, then a bottleneck will prevent the prices from being fully arbitraged. This will, especially if persistent, encourage investment in import capacity to the point that the long run equilibrium is reached. Persistent high prices will also encourage development of frontier U.S. natural gas supplies and stimulate investment in generation capacity that is not gas-fired. These factors will tend to have a longer-term dampening effect on U.S. natural gas prices.

In case (2b) where foreign gas prices are relatively high, LNG supplies otherwise destined for the United States will tend to flow toward the markets where natural gas prices are high. In addition, the higher natural gas price should discourage demand in those markets, perhaps through fuel switching. Higher supply and reduced demand should then push international natural gas prices lower (more in line with U.S. prices). In addition, if infrastructure or policy prevents the prices from being fully arbitraged, investments will occur until prices are once again in their long run equilibrium.

If we relax the constraint that prices in other markets are not affected, we see that in both cases, arbitrage through diversion of LNG cargoes could result in gas prices everywhere being above their long run equilibrium relationship with oil. Therefore, short run adjustment through fuel switching will occur everywhere, associated with, possibly to a limited extent, a ramping up of supply at the wellhead. If there is an inadequate ability to switch, through either a lack of capacity or environmental constraints, investments in the supply of natural gas will be encouraged as will investments in alternative fuel sources in the power generation sector. This will then eventually place downward pressure on natural gas prices relative to crude oil through increased supply and reduced demand growth.

Arbitrage and investment, although they both play a role in relative price movements, have different effects. Arbitrage tends to facilitate fairly rapid adjustment back to long run equilibrium by easing demand pressures or supply constraints fairly quickly. Investment, however, acts more slowly. With extended infrastructure lead times in developing supply and any necessary transportation and delivery infrastructure, adjustment to long run equilibrium could take in excess of two to three years. Nevertheless, both tend to push crude oil and natural gas into long run equilibrium.

In case (3), natural gas prices are assumed to be below their long run equilibrium with crude oil prices. Again, consider two different scenarios under which this may occur: (3a) natural gas is below its long run equilibrium with crude oil in the United States only; and (3b) natural gas is below its long run equilibrium with crude oil only in markets *outside* the United States. To keep the analysis simple, assume natural gas prices in markets outside the one being analyzed remain at their long run equilibrium with crude oil prices. We will relax this constraint below.

In case (3a), an increase in natural gas demand in the U.S. power generation sector would be encouraged through fuel switching. This would, in turn, place upward pressure on natural gas prices, helping to bring natural gas back into its long run equilibrium with crude oil. On the supply-side, LNG cargoes would seek the higher-priced markets outside of the United States, and domestic production could be curtailed. This would reduce supply in the U.S. market and put upward pressure on the natural gas price. If none of these factors was sufficient to return natural gas prices to their long run equilibrium with crude oil prices, then investment behavior would adjust. Specifically, investment in gas-fired generation capacity would be encouraged given the relatively low cost of fuel, and investments in new natural gas supplies and/or LNG regasification capacity could be delayed. These factors would tighten the U.S. natural gas market over a longer time frame, eventually raising prices.

In case (3b), if natural gas is below its long run equilibrium outside the United States, LNG cargoes would be diverted to U.S. markets, and foreign demand would be encouraged through fuel switching away from oil to natural gas. Again, if these factors were not sufficient to return natural gas prices to their long run equilibrium relationship, the appropriate investments would be encouraged.

If we relax the constraint that prices in other markets are not affected, we see that in both cases there will tend to be downward pressure on prices. As a result, there is an opportunity for natural gas storage in the United States to play a role in arbitraging price variations over time. If, for example, natural gas prices in the summer decline in Europe, perhaps from weak demand due to mild weather, LNG cargoes would be diverted to U.S. markets and tend to lower prices in the United States. This would encourage an increase in natural gas demand through fuel switching in the United States (as in case (3a)), but it might also encourage an increase in natural gas injections into storage as traders seek to capture higher rents by injecting immediate supplies into storage and selling them forward on futures markets to lock in higher prices. This would then mean that when the winter heating season arrives, increased demand in the United States could be met by natural gas withdrawals from storage, leaving LNG cargoes to be delivered to Europe. Since both the United States and Europe share seasons, this would mean that the United States serves as a storage hub of sorts for the entire Atlantic Basin.[1] Notice that this behavior results in a dampening of natural gas prices in both the United States and Europe when demand falls in Europe, but the ability to store natural gas and divert LNG means that any weather-driven departure of the natural gas price from its long run equilibrium with crude oil price will be short-lived. If, in this example, demand for natural gas permanently fell in Europe, then future investments in the development of supplies would adjust accordingly since the returns to such endeavors would likely be lower.

In both cases (2) and (3), notice that the adjustment back to long run equilibrium occurs as result of fuel switching, changes in supply and, potentially, adjustments in investment behavior. Moreover, storage markets could provide a mechanism through which prices could adjust to seasonal departures from long run equilibrium.

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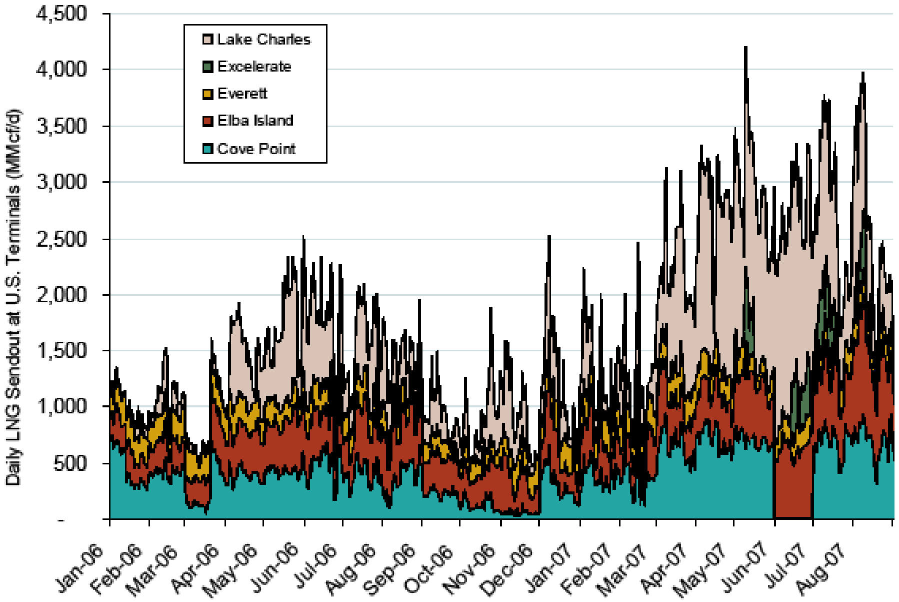
[1] This, of course, recognizes that geology in the United States near major market centers is more conducive to storage of natural gas.

Figure 1: Daily LNG deliveries to the United States (Jan. 2006 – Aug. 2007)



Source: Derived from *Bentek* data. Excludes Everett LNG delivered via truck and consumed by the Mystic plant. *Updated September 7, 2007*

Source: FERC

Recent history provides evidence of the types of market behavior just discussed. The winter of 2005-06 was especially cold in Europe and rather mild in the United States. As a result, the EU was the preferred market for LNG deliveries as natural gas prices rose substantially. Beginning in the late spring, however, mild weather in Europe resulted in diversion of LNG cargoes to the United States (see Figure 1). This contributed to a rise in natural gas inventories in the United States to record-high levels, which in turn caused the natural gas price in the United States to fall to the point where it was below the price of residual fuel oil. Even so, prices in the United States were generally above those in Europe, which spurred the diversion of LNG cargoes from Europe to the United States. This trend was exacerbated by weather driven demands. Warmer than normal weather in the United States in July and August triggered an increase in electricity demand for air conditioning, giving generators and system operators an opportunity to dispatch either natural gas or fuel oil fired capacity to generate electricity to meet the increased load. The relatively low price of natural gas contributed to higher than normal demand in the electricity sector, as the U.S. market underwent two weeks of withdrawals from storage as natural gas demand increased. This had never before occurred in the summer, which is traditionally considered a low-demand period when gas is injected into storage. The rapid increase in natural gas demand was facilitated by relatively inexpensive natural gas prices, which were, as stated above, discounted relative to fuel oil. During the winter of 2006-07, the United States still enjoyed a storage surplus, and winter LNG cargoes flowed toward Europe. In 2007, growth in global LNG supply has tended to amplify the seasonal arbitrage that has occurred across the Atlantic Basin. Storage capacity and demand in the U.S. market is sufficient to keep prices from dropping precipitously even when cargoes are diverted from Europe to the United States. Thus, the scenario described in case (3) is in fact being played out.

III. Demand-side influences

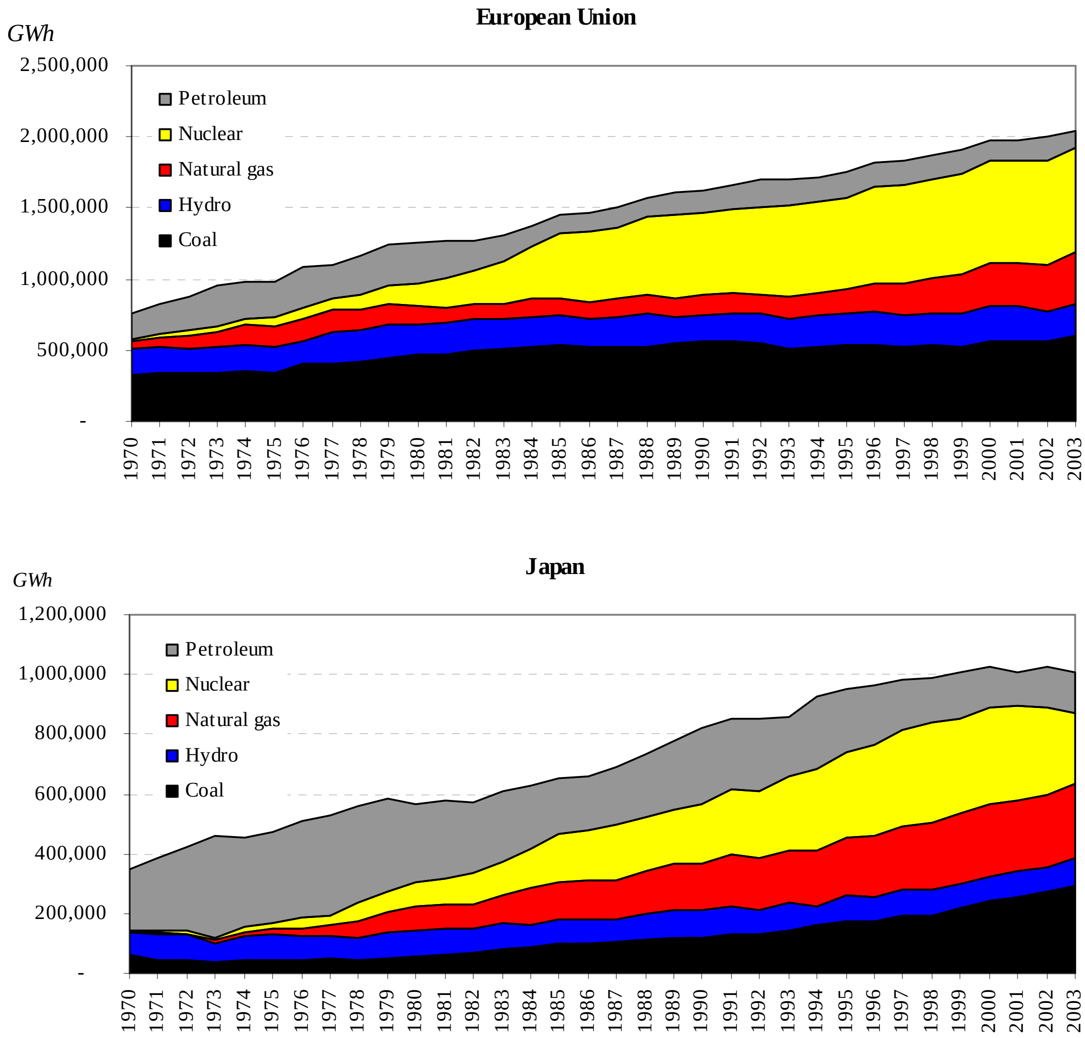
In discussing the demand-side factors overseas, we focus on impact of fuel switching in Japan and the countries of the EU. Like the United States, these are large, well-established markets for natural gas with a technological consumption base in a wide range of sectors that could be conducive to significant interfuel substitution. Other countries, such as Russia, China and India, may also exert a significant influence on the price relationship through interfuel competition, particularly in the future. Since their consumption patterns are changing so rapidly, it is difficult to make predictions about the fuel mix in these countries. Nevertheless, if and when these countries deepen their capability to switch between natural gas and petroleum fuels based on price trends, such growth in natural gas markets could impact the general relationship between natural gas and crude oil prices globally.

A. Electricity generation in Japan and the European Union

The past decade or so has been characterized by rapid growth of natural gas-fired power generation capacity. As illustrated in Table 1 and Figure 2, in both the United States and other parts of the world the share of natural gas in the generation mix has risen substantially in the past 15 years. In the countries of the EU, collectively, the natural gas share of total generation increased from about 9.2% in 1990 to 17.9% in 2003, as natural gas has been displacing coal share and petroleum share in total generation. The growth in nuclear power led to a significant displacement of other fuels prior to the early 1990s. However, this share displacement has not led to a net loss in the total amount of power generated by coal as strong growth in total generation requirements over this period (1.81% per annum) has meant that the total amount of power generated from coal has risen. The amount of power generated from petroleum has fallen only slightly during this period as well. The increase in gas-fired generation in particular has enabled greater flexibility in the power generation system. The implication is that if natural gas prices were to rise relative to oil, it is reasonable to expect that petroleum generation capacity would be utilized more heavily, all else constant. This system flexibility is precisely what tends to link crude oil and natural gas prices through interfuel substitution. Notice that the plants themselves need not be switching capable, merely the dispatch system need be.

Looking back through 1970, we see that natural gas has risen in total share in the countries of the EU, fallen through the 1980s, and risen steadily since the early 1990s. During the 1970s, the oil shocks of the decade motivated diversification away from crude oil and petroleum products. This long-term switching behavior drove up natural gas prices in step with rising crude oil prices and ultimately led to the adoption of a newer technology – nuclear power (whose share of supply increased from 10.0% in 1979 to 36.4% in 1989). The recent rapid growth in natural gas use in the EU that has occurred as a result of the relatively low capital costs for combined cycle power generation units and environmental preferences has caused a run-up in natural gas prices, spurring increased interest in alternative technologies (such as renewable energy, nuclear energy and clean coal). These alternative fuels will become even more popular if natural gas prices move above their long run equilibrium relationship with crude oil and stay there for a prolonged period. In effect, switching to alternative technologies will eventually reduce incremental natural gas demand, easing prices and returning natural gas back to its equilibrium relationship with oil. If enough alternatives are adopted, and natural gas prices are driven below their long run equilibrium with crude oil, markets may adjust yet again by creating renewed demand for natural gas. However, environmental policy could play a key role in determining such market trends if fuels with higher carbon emissions are taxed or treated less favorably than those that are cleaner.

Figure 2: Generation by fuel type (EU and Japan, 1970-2003)



Source: World Bank (2006)

In Japan, the story is similar to that of the countries of the EU. Japanese natural gas share in electric power generation increased from 19.4% in 1990 to 24.7% in 2003, with much of the growth coming at the expense of petroleum-fired generation. Unlike in the EU, however, the percentage of coal-fired generation has increased in Japan. This expansion in coal use has been ongoing in Japan, driven largely by a desire for fuel diversification and the construction of super-critical coal facilities, which tend to be more environmentally acceptable than traditional coal plants. In addition, coal use has accelerated in recent years in the wake of nuclear outages in Japan in the early 2000s. The expansion of natural gas-fired generation capacity in Japan has enabled a high degree of fuel flexibility to utilities which still maintain incremental plant capability to shift between natural gas and oil.[2]

The trend toward natural gas in Japan is much more pronounced when one considers the mix of fuels used for power generation prior to the 1980s. Because Japan imports almost all of its energy, a move to become more diversified emerged following the oil price shocks of the 1970s. In the early 1970s, most of Japan's electricity generation was from oil. Rising world oil prices pushed Japan to seek alternative fuel sources, especially natural gas, coal and nuclear as a matter of government policy. Japan's Ministry of Economy, Trade and Industry provided generous financing and other support to industry to pursue imported LNG programs. Currently, natural gas makes up approximately 27.2% of all generation capacity in Japan, crude oil and petroleum another 27.0%, and nuclear 21.9% (see Figure 3). This long-term switching behavior in the Japanese electricity supply industry, motivated by an effort to diversify the generation mix and lower total costs, helps cement the relationship between crude oil and natural gas prices found in the U.S. data. The relatively high shares of oil and natural gas plants in the Japanese power system facilitate switching between oil and natural gas at the system-wide level as the relative price of the two fuels fluctuates.

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[2] Tokyo Electric and Chubu Electric are the two utility areas that have the greatest degree of flexibility, containing 41.5% and 21.7%, respectively, of all natural gas-fired capacity in Japan, and 23.5% and 17.2%, respectively, of all oil-fired generation capacity.

Table 1: Generation by fuel type (EU and Japan, 1970-2003)

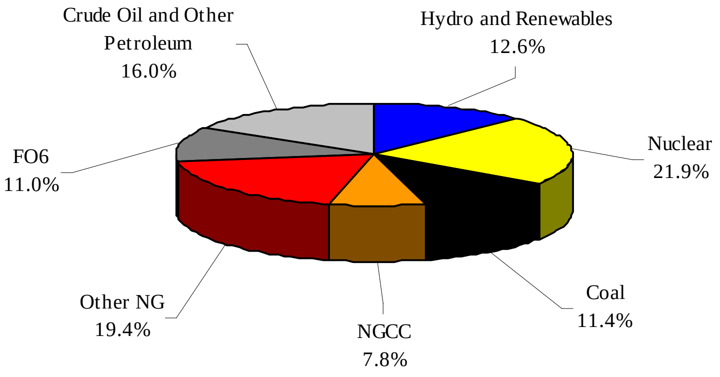
	European Union									
	Coal		Hydro		Natural gas		Nuclear		Petroleum	
	GWh	*% of total*	*GWh*	*% of total*	*GWh*	*% of total*	*GWh*	*% of total*	*GWh*	*% of total*
1970	325,796.5	42.9%	178,412.4	23.5%	54,299.4	7.1%	15,514.1	2.0%	186,169.4	24.5%
1971	345,963.2	42.0%	172,981.6	21.0%	65,897.8	8.0%	24,711.7	3.0%	214,167.7	26.0%
1972	337,421.0	38.4%	177,590.0	20.2%	88,795.0	10.1%	35,518.0	4.0%	239,746.5	27.3%
1973	345,616.9	36.0%	172,808.5	18.0%	115,205.6	12.0%	38,401.9	4.0%	288,014.1	30.0%
1974	349,135.2	35.4%	189,530.5	19.2%	139,654.1	14.1%	39,901.2	4.0%	269,332.8	27.3%
1975	336,095.4	34.3%	187,818.0	19.2%	148,277.4	15.2%	59,311.0	6.1%	247,129.0	25.3%
1976	401,431.5	37.0%	162,742.5	15.0%	151,893.0	14.0%	75,946.5	7.0%	292,936.5	27.0%
1977	400,553.3	36.4%	233,656.1	21.2%	144,644.2	13.1%	89,011.8	8.1%	233,656.1	21.2%
1978	423,908.6	36.4%	223,729.6	19.2%	141,302.9	12.1%	105,977.2	9.1%	270,830.5	23.2%
1979	445,502.9	36.0%	235,126.5	19.0%	148,501.0	12.0%	123,750.8	10.0%	284,626.8	23.0%
1980	468,395.9	37.4%	215,208.9	17.2%	126,593.5	10.1%	151,912.2	12.1%	291,165.0	23.2%
1981	472,878.5	37.4%	217,268.5	17.2%	102,244.0	8.1%	217,268.5	17.2%	255,610.0	20.2%
1982	501,270.9	39.4%	218,502.7	17.2%	102,824.8	8.1%	231,355.8	18.2%	218,502.7	17.2%
1983	513,487.2	39.4%	210,661.4	16.2%	105,330.7	8.1%	289,659.5	22.2%	184,328.8	14.1%
1984	525,471.2	38.4%	207,422.9	15.2%	124,453.7	9.1%	373,361.1	27.3%	138,281.9	10.1%
1985	533,703.5	36.6%	216,366.3	14.9%	115,395.4	7.9%	461,581.4	31.7%	129,819.8	8.9%
1986	517,606.9	35.4%	207,042.8	14.1%	118,310.2	8.1%	488,029.4	33.3%	133,098.9	9.1%
1987	521,913.3	34.7%	214,905.5	14.3%	122,803.1	8.2%	506,562.9	33.7%	138,153.5	9.2%
1988	522,022.7	33.3%	237,283.0	15.2%	126,551.0	8.1%	553,660.4	35.4%	126,551.0	8.1%
1989	554,903.8	34.3%	179,527.7	11.1%	130,565.6	8.1%	587,545.2	36.4%	163,207.0	10.1%
1990	562,229.4	34.7%	181,897.8	11.2%	148,825.4	9.2%	578,765.6	35.7%	148,825.4	9.2%
1991	559,725.9	33.7%	203,536.7	12.2%	135,691.1	8.2%	593,648.7	35.7%	169,613.9	10.2%
1992	548,208.0	32.3%	205,578.0	12.1%	137,052.0	8.1%	616,734.0	36.4%	188,446.5	11.1%
1993	513,976.8	30.3%	205,590.7	12.1%	154,193.0	9.1%	651,037.3	38.4%	171,325.6	10.1%
1994	524,427.3	30.6%	227,251.8	13.3%	157,328.2	9.2%	629,312.8	36.7%	174,809.1	10.2%
1995	537,679.8	30.6%	215,071.9	12.2%	179,226.6	10.2%	645,215.7	36.7%	179,226.6	10.2%
1996	537,155.1	29.6%	240,793.7	13.3%	185,225.9	10.2%	685,335.8	37.8%	166,703.3	9.2%
1997	524,060.0	28.6%	224,597.2	12.2%	224,597.2	12.2%	692,507.9	37.8%	168,447.9	9.2%
1998	535,512.3	28.6%	229,505.3	12.2%	248,630.7	13.3%	688,515.9	36.7%	172,129.0	9.2%
1999	526,161.7	27.6%	233,849.6	12.2%	272,824.6	14.3%	701,548.9	36.7%	175,387.2	9.2%
2000	565,393.6	28.6%	242,311.6	12.2%	302,889.4	15.3%	726,934.7	36.7%	141,348.4	7.1%
2001	557,426.9	28.1%	247,745.3	12.5%	309,681.6	15.6%	722,590.4	36.5%	144,518.1	7.3%
2002	561,452.1	28.1%	207,945.2	10.4%	332,712.3	16.7%	727,808.2	36.5%	166,356.2	8.3%
2003	603,423.5	29.5%	215,508.4	10.5%	366,364.3	17.9%	732,728.6	35.8%	129,305.0	6.3%

	Japan									
	Coal		Hydro		Natural gas		Nuclear		Petroleum	
	GWh	*% of total*	*GWh*	*% of total*	*GWh*	*% of total*	*GWh*	*% of total*	*GWh*	*% of total*
1970	60,316.0	17.2%	74,508.0	21.2%	3,548.0	1.0%	3,548.0	1.0%	209,332.0	59.6%
1971	45,948.0	12.0%	84,238.0	22.0%	3,829.0	1.0%	7,658.0	2.0%	241,227.0	63.0%
1972	42,570.0	10.0%	85,140.0	20.0%	4,257.0	1.0%	8,514.0	2.0%	285,219.0	67.0%
1973	37,231.0	8.1%	65,154.2	14.1%	9,307.7	2.0%	9,307.7	2.0%	339,732.5	73.7%
1974	41,127.8	9.0%	82,255.7	18.0%	13,709.3	3.0%	18,279.0	4.0%	301,604.2	66.0%
1975	42,583.1	9.0%	85,166.3	18.0%	18,925.8	4.0%	23,657.3	5.0%	302,813.4	64.0%
1976	45,629.3	9.0%	81,118.7	16.0%	25,349.6	5.0%	35,489.4	7.0%	319,405.0	63.0%
1977	47,643.4	9.0%	74,111.9	14.0%	37,056.0	7.0%	31,762.3	6.0%	338,797.4	64.0%
1978	44,621.8	8.0%	72,510.4	13.0%	55,777.2	10.0%	61,354.9	11.0%	323,507.7	58.0%
1979	52,680.6	9.0%	81,947.6	14.0%	70,240.8	12.0%	70,240.8	12.0%	310,230.2	53.0%
1980	57,253.1	10.1%	85,879.7	15.2%	80,154.3	14.1%	80,154.3	14.1%	263,364.3	46.5%
1981	63,830.4	11.0%	87,041.4	15.0%	81,238.6	14.0%	87,041.4	15.0%	261,124.2	45.0%
1982	69,445.7	12.1%	81,020.0	14.1%	81,020.0	14.1%	104,168.5	18.2%	237,272.7	41.4%
1983	79,871.0	13.1%	86,014.9	14.1%	92,158.8	15.2%	116,734.5	19.2%	233,469.0	38.4%
1984	90,070.3	14.3%	70,769.5	11.2%	122,238.2	19.4%	135,105.4	21.4%	212,308.5	33.7%
1985	100,041.1	15.3%	80,032.9	12.2%	126,718.8	19.4%	160,065.8	24.5%	186,743.5	28.6%
1986	100,665.6	15.3%	80,532.5	12.2%	127,509.8	19.4%	167,776.0	25.5%	181,198.1	27.6%
1987	106,951.6	15.5%	71,301.1	10.3%	135,472.1	19.6%	185,382.9	26.8%	192,513.0	27.8%
1988	112,220.2	15.3%	89,776.2	12.2%	142,145.6	19.4%	179,552.4	24.5%	209,477.8	28.6%
1989	119,052.8	15.3%	95,242.2	12.2%	150,800.2	19.4%	182,547.6	23.5%	230,168.7	29.6%
1990	116,833.8	14.3%	91,798.0	11.2%	158,560.1	19.4%	200,286.5	24.5%	250,358.1	30.6%
1991	129,404.4	15.2%	94,896.6	11.1%	172,539.2	20.2%	215,674.0	25.3%	241,554.9	28.3%
1992	130,400.0	15.3%	78,240.0	9.2%	173,866.6	20.4%	226,026.6	26.5%	243,413.2	28.6%
1993	140,373.6	16.3%	96,506.9	11.2%	175,467.0	20.4%	245,653.8	28.6%	201,787.1	23.5%
1994	158,996.9	17.2%	65,469.3	7.1%	187,055.2	20.2%	271,230.0	29.3%	243,171.8	26.3%
1995	172,712.2	18.2%	86,356.1	9.1%	191,902.4	20.2%	287,853.6	30.3%	211,092.6	22.2%
1996	176,466.8	18.4%	78,429.7	8.2%	205,877.9	21.4%	303,915.0	31.6%	196,074.2	20.4%
1997	190,764.6	19.4%	90,362.2	9.2%	210,845.0	21.4%	321,287.7	32.7%	170,684.1	17.3%
1998	191,854.6	19.4%	90,878.5	9.2%	222,147.4	22.4%	333,221.1	33.7%	151,464.1	15.3%
1999	215,801.9	21.4%	82,210.2	8.2%	236,354.4	23.5%	318,564.7	31.6%	154,144.2	15.3%
2000	241,125.8	23.5%	83,869.8	8.2%	241,125.8	23.5%	324,995.6	31.6%	136,288.5	13.3%
2001	257,503.2	25.5%	82,401.0	8.2%	236,903.0	23.5%	319,304.0	31.6%	113,301.4	11.2%
2002	272,718.9	26.5%	83,913.5	8.2%	241,251.4	23.5%	293,697.3	28.6%	136,359.5	13.3%
2003	290,547.0	28.9%	93,390.1	9.3%	249,040.3	24.7%	238,663.6	23.7%	134,896.8	13.4%

Source: World Bank (2006)

The analysis of crude oil and natural gas prices in the United States done in Hartley, Medlock and Rosthal (2007) reveals that the relationship between crude oil and natural gas prices has changed in recent years as a result of the development of natural gas-fired combined cycle gas turbines (NGCC). In particular, NGCC plants have a higher thermal efficiency (or lower heat rate) than conventional steam turbines or single cycle combustion turbines. The construction of NGCC facilities makes natural gas, for a given price, a more competitive fuel source than residual fuel oil in electric generation. The result has been a shift in the long-term relative price of natural gas to oil. It therefore is important to gauge whether NGCC has had, or will have, a similar effect in Japan and the EU.

Figure 3: Japanese installed capacity by fuel type (2003)



Total Capacity = 200,000 MW

Source: Medlock and Hartley (2004)

From Figure 3, we see that Japanese combined cycle capacity is approximately 7.8% of the total generation capacity in Japan. Much of this is relatively new construction, and utility plans as of 2004 had an additional 11,685 megawatts (MW) on the ground by 2012, resulting in a 75% increase in NGCC capacity. This type of growth will certainly change the marginal cost of generation for a given set of fuel prices and a given demand. Thus, it is reasonable to expect NGCC operators to pay prices that are competitive with the next fuel source in the stack, namely residual fuel oil. Given the lower cost of generation in a NGCC facility, it is likely that Japanese power generators will be able to afford to pay a higher natural gas price and thus, we can expect the price relationship between crude oil and natural gas to come to resemble that currently in the United States. In sum, the relative heat rates will matter for pricing since fuels compete on a cost basis rather than price.

Unfortunately, data limitations prevent an analysis, at least at this point, of the amount of NGCC capacity in the EU. However, anecdotal evidence indicates that the bulk of gas demand growth in the EU stems from construction of new NGCC units. This is certainly true of the United Kingdom, where NGCC was used quite extensively after both the North Sea natural gas finds and the deregulation of the U.K. electricity industry. Thus, we should expect the same sort of gas-to-oil pricing relationships to emerge in the EU as in the United States.

B. Industrial demand for natural gas

In the industrial sector, analysis of U.S. data revealed a significant drop in industrial demand for natural gas following increases in the real price of natural gas. However, there was little evidence to support fuel switching between natural gas and crude oil. In addition, some of the econometrically estimated negative response to natural gas prices may have taken the form of plant closures and relocation and/or curtailed production rather than changes in the type of fuel used. Still further, some of the demand loss, in paper manufacturing or primary metal manufacturing for example, may have involved switching between natural gas and fuel sources other than oil.

Evidence suggests that an indirect link between crude oil and natural gas prices exists in the industrial sector via the price of electricity, which appears to have a significant influence on industrial natural gas demand. Cogeneration in industrial facilities thus appears to reinforce the linkage between natural gas and crude oil prices that arises from fuel switching in the electricity sector more generally. The industrial sector could also facilitate substitution between natural gas and oil products if the industrial plant found it more cost effective to buy electricity from the grid than to buy natural gas to generate electricity on-site. Specifically, if natural gas prices were to rise, industrial consumers would choose to buy electricity rather than generate it, thereby raising electricity demand and forcing power system operators to minimize costs through dispatch decisions that weigh the relative costs of natural gas and crude oil. Thus, any decision to increase natural gas consumption at the cogeneration site would closely match the opportunities reflected in the electricity industry more generally.

Despite the lack of evidence of fuel switching in the industrial sector, consumption of natural gas in the sector could be contributing to the short run adjustment of crude oil and natural gas prices in Europe and Japan. A negative demand response to higher natural gas prices could materialize by firms relocating operations to different countries, simply reducing output, or adopting more energy-efficient means of production.

Figure 4 and Table 2 indicate the trends in both the EU and Japan since 1970. In both regions, though more pronounced in the EU, both natural gas and electricity have increased their share of total industrial energy demand. Much of this increase has been at the expense of petroleum, and, in the EU, of coal as well.[3]

It is not possible to say precisely what the historical trends in the EU and Japan imply about fuel switching in the industrial sector in these regions without a full analysis, as was done for the United States. Nevertheless, the behavior is consistent with what was observed in the United States over the same time period (see Table 3 and Figure 5). In all regions, petroleum use diminished in favor of electricity and natural gas. Data limitations make it difficult to assess which industrial sectors in the EU and Japan have been most responsible for the observed trends. But, in general, industrial consumers now rely more heavily on electricity generated off-site than in the past. Thus, the activity in the power generation sectors in these regions, just as in the United States, seems critical, and fuel switching via dispatch decisions by grid operators will promote a link between crude oil and natural gas prices.

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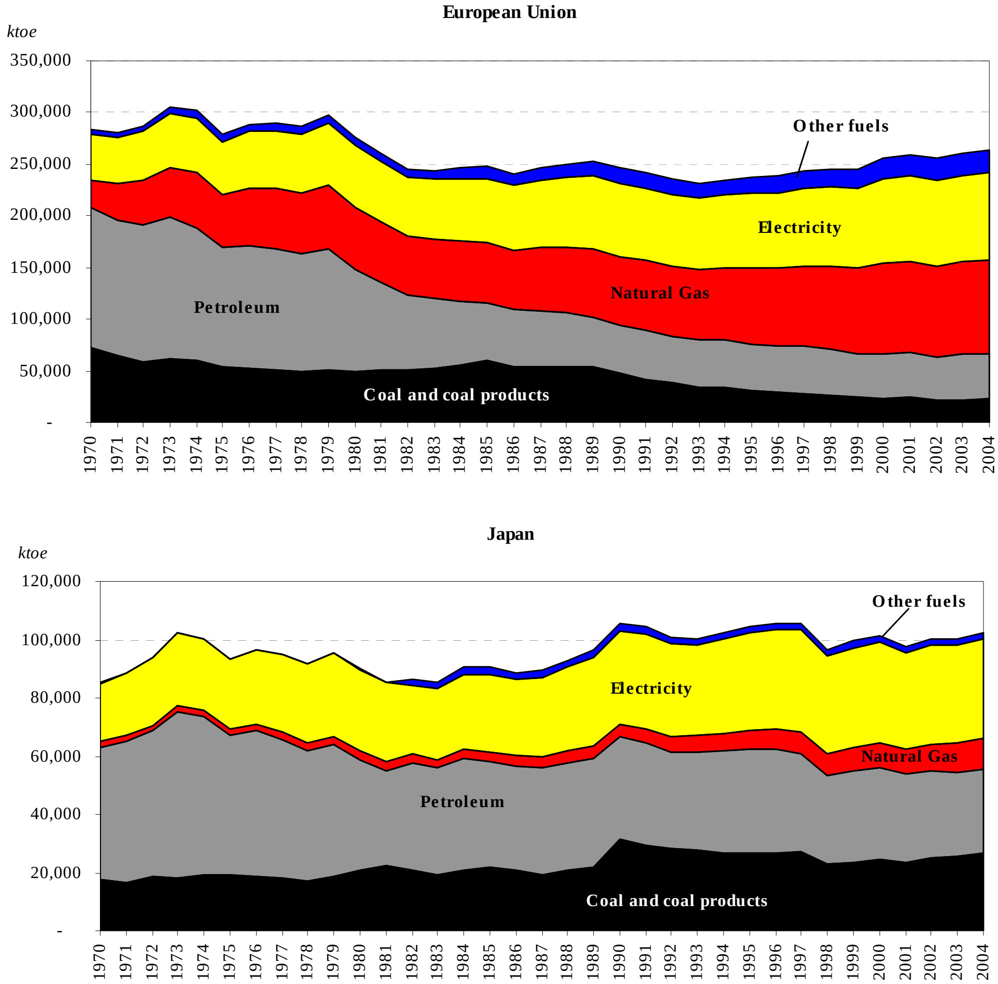
[3] It is interesting to note that the reduction in coal use in the European Union coincides with the reunification of Germany and the closure of previously subsidized coal mines in the United Kingdom. Thus, it is not necessarily true that the switch from coal in favor of natural gas is purely motivated by economic factors.

Figure 4: Industrial energy demand by fuel type (EU and Japan, 1970-2004)



Source: IEA Energy Balances of OECD Countries (2006)

Table 2: Industrial energy demand by fuel type (EU and Japan, 1970-2004)

Note: Shares in tables do not sum to one because the category "Other" is omitted

	European Union							
	Coal and Coal Products		Petroleum Products		Natural Gas		Electricity	
	ktoe	*% of total*	*ktoe*	*% of total*	*ktoe*	*% of total*	*ktoe*	*% of total*
1970	72,812	25.6%	134,905	47.5%	27,218	9.6%	43,863	15.4%
1971	64,644	23.0%	131,907	46.9%	34,541	12.3%	44,993	16.0%
1972	58,978	20.5%	132,388	46.1%	42,669	14.9%	47,512	16.5%
1973	61,784	20.2%	136,734	44.8%	48,053	15.7%	52,046	17.0%
1974	60,164	19.9%	128,417	42.5%	52,900	17.5%	53,582	17.7%
1975	53,250	19.1%	116,479	41.8%	50,771	18.2%	51,001	18.3%
1976	52,778	18.3%	118,655	41.1%	55,475	19.2%	54,728	18.9%
1977	50,199	17.3%	117,351	40.5%	59,066	20.4%	55,800	19.3%
1978	48,775	17.0%	115,164	40.2%	57,498	20.1%	57,669	20.1%
1979	50,494	17.0%	117,301	39.4%	61,571	20.7%	60,331	20.3%
1980	49,647	18.0%	98,850	35.9%	59,951	21.8%	59,332	21.5%
1981	51,415	19.8%	83,560	32.1%	59,158	22.7%	58,507	22.5%
1982	51,024	20.9%	72,736	29.7%	56,259	23.0%	57,246	23.4%
1983	52,133	21.4%	68,824	28.3%	56,215	23.1%	58,117	23.9%
1984	56,207	22.8%	60,694	24.6%	58,128	23.6%	60,708	24.6%
1985	59,654	24.1%	56,262	22.7%	58,432	23.6%	62,008	25.0%
1986	53,938	22.4%	56,162	23.3%	56,381	23.4%	63,118	26.2%
1987	53,725	21.8%	53,559	21.8%	61,882	25.2%	64,876	26.4%
1988	54,238	21.8%	51,785	20.8%	63,026	25.3%	67,866	27.2%
1989	54,323	21.5%	48,113	19.1%	66,098	26.2%	70,328	27.9%
1990	48,283	19.6%	45,833	18.6%	66,802	27.1%	70,010	28.4%
1991	41,486	17.1%	47,871	19.8%	67,752	28.0%	69,888	28.9%
1992	37,883	16.1%	45,171	19.2%	68,052	28.9%	69,757	29.7%
1993	33,224	14.3%	46,426	20.0%	68,712	29.6%	68,853	29.7%
1994	33,357	14.2%	47,026	20.0%	69,676	29.7%	69,701	29.7%
1995	30,594	12.9%	45,401	19.1%	73,980	31.1%	71,498	30.1%
1996	28,648	12.0%	45,112	18.8%	76,088	31.8%	72,027	30.1%
1997	28,419	11.7%	45,465	18.7%	77,662	31.9%	74,460	30.6%
1998	26,605	10.9%	44,534	18.2%	80,286	32.8%	76,061	31.0%
1999	24,202	9.8%	41,755	17.0%	82,841	33.7%	77,629	31.6%
2000	23,415	9.1%	43,086	16.8%	87,475	34.1%	82,392	32.1%
2001	23,953	9.3%	44,555	17.2%	87,290	33.7%	83,304	32.2%
2002	21,138	8.3%	42,734	16.7%	87,761	34.4%	83,323	32.7%
2003	21,548	8.3%	44,409	17.1%	89,723	34.5%	83,835	32.2%
2004	22,641	8.6%	43,936	16.6%	90,781	34.3%	85,135	32.2%

	Japan							
	Coal and Coal Products		Petroleum Products		Natural Gas		Electricity	
	ktoe	*% of total*	*ktoe*	*% of total*	*ktoe*	*% of total*	*ktoe*	*% of total*
1970	17,711	20.8%	45,262	53.2%	1,847	2.2%	19,771	23.2%
1971	16,321	18.4%	48,958	55.2%	2,167	2.4%	20,905	23.6%
1972	18,913	20.2%	49,729	53.0%	2,022	2.2%	22,988	24.5%
1973	18,218	17.8%	56,946	55.6%	2,066	2.0%	25,059	24.5%
1974	18,990	19.0%	54,659	54.6%	2,145	2.1%	24,304	24.3%
1975	19,295	20.7%	47,721	51.2%	2,111	2.3%	24,085	25.8%
1976	18,860	19.5%	49,874	51.6%	2,152	2.2%	25,797	26.7%
1977	18,151	19.1%	47,529	50.1%	2,679	2.8%	26,429	27.9%
1978	16,882	18.4%	44,839	48.8%	2,585	2.8%	27,549	30.0%
1979	18,621	19.5%	45,384	47.4%	2,628	2.7%	28,989	30.3%
1980	20,822	23.2%	38,067	42.4%	2,731	3.0%	28,190	31.4%
1981	22,491	26.3%	32,688	38.2%	2,778	3.2%	27,564	32.2%
1982	20,598	23.8%	37,268	43.1%	2,757	3.2%	23,723	27.4%
1983	18,986	22.2%	36,860	43.1%	2,788	3.3%	24,721	28.9%
1984	20,943	23.1%	38,099	42.1%	3,130	3.5%	26,068	28.8%
1985	21,656	24.0%	36,503	40.4%	3,356	3.7%	26,542	29.4%
1986	20,684	23.4%	36,079	40.8%	3,381	3.8%	26,130	29.5%
1987	19,336	21.6%	36,803	41.2%	3,537	4.0%	27,418	30.7%
1988	21,061	22.6%	36,754	39.5%	3,786	4.1%	29,063	31.2%
1989	21,811	22.6%	37,373	38.8%	4,158	4.3%	30,653	31.8%
1990	31,361	29.8%	35,218	33.4%	4,382	4.2%	31,876	30.3%
1991	29,566	28.3%	35,091	33.6%	4,860	4.7%	32,371	31.0%
1992	28,025	27.8%	33,460	33.2%	5,204	5.2%	31,761	31.5%
1993	27,598	27.5%	33,685	33.5%	5,655	5.6%	31,311	31.2%
1994	26,508	25.8%	35,214	34.3%	6,062	5.9%	32,565	31.7%
1995	26,787	25.6%	35,664	34.1%	6,575	6.3%	33,172	31.7%
1996	26,890	25.4%	35,599	33.6%	6,989	6.6%	34,050	32.2%
1997	27,010	25.6%	33,821	32.0%	7,655	7.2%	34,735	32.9%
1998	23,046	23.8%	30,326	31.4%	7,437	7.7%	33,589	34.7%
1999	23,552	23.7%	31,586	31.7%	7,904	7.9%	34,103	34.3%
2000	24,424	24.1%	31,517	31.1%	8,454	8.3%	34,733	34.2%
2001	23,210	23.8%	30,552	31.3%	8,491	8.7%	33,351	34.1%
2002	24,906	24.8%	30,263	30.2%	9,093	9.1%	33,665	33.5%
2003	25,334	25.3%	29,304	29.2%	9,763	9.7%	33,638	33.5%
2004	26,587	26.0%	28,720	28.1%	10,816	10.6%	33,879	33.1%

Source: IEA Energy Balances of OECD Countries (2006)

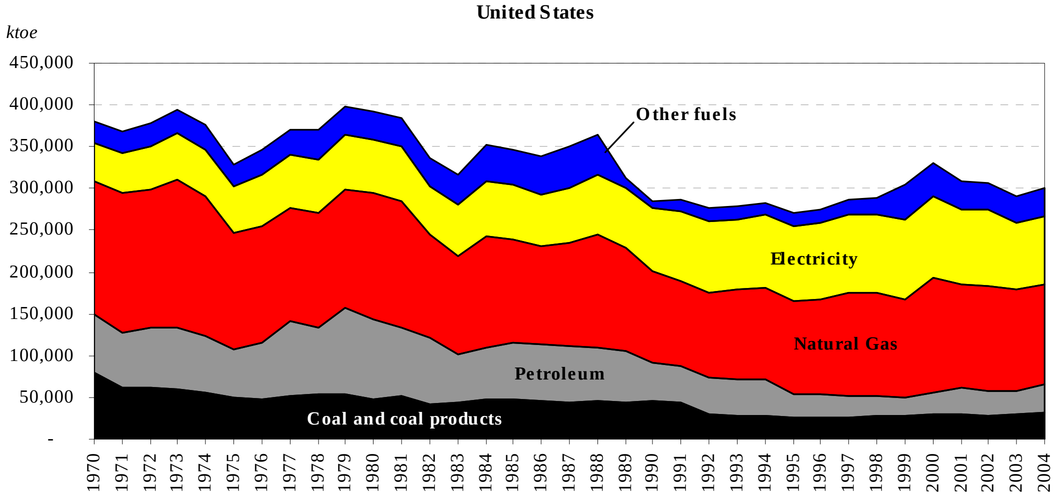
Table 3: Industrial energy demand by fuel type (United States, 1970-2004)

Note: Shares in tables do not sum to one because the category "Other" is omitted

	United States							
	Coal and Coal Products		Petroleum Products		Natural Gas		Electricity	
	ktoe	*% of total*	*ktoe*	*% of total*	*ktoe*	*% of total*	*ktoe*	*% of total*
1970	80,197	21.1%	68,647	18.1%	160,277	42.2%	45,276	11.9%
1971	61,285	16.6%	66,789	18.1%	165,964	45.0%	49,241	13.4%
1972	61,356	16.2%	72,734	19.2%	165,078	43.6%	52,042	13.7%
1973	60,153	15.3%	72,589	18.4%	177,300	45.0%	55,539	14.1%
1974	56,366	15.0%	66,360	17.7%	168,452	44.9%	55,735	14.8%
1975	50,427	15.4%	57,185	17.4%	139,383	42.5%	54,705	16.7%
1976	48,722	14.1%	67,394	19.5%	139,485	40.4%	60,049	17.4%
1977	51,711	13.9%	89,244	24.0%	136,522	36.8%	62,284	16.8%
1978	53,127	14.4%	80,598	21.8%	137,412	37.2%	64,016	17.3%
1979	53,230	13.3%	104,980	26.3%	140,294	35.1%	66,172	16.6%
1980	48,247	12.3%	95,194	24.2%	151,529	38.5%	64,168	16.3%
1981	51,492	13.4%	81,340	21.2%	152,059	39.6%	64,843	16.9%
1982	42,063	12.5%	80,228	23.9%	122,406	36.4%	57,530	17.1%
1983	43,764	13.8%	57,821	18.2%	118,385	37.3%	60,040	18.9%
1984	47,827	13.6%	62,109	17.6%	132,300	37.6%	66,030	18.8%
1985	47,624	13.7%	67,203	19.4%	124,344	35.9%	65,577	18.9%
1986	45,967	13.6%	68,138	20.2%	116,595	34.5%	62,957	18.6%
1987	44,560	12.7%	67,097	19.1%	123,652	35.3%	66,058	18.8%
1988	46,673	12.8%	63,671	17.4%	134,779	36.9%	70,534	19.3%
1989	43,633	14.0%	61,371	19.7%	123,783	39.7%	72,583	23.3%
1990	44,839	15.7%	47,234	16.5%	109,886	38.5%	74,523	26.1%
1991	43,997	15.4%	42,685	14.9%	103,022	36.1%	82,346	28.8%
1992	29,641	10.7%	43,787	15.8%	101,995	36.7%	84,693	30.5%
1993	27,662	9.9%	43,274	15.5%	107,799	38.6%	85,031	30.5%
1994	27,879	9.8%	43,648	15.4%	109,393	38.6%	88,552	31.2%
1995	26,286	9.7%	27,019	9.9%	112,098	41.2%	89,559	33.0%
1996	25,464	9.3%	27,863	10.1%	114,104	41.5%	91,205	33.2%
1997	26,839	9.4%	24,563	8.6%	124,809	43.6%	91,769	32.1%
1998	27,495	9.5%	23,670	8.2%	124,149	43.1%	93,013	32.3%
1999	28,741	9.5%	20,298	6.7%	118,550	39.0%	95,964	31.6%
2000	29,075	8.8%	25,947	7.8%	137,881	41.6%	98,222	29.7%
2001	29,414	9.5%	31,851	10.3%	123,211	39.9%	90,325	29.2%
2002	27,948	9.1%	28,881	9.4%	125,788	41.0%	93,092	30.3%
2003	29,335	10.1%	28,811	9.9%	120,481	41.3%	80,480	27.6%
2004	31,181	10.4%	34,545	11.5%	120,382	40.1%	81,003	27.0%

Source: IEA Energy Balances of OECD Countries (2006)

Figure 5: Industrial energy demand by fuel type (United States, 1970-2004)



Source: IEA Energy Balances of OECD Countries (2006)

IV. Supply-side influences

Our discussion, until now, has focused on demand-side factors influencing substitution between natural gas and oil in the electricity and industrial sector, primarily because we have used the analysis of U.S. prices, which focused on demand, as a starting point. We cannot ignore, however, other factors that influence the relationship between crude oil and natural gas prices. We begin with a discussion of supply-side influences, noting that production decisions also influence gas and oil price movements. Ultimately, however, as long as generating capacity fired by natural gas and oil products remains competitive in major electricity systems, the ability to switch between fuels in generating electricity should tie down the long run relative price.

A. Associated natural gas production

In many producing regions around the world, a substantial amount of natural gas production is associated with crude oil production. This is a function of geology, and natural gas has been heretofore flared as a by-product of oil production. However, with decreasing costs of transportation to markets and rising demand, producers are increasingly pursuing commercial development of associated gas production. The realization of value of associated natural gas establishes an important supply-side link between crude oil and natural gas prices, particularly because they are in many instances jointly produced commodities.

If natural gas is associated, oil field operators have several options. They can flare the gas, use it on-site for daily operations, reinject it to enhance recovery of crude oil, or market it. The use of gas for on-site operations can be done even if other options are used because the associated gas is an inexpensive fuel source for daily operations.

The decision to flare, re-inject, or market natural gas depends on its price relative to crude oil, as well as its absolute price. For example, assuming there is some long run equilibrium relationship between crude oil prices and natural gas prices (maintained by switching in the electricity sector), if the price of natural gas rises above this equilibrium level, then oil producers will benefit from commercializing and marketing the natural gas.

As more associated gas production comes to market, eventually the added natural gas supplies will lower the price of natural gas back to a long-term equilibrium level with oil prices, discouraging further investment in natural gas supply. Conversely, if natural gas falls below its long run equilibrium, then oil producers will choose to re-inject the natural gas in order to increase the supply of oil, which in this case becomes the more highly valued commodity. Other use of the natural gas, such as GTL production or consumption for tar sands development, may also become attractive if the natural gas price falls below its long run equilibrium relationship with oil prices. In these cases, the higher oil production will eventually lead to a relative easing of oil prices, while at the same time the suspension of future natural gas investments for export will tighten natural gas markets, helping bring the two commodity prices back to their long-term equilibrium relationship.

However, if the additional value created through either marketing or re-injecting the natural gas is not profitable, then flaring may be considered the optimal decision. Crucial to price adjustment trends is the calculation of the opportunity cost to flare natural gas. When natural gas can be used to enhance oil recovery, re-injection can result in greater profits via indirect revenues from additional oil production. Alternatively, when natural gas can be marketed, the resulting revenues also can raise profits. In addition, both cases can result in a longer production life for the field. This follows from the fact that indirect or direct natural gas revenues will help defray the cost of oil field operations, so long as they exceed the costs required to execute either of these options. In fact, it can be shown that commercial quantities of associated natural gas reduce the hurdle for oil field development in certain cases.

The preceding argument depends critically on a producer’s expectation regarding prices and costs in the long term since it is generally not a simple matter to switch between marketing and re-injecting gas. As a result, the overall implications of associated natural gas production for the relationship between natural gas and crude oil prices are not necessarily so clear. For example, an oil producer will generally produce more oil, and therefore also associated natural gas, when oil prices are high. If facilities are not in place to re-inject the gas and there is no market outlet for the additional gas production, the increased production of natural gas is likely to reduce the gas price in that immediate region, likely resulting in gas being flared. Thus, a short term (and localized) gap will be driven between crude oil and natural gas prices as the associated gas production contributes to a negative correlation between natural gas and oil prices. However, such gaps encourage arbitrage and investment behavior that ultimately eliminates them, such as the construction of LNG export capabilities (as in Nigeria, for example) or GTL plants (as in Qatar and under consideration in Alaska).

Iran bears mention here because it uses a large proportion of its natural gas production for enhanced recovery of oil. In fact, it pipes nonassociated gas to separate aging oil fields to be used in enhanced recovery operations. Thus, increased oil production results in decreased Iranian natural gas export supply to the outside world. If oil prices remain high relative to historical standards, then this policy is unlikely to change in the near future. Oil revenues are simply too important to the Iranian national economy. However, as the foregone revenues from natural gas exports rise, there will be pressure to monetize more of Iran’s vast natural gas resource.

In Saudi Arabia, a different dilemma exists. In the 1990s, the kingdom burned up to 350,000 b/d of crude oil per year to meet growing electricity demand. During the summer electricity peak, Saudi domestic oil use would rise above 1 million b/d, greatly reducing the volume of highly valued crude oil available for export. This dilemma caused the Saudi oil sector to investigate how to develop more nonassociated natural gas resources to fuel power stations to free up oil for export. As electricity demand in the kingdom grows, this trade-off serves to link oil and gas price movements, especially if natural gas production does not keep pace with power generation requirements.

B. Nonassociated natural gas production

Nonassociated natural gas production also contributes to a link between crude oil and natural gas prices. Virtually all natural gas produced contains other hydrocarbons, as well as nonhydrocarbon gases. During processing the other hydrocarbons, or natural gas liquids (NGLs), are removed from the methane stream. The value of the NGLs is generally linked to crude oil, since they are also by-products of oil production and can also be used as inputs into the oil refining process. Therefore, if crude oil prices rise, the value of NGLs will also rise. This in turn encourages the production of “leaner” gas by removing as much of the NGLs as possible, which marginally reduces the volume of natural gas that remains to be marketed. On the other hand, when natural gas prices are high, inert gases can be mixed with the production stream so that the NGLs can be left in the gas stream. This renders the gas to an appropriate British thermal unit (BTU) content and marginally increases the volume of natural gas. In either case, the supply response tends to push natural gas and crude oil prices back toward their long run equilibrium relationship. In the longer term, a higher price for NGLs can allow production from some natural gas fields that might otherwise be non-economic. For example, the presence of substantial NGLs was a significant factor in facilitating the early development of some natural gas fields in Australia which might otherwise have been noneconomic at that time.

C. Unconventional oil production, gas-to-liquids (GTL), and crude oil refining

Unconventional oil production is another factor that may contribute to a positive correlation between oil and natural gas prices. Increased output from Canadian tar sands projects, for example, will require an increased input of natural gas.[4] Thus, higher oil prices will lead producers to use natural gas for tar sands production instead of marketing it to end-user sectors. This, in turn, will reduce natural gas supply potentially pushing up natural gas prices, reinforcing the positive correlation between natural gas and oil prices.

Gas-to-liquids (GTL) projects also can contribute to a positive link between crude oil and natural gas prices. When oil prices are high, converting low-cost natural gas (as in Qatar) to a clean-burning diesel suitable for transportation fuel becomes an attractive venture. Qatar is forecast to produce up to 800,000 b/d of GTL over the next decade or so. This will effectively remove natural gas supply from the market, thus contributing to higher natural gas prices while effectively adding more oil.

The composite weight of the global crude oil mix could also influence the relative value of natural gas compared to crude oil. As a higher proportion of the world's oil production becomes heavy crude oil, as some analysts are expecting, refiners' output will

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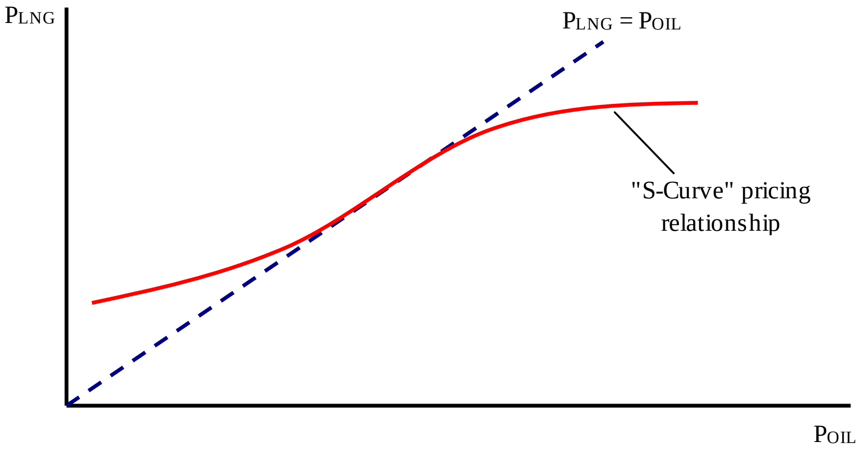
[4] In fact, the NEB in Canada projects that increased production of unconventional oil from the Athabasca tar sands will require virtually all of the natural gas forecast to be produced in the Canadian Arctic. Therefore, this gas production will have no direct impact on North American natural gas supply.

produce more residual fuel oil by virtue of this feedstock quality change. This could affect the relative value of natural gas, as higher fuel oil output from refineries would depress fuel oil price thus favoring it over natural gas where possible. However, over time, any sustained decline in fuel oil prices would prompt refineries to invest in equipment that could minimize their fuel oil output and increase the proportion of light products, like gasoline, that could be garnered from processing heavy crude oil. Thus, the long run price relationship between crude oil and natural gas could shift, reflecting the fixed costs incurred to refine the heavier crude oils to produce petroleum products that are more highly valued than fuel oil. Nevertheless, so long as the relative costs of production of gas and fuel oil do not adjust so much as to entirely eliminate one fuel or the other as an input into electricity generation, both fuels will remain as effective substitutes in the generation of electricity. Thus, the heat rates of different power generation types will continue to have bearing on the long run relationship between the two fuel prices.

V. The influence of contracts

Current practice in international energy markets provides evidence that market participants expect crude oil and natural gas prices to satisfy a long-term stable relationship. Specifically, many long-term contracts for the supply of LNG explicitly link natural gas and oil prices. Many European delivery contracts (both pipeline and LNG) tie the price of natural gas to a basket of crude oil products, which themselves are a function of Brent crude. In Asia, contract terms tend to link natural gas prices to the Japanese Crude Cocktail (JCC) price. It should be pointed out here, however, that parties would be reluctant to agree to such contract terms if there was not an expectation that market equilibrium prices would tend to revert to a stable long run relationship.

Figure 6: An illustration of the "S-curve" concept



In Japan and South Korea, many LNG contracts have stipulated an S-curve relationship to the JCC composite oil import price. The S-curve concept is illustrated in Figure 6. Over a fairly broad range, natural gas contract prices are closely related to the crude oil price. But, for a very low or very high oil price the contract price of natural gas departs from crude oil prices. This effectively places a collar on the delivered price of natural gas, limiting the risk of either very high or very low crude oil prices. Such a collar on natural gas prices can encourage diversion and/or increased demand when oil prices move outside of the linear portion of the S-curve relationship.

The historical practice of explicitly linking LNG prices to crude oil prices is changing somewhat. More recent contracts, such as those signed by parties in China and India, involve prices that are less closely linked to oil prices. In addition, contracts for delivery into Europe have been initiated that relate LNG prices to spot market natural gas prices such as at the UK National Balancing Point (NBP) or Zeebrugge – regions with so called gas-on-gas pricing.[5] This mirrors the U.S. practice where LNG import prices are

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[5] It can be argued that moving toward liquid natural gas pricing points as a basis for contract terms is an inevitable result of deregulation. In the past, a lack of a liquid pricing point exposed parties to a great degree of risk that simply could not be hedged unless through cross-commodity arrangements, and by

related to prices quoted for delivery at the Henry Hub. Since the U.S. market price for natural gas is related to oil prices, however, fixing LNG import prices to oil prices via a formula may not in practice lead to a very different outcomes – crude oil and natural gas prices will still be linked.

Recent contracts for importing LNG also have permitted buyers to divert LNG cargoes if market conditions warrant it. This option can potentially reduce the importance of the explicit linkage between oil and gas prices in the underlying contracts in Europe and Asia. These diversion clauses suggest that the opportunities to exploit price differentials by reselling cargoes to another market have been increasing. One explanation is simply that pricing formulas used in different locations have produced prices that are inconsistent with each other, thereby driving arbitrage between higher- and lower-cost markets. Another explanation is that seasonal swings in demand can result in diversion of cargoes to higher-valued markets at particular times of the year. This short-term shifting of supplies will eventually eliminate the price differential between two regions by reducing downward price pressure in the oversupplied market where the cargo was originally destined and increasing supply to the new (higher-priced) market of destination. It is important to point out that reductions in LNG shipping costs have increased the opportunities to exploit such price differentials. In addition, future developments in LNG liquefaction and regasification will tend to reinforce relationships between regional natural gas markets. Thus, diversion strategies may become increasingly utilized to capitalize on structural or temporary pricing discontinuities between different regional markets. It follows, as discussed in Section II above, if regional differentials push natural gas prices out of their long run equilibrium with crude oil prices, diversion can help to "right the ship" back to a global equilibrium level.

Diversion rights in LNG contracts might also be a means of exploiting different opportunities for storage around the world. In particular, the United States and Canada have substantial storage capabilities and potential for expansion. They therefore could serve as a storage "hub" for the Atlantic Basin, which would intensify the diversion of

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linking natural gas prices to oil prices the risk inherent in cross-commodity hedging is removed. With the emergence of liquid points such as NBP, risk mitigation strategies through gas trading are now possible.

cargoes between the EU and North America when prices justify it. If, for example, natural gas inventories are abnormally high in the United States, there will be downward pressure on natural gas prices in the United States, and deliveries of LNG into the North American market will be discouraged. Under such circumstances, cargoes will remain or be shifted to other, less-depressed markets in Europe or Asia, eventually bringing prices down there as well, transmitting the impact of high inventories across the globe and bringing regional natural gas prices into some long-term equilibrium. Alternatively, if U.S. storage is low, prompting higher prices in North America, but demand in Asia is falling, LNG sellers might choose to sell in the United States until prices equilibrate. At that point, sellers may still store extra supplies in the Atlantic Basin to substitute later to meet ongoing U.S. commitments and divert future U.S. shipments back to Asia when demand recovers abroad. Given the evidence that electricity markets in the United States push crude oil and natural gas into equilibrium, increasing connectedness of North American and global markets will tend to reinforce a link between crude oil and natural gas prices in all markets.

VI. The influence of geopolitics, environmental policy and cartel behavior

Geopolitics may also play a role in the future relationship between crude oil and natural gas prices. The growth of Russia as major supplier of both oil and natural gas, for example, has introduced a potentially interesting new dynamic into world energy markets. Russia is developing as a major non-OPEC supplier of oil. This would give it the capacity, for example, to reduce the price discrimination practiced by OPEC against Northeast Asian oil importers if it so desires. Conversely, while Russia is a larger exporter of natural gas than OPEC, the countries of the Middle East are emerging as potentially large suppliers of natural gas to Asia, Europe, and possibly North America. Producers in the Middle East might be able to undercut Russian attempts to extract additional rents from natural gas just as Russia might be in a symmetric position to undercut Middle East suppliers to grab a price premium for crude oil sales to Asia. It would be interesting to analyze a game in which both parties recognize at once the substitutability between natural gas and oil as energy sources and their abilities to supply products in either market.

The fact that a large proportion of the world’s proven and potential natural gas resource is in countries which are already members of OPEC could also prove interesting. Currently, OPEC members set oil production quotas in order to gain monopoly rents in the global oil market. If these countries were to also coordinate natural gas supply decisions, such behavior could establish a link between natural gas and crude oil prices. Moreover, that link need not be what is observed today, although this again would require the effective elimination of either gas-fired or oil-fired electricity generation capacity (depending on which fuel would then be priced out of the electricity market). The ability of OPEC producers to effectively coordinate depends on the availability of supply outside these countries and the elasticity of demand for natural gas. Thus, while the likelihood of cartelization in natural gas is supported by the concentration of resource globally, the ability of consumers to switch to alternative fuel sources in large quantities (through the construction of a clean coal power plant, for example) could limit the long-term effectiveness of a natural gas cartel. Nevertheless, cartelization should be considered as a potential future feature to global gas markets.

Another factor that could potentially alter the long run relationship between natural gas and oil is the adoption of a tax on carbon. For example, a carbon tax would penalize petroleum more heavily than natural gas. For a power producer, this would alter the cost of generating electricity in favor of natural gas, effectively raising the marginal cost of using the petroleum products with which natural gas competes. This could permanently raise natural gas prices relative to oil prices since the fuels compete on a cost basis in the electricity sector. It would act somewhat like the changes in heat rates that lowered the relative cost of using natural gas to generate electricity. Thus, the equilibrium relationship between natural gas and crude oil prices could be shifted so that the gas-oil ratio was higher.

Factors that could alter the supply side influences on the gas-oil pricing relationship include a ban on gas flaring[6] and subsidies to gas production in various countries. While the ban on gas flaring might change wellhead economics, it cannot have an effect on the long run relationship between oil and gas prices if it does not fundamentally change fuel competition in the electricity sector. If such a policy were to encourage the development of infrastructure to move more associated gas to market, then the increased supply would lower prices. However, this would discourage production in other regions and at the same time encourage natural gas demand, especially for electricity generation. Alternatively, if the infrastructure costs were prohibitive, then a ban on natural gas flaring could actually result in curtailed oil production, as field operators were forced to either find means of sequestering the natural gas or simply reduce wellhead deliverability of oil until some method of methane capture could be implemented. This, however, would raise oil prices and again encourage natural gas demand.

Similarly, if a country were to subsidize natural gas production, it is unlikely that this would have any impact on the long run relationship between natural gas and crude oil prices. Any short run disequilibrium would result in demand-side response and altered investment opportunities that would eventually erode the dislocation of values between crude oil and natural gas.

VII. Concluding remarks

The long-term relationship between crude oil and natural gas will be driven by arbitrage and investment. If the gas price is below its long run relationship with the crude oil price, this should encourage demand through fuel switching and discourage supply, where it can, in the near term. If the price of natural gas is relatively low because,

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[6] In this connection, it might be useful to note that concern about climate change could actually favor gas flaring by reducing methane venting. The reason is that methane is a far more potent greenhouse gas than carbon dioxide. Hence, a tax on greenhouse gases should penalize methane emissions more than CO_2, one of the by-products of flaring.

perhaps, supply is available in abundantly inexpensive quantities, then demand should continue to grow, through displacement of oil/coal/etc., until we are driven to a point on the natural gas supply curve where there is some fuel price parity (adjusted for costs) again. Investments in gas-fired generation capacity and expansion of the industrial demand base would accomplish this. This result follows from trade theory.

On the other hand, demand-side and supply-side factors, as well as market arrangement and geopolitics, are all likely to influence the short run relationship between crude oil prices and natural gas prices. In addition, none of these influences is necessarily independent of the others. For example, contract terms will be shaped by perceived values of natural gas. Once established, contract terms will define parameters for development of future supply projects, which, in turn, reinforces the relationship so established. Unrealized value will also shape future negotiations, likely resulting in increased destination flexibility. This will serve to tie regional natural gas markets more closely together and demand-side factors in one region will increasingly influence the pricing relationship in other regions. All together, if the analysis for the United States serves as a guide, this points to a long-term stable relationship between crude oil prices and natural gas prices until a time when natural gas and oil products no longer compete in the electricity generation sector anywhere in the world. Certainly there will be forces that influence short run dynamic adjustments of natural gas prices, but those forces seem unlikely to be able to alter the long run relationship established by fundamental forces. Rather, the long-term price relationship is most likely to be altered only through a major change in market structure through regulation or tax of carbon or other exogenous policy or technological shifts that alter the relative costs of generating electricity using either natural gas or oil products.

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