The Majors' Shift to Natural Gas

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Preface

The Majors' Shift to Natural Gas investigates the factors that have guided the United States' major energy producers' growth in U.S. natural gas production relative to oil production. The analysis draws heavily on financial and operating data from the Energy Information Administration's Financial Reporting System (FRS). Pursuant to Section 205(h) of the Department of Energy Organization Act, which established the FRS, the Energy Information Administration, through its Form EIA-28, collects financial information and other measures of energy-related business efforts and results for major energy companies. Since the FRS data are collected on a uniform, segmented basis, the comparability of information across energy lines of business is unique to this reporting system. In 1999, 32 companies filed Form EIA-28. The information in this report is intended for use by the U.S. Congress, Government agencies, industry analysts, and the general public.

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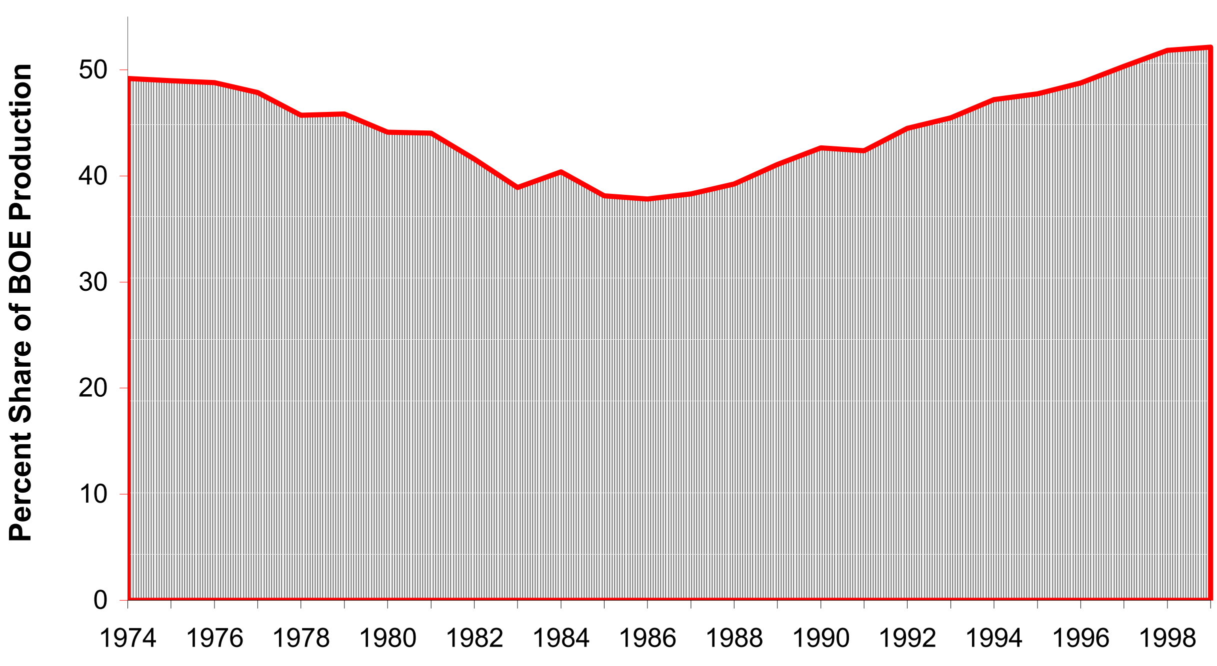
Introduction and Summary

Interest in natural gas has increased steadily in the last decade or so. The clean-burning properties of natural gas compared to other fossil fuels together with increasing concerns about air quality have attracted environmental interests. The full deregulation of U.S. natural gas markets in the early 1990's and increased globalization of natural gas trade in recent years have attracted the interests of investors. Increased volatility of natural gas prices, including recent unprecedented price spikes, has raised concerns about this fuel in households and businesses alike.

Major U.S.-based energy producers have shown a growing interest in natural gas as well. For the purposes of this report, the "majors" are the companies that report to the Energy Information Administration's (EIA's) Financial Reporting System (FRS)[Note 1]. Natural gas has become an increasingly important target of investment for the majors. The clearest evidence of heightened interest is the shift in the composition of natural gas production relative to oil production. Figure 1 shows the share of natural gas in the majors' combined oil and natural gas production in the United States (natural gas measured in barrels of oil equivalent (BOE)).[Note 2] The shift to natural gas began in the mid-1980's and continued on an upward trend thereafter. In 1999, natural gas accounted for 52 percent of the majors' U.S. oil and natural gas production. Prior to the mid-1980's, the natural gas share was on a steady downward trend. This path was surprisingly smooth in spite of the regulatory changes and turmoil affecting U.S. natural gas markets over the past 25 years.[Note 3]

Figure 1. Natural Gas Share of U.S. Oil and Natural Gas Production for FRS Companies, 1974-1999



Note: BOE= barrels of oil equivalent. Natural gas converted at 1 mcf= 0.178 barrels
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

The majors' shift to natural gas production has not been confined to the United States. Figure 2 shows that the natural gas share of the majors' production rose more sharply in Canada than in the United States over the last 15 years or so. Outside North America, the shift to natural gas paralleled the shift in the United States. All regions showed an increase in the share of natural gas in the majors' combined oil and natural gas production (Figure 3).

The focus of this report is on the United States. This report reviews some of the factors that underlie the majors' shift to natural gas in the United States. Key findings include:

- Growth in the majors' U.S. natural gas reserve base came primarily from the companies' own exploration and development efforts. Mergers and acquisitions played a relatively small role.

- The profit margin on the majors' U.S. natural gas production, as measured by the difference between prices received and the full costs of production, has generally increased relative to the profit margin on oil production, beginning in the early 1980's.

- A decline in natural gas production costs relative to oil prices as well as a general rise in natural gas prices relative to oil prices were important in the growth of natural gas margins relative to oil margins.

- The majors responded to the differential in profitability by shifting their U.S. upstream production toward natural gas.

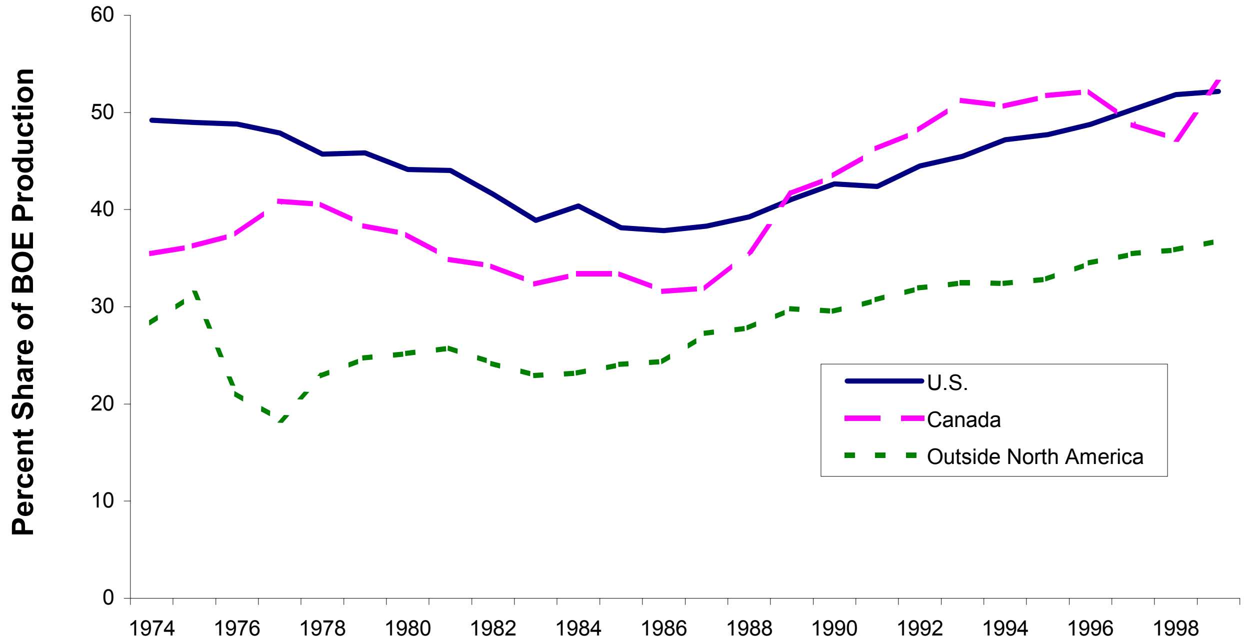
- In the 1990's, the availability of tax credits for non-conventional fuels production (mostly coalbed methane) under Section 29 of the Windfall Profit Tax Act appeared responsible for much of the growth in the majors' U.S. natural gas production.

- A number of recent developments favor a larger role for the majors in U.S. natural gas supply in the future. These developments include the majors' future growth in Canadian natural gas production, prospects for coalbed methane production, the possibility of an Alaskan natural gas pipeline, and the majors' growing role in liquefied natural gas (LNG) trade.

- EIA's short-term oil and natural gas price forecasts for 2001 and longer term forecasts of natural gas demand suggest a continued shift to natural gas.

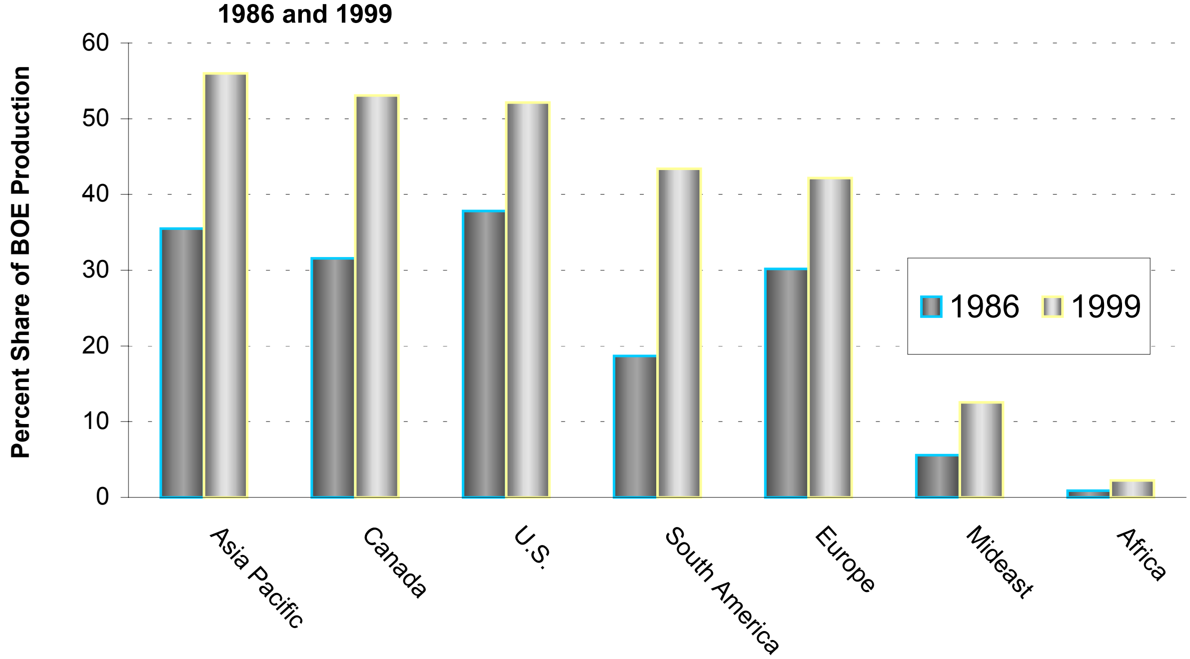
This analysis draws on data from the EIA's Financial Reporting System (FRS) and the EIA's annual *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves* report. The FRS is an annual survey that collects, through Form EIA-28, financial and operating information from U.S.-based major energy producing companies. The selection criteria for a U.S.-based company to be designated as a major require ownership of 1 percent or more of U.S. production or reserves of oil or natural gas or 1 percent or more of U.S. refinery capacity or refined product sales. The list of companies reporting to the FRS is in Table A1 of the Appendix. The data are reported by lines of business, including U.S. and foreign oil and natural gas production. Expenditures for exploration, development, and production are reported separately for U.S. onshore and offshore and seven foreign regions as are reserves and production data.

Figure 2. Natural Gas Share of Oil and Natural Gas Production by Region for FRS Companies, 1974-1999



Note: BOE= barrels of oil equivalent. Natural gas converted at 1 mcf= 0.178 barrels
Source :Energy Information Administration, Form EIA-28 (Financial Reporting System).

Figure 3. Natural Gas Share of BOE Production by Region for FRS Companies, 1986 and 1999



Note: BOE= barrels of oil equivalent. Natural gas converted at 1 mcf= 0.178 barrels. The Former Soviet Union (FSU) region is not shown because data for this region were not collected before 1992.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Growth in the Majors' U.S. Natural Gas Production

For the FRS group of companies, U.S. production of natural gas rose from a low of 7.1 Trillion cubic feet (Tcf) in 1986 to a peak of 8.4 Tcf in 1998 and fell to 8.0 Tcf in 1999. Table 1 shows the sources of growth in the reserve base since the beginning of 1986 that underlie this growth in production. The bulk of the growth in the FRS companies' U.S. natural gas reserve base came through the drill bit. Reserves added through extensions, discoveries, revisions, and improved recovery totaled 95.6 Tcf and far exceeded the 25.3 Tcf gained through mergers and acquisitions. Offsetting the additions to reserves were production and sales of producing properties. In fact, on balance, the majors' U.S. natural gas reserves declined by 15 percent between the beginning of 1986 and the end of 1999.

How did the majors increase their natural gas production in the face of a declining reserve base? Increased rates of extraction contributed to the growth in production despite an overall decline in the reserve base (Figure 4). Onshore and offshore locales both exhibited upward trends in extraction rates. In the context of reserve accounting, increased rates of extraction accounted for about 30 percent of the growth in the majors' U.S. natural gas production over the 1986 to 1999 period. Reserves added through exploration and development activity accounted for slightly over 70 percent, while the net of acquisitions, divestitures, and entry (of companies into the FRS reporting group) equaled a negative 1 percent of the majors' growth in U.S. natural gas production.[Note 4]

Table 1. U.S. Natural Gas Reserves and Reserve Changes for FRS Companies, 1986-1999

(Trillion cubic feet)	
Beginning Reserves, 1986	83.7
Reserve Additions, 1986-1999	95.6
Purchases, 1986-1999	25.3
Production, 1986-1999	-109
Sales, 1986-1999	-31.2
Entry & Exit, net	6.6
Ending Reserves, 1999	70.9

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System)

An Important Role for Section 29 Tax Credits

Tax credits appear to have played an important role in the majors' growth in U.S. natural gas production. In particular, nearly half of the FRS companies reported[Note 5] reductions in their Federal income tax expense from credits available under Section 29 of the Windfall Profit Tax Act ("Section 29"). Section 29 allows a nonrefundable tax credit for domestic production of qualifying fuels. The qualifying fuels are:

- Oil from shale and tar sands
- Gas from coal seams, tight sands, shale, geopressurized brine, Devonian shales, biomass
- Synthetics from oil
- Qualifying wood fuels

- Steam from solid agricultural products.

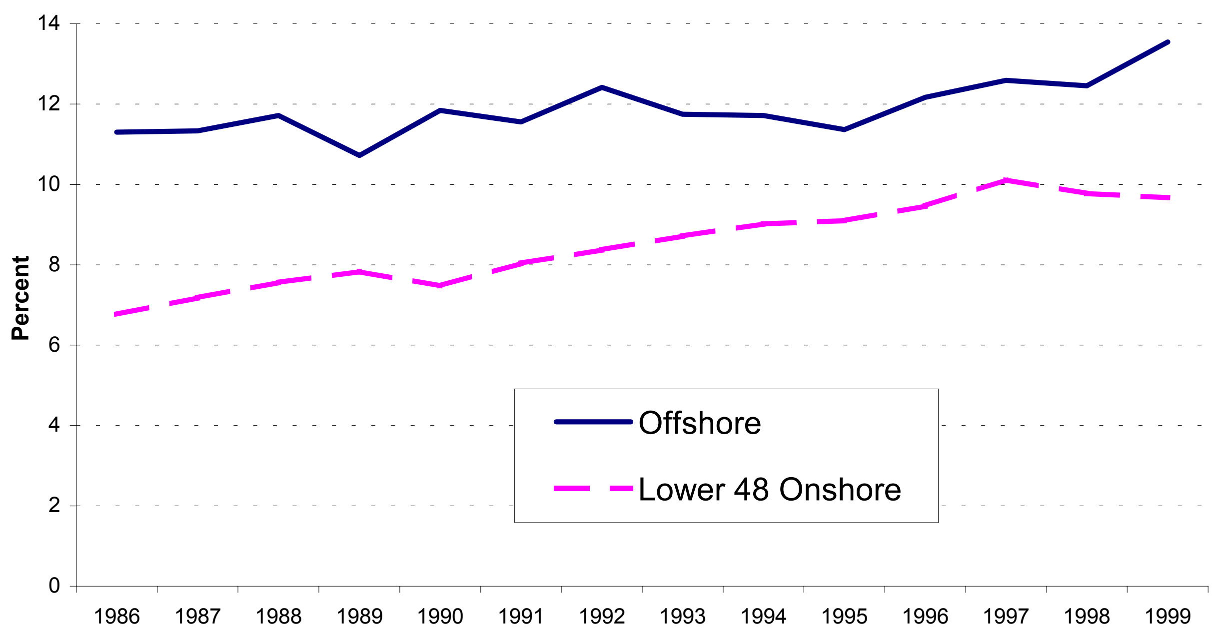
The credit applies to qualifying fuels produced from wells drilled between 1980 and December 31, 1992. The credit is scheduled to expire at the end of 2002.

The value of the Section 29 credit is determined by a formula which varies with the price of oil and inflation.[Note 6] The full value of the credit has ranged from $0.90 per thousand cubic feet (mcf) of natural gas to $1.08 during the 1990's. The credit averaged $1.02 per mcf for the decade and added 53 percent to the effective price received for eligible production based on the U.S. wellhead price (Figure 5).

Most of the FRS companies that generated Section 29 credits did so by producing natural gas from coal seams (generally termed, coalbed methane). Based on an analysis of FRS companies' public information, all but two of the companies that reported receiving Section 29 credits were involved in coalbed methane production. The two other companies received Section 29 credits for production from tight natural gas formations.

Coalbed methane production has been a major source of growth in U.S. natural gas production in the 1990's. Between 1990 and 1999, growth in coalbed methane production equaled 57 percent of the overall growth in U.S. natural gas production.[Note 7]

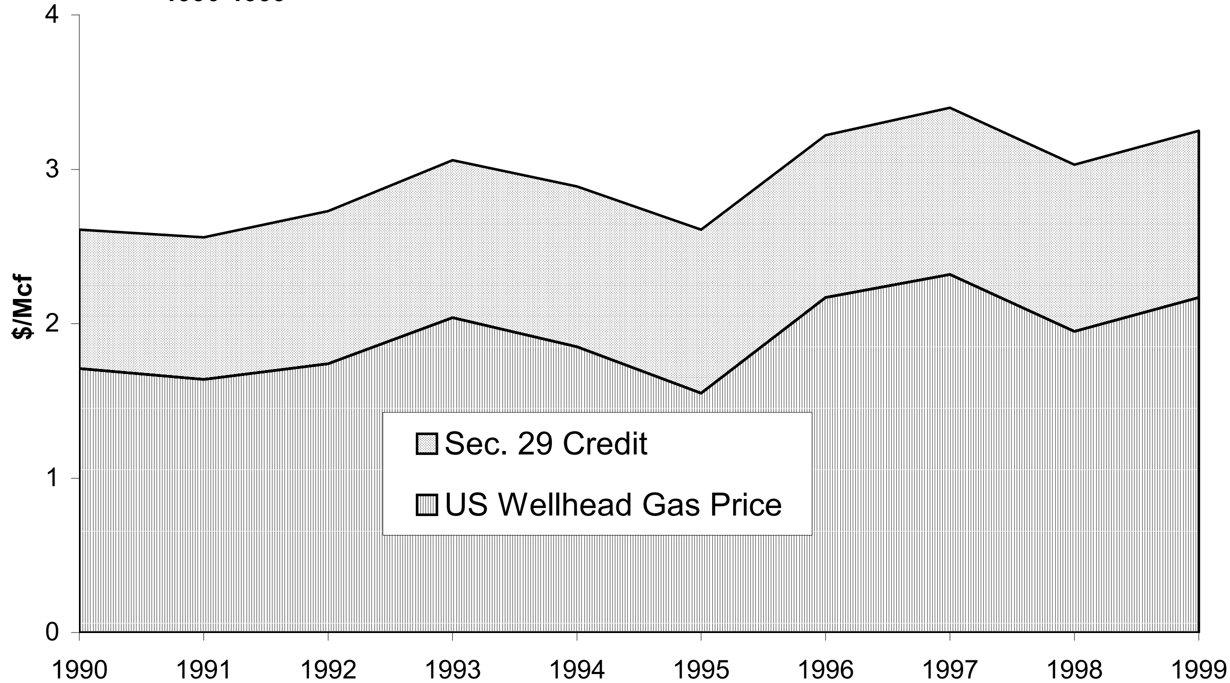
Figure 4. U.S. Natural Gas Extraction Rates for FRS Companies, 1986-1999



Note: Extraction rate = production / (end-of-period reserves + production)
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

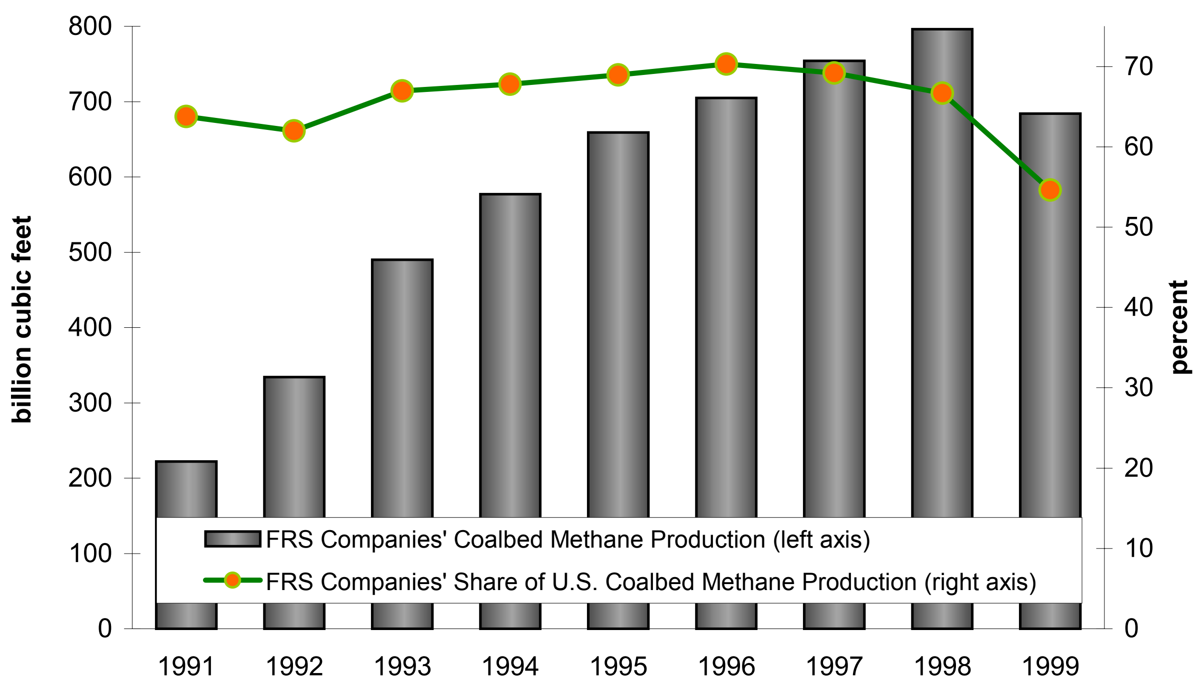
FRS companies have been prominent in the growth of coalbed methane production, accounting for about two-thirds of U.S. coalbed methane production in the 1990's (Figure 6). However, only a minority of the FRS companies have been involved in coalbed methane production. What led some majors to pursue this non-conventional source of natural gas production while other majors focused on more familiar sources? Most of the coalbed methane in the United States is extracted from deposits in Rocky Mountain

Figure 5. Section 29 Credit for Coalbed Methane and U.S. Wellhead Price of Natural Gas, 1990-1999



Source: U.S. wellhead natural gas price: EIA, *Natural Gas Monthly*

gure 6. U.S. Coalbed Methane Production for FRS Companies, 1991-1999



Source: Special compilation from Form EIA-23 (Annual Survey of Domestic Oil and Gas Reserves) by the Reseves and Production Division, Office of Oil and Gas, Energy Information Administration states (see Figure 7 entitled, "U.S. Lower-48 Coalbed Methane Basins"). A characteristic common to all of the FRS companies involved in coalbed methane production was significant ownership of coal reserves in the western United States in the first half of the 1980's. A company that is familiar with the geology of coal deposits in this area and owns mineral rights to these deposits would likely have a cost advantage in the development of coalbed methane. However, ownership of western coal reserves was not sufficient to make coalbed methane development attractive to every major: six surviving majors that owned western coal reserves in the 1980's never ventured into coalbed methane production.

The incentives provided by Section 29 credits played a key role in the majors' shift to natural gas in the 1990's. Figure 8 shows that the FRS companies receiving Section 29 tax credits ("Section 29 companies") were responsible for the growth in the majors' U.S. natural gas production in the 1990's (prior to 1990, coalbed methane production was negligible). Between 1990 and 1999, the Section 29 companies increased their U.S. natural gas production by 26 percent, while other majors reduced their production by 14 percent.

The contrast in natural gas-related resource development activity between the companies was even more dramatic than production growth. The FRS companies that reported receiving Section 29 tax credits, overall, quadrupled their rate of onshore natural gas drilling between 1986 and 1990, from slightly under 400 natural gas well completions per year to about 1,600 (Figure 9). This surge in drilling activity undoubtedly was related to the originally legislated deadline of December 31, 1990, when production from wells initiated after that date would not qualify for Section 29 credits. Congress extended the deadline to December 31, 1992. In contrast, other FRS natural gas producers increased their onshore natural gas drilling activity by less than 200 well completions over the same period. After 1990, the natural gas drilling activity of the two groups of companies exhibited a roughly parallel pattern, with the Section 29 companies averaging over 900 more completions per year than the other majors. The persistently higher rate of onshore drilling largely reflects the costs and geologic characteristics of coalbed methane development. Coalbed methane development requires many more wells to achieve a given rate of production than do most other onshore natural gas fields, but at much lower rates of production per well and at much shallower depths (see the box entitled, "Coalbed Methane Basics").

The downturn in natural gas drilling in 1998-1999 shown in Figure 9 was a response to the earlier decline in U.S. natural gas prices at the wellhead. The average monthly wellhead price fell from $3.40 per thousand cubic feet at the beginning of 1997 to a low of $1.68 in March 1999.[Note 8] Also, in 1999, nearly all of the FRS companies reduced their capital expenditures for oil and gas production. This cutback in spending was part of a larger effort to repair the damage done to their balance sheets in 1998. [Note 9]

The Main Driver: Profitability Differences

Do the effects of Section 29 alone account for the majors' shift to natural gas? The strong difference in the paths of natural gas production between the Section 29 companies and other companies shown in Figure 8 appears to provide convincing evidence that this is the case. However, Section 29 credits apply only to U.S. production and, consequently, cannot account for the majors' shift to natural gas in their upstream production outside the United States (Figures 2 and 3). The effects of Section 29 cannot account for the majors' shift to natural gas in the late 1980's, since Section 29 credits received by the majors were nil before 1989. Their earlier flight from natural gas in the 1970's and early 1980's

(Figure 1) was unrelated to Section 29 credits since the credits were not available until the early 1980's. Also, although a majority of the FRS companies did not opt to shift their investment strategies to gain Section 29 credits, these companies nevertheless continued to shift to natural gas in their U.S. upstream production, albeit at a less rapid pace than the companies receiving Section 29 credits ("Section 29 companies") (Figure 10). Thus, although Section 29 has provided an important incentive for development of U.S. natural gas reserves in the 1990's, additional factors underlie the majors' long-running shift to natural gas.

Figure 7. U.S. Lower 48 Coalbed Methane Basins

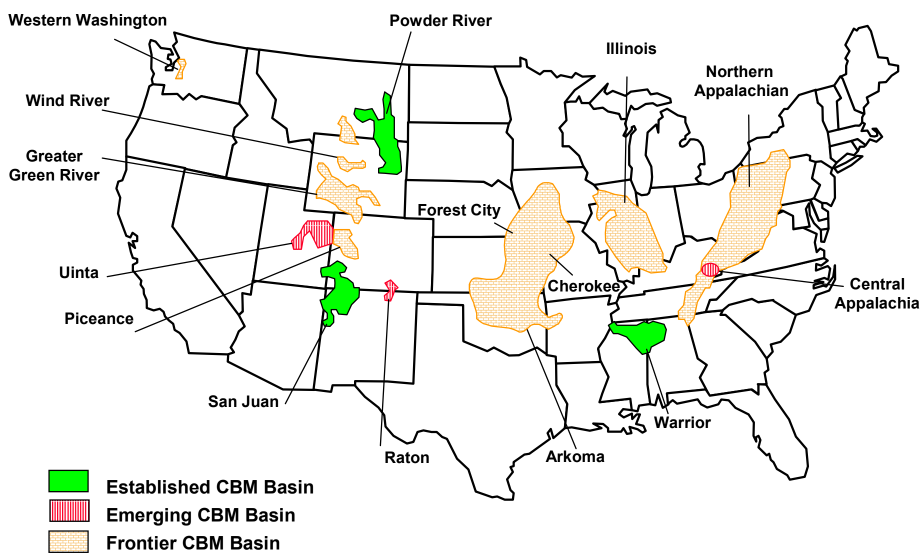
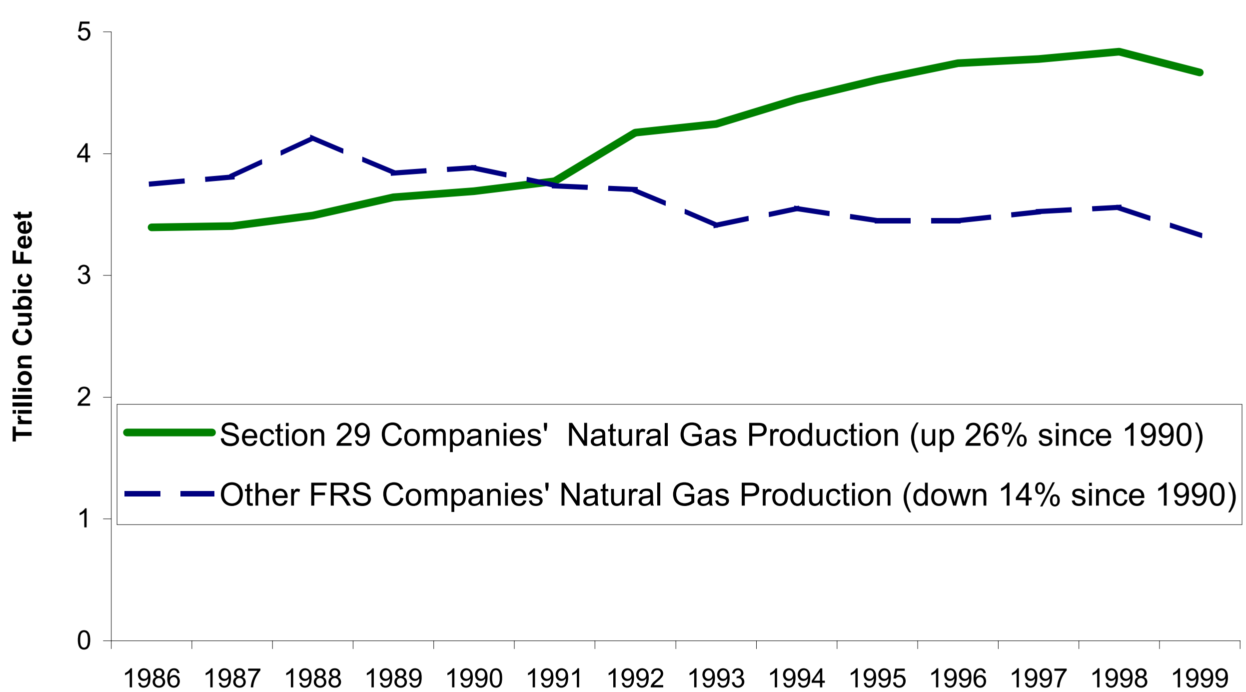
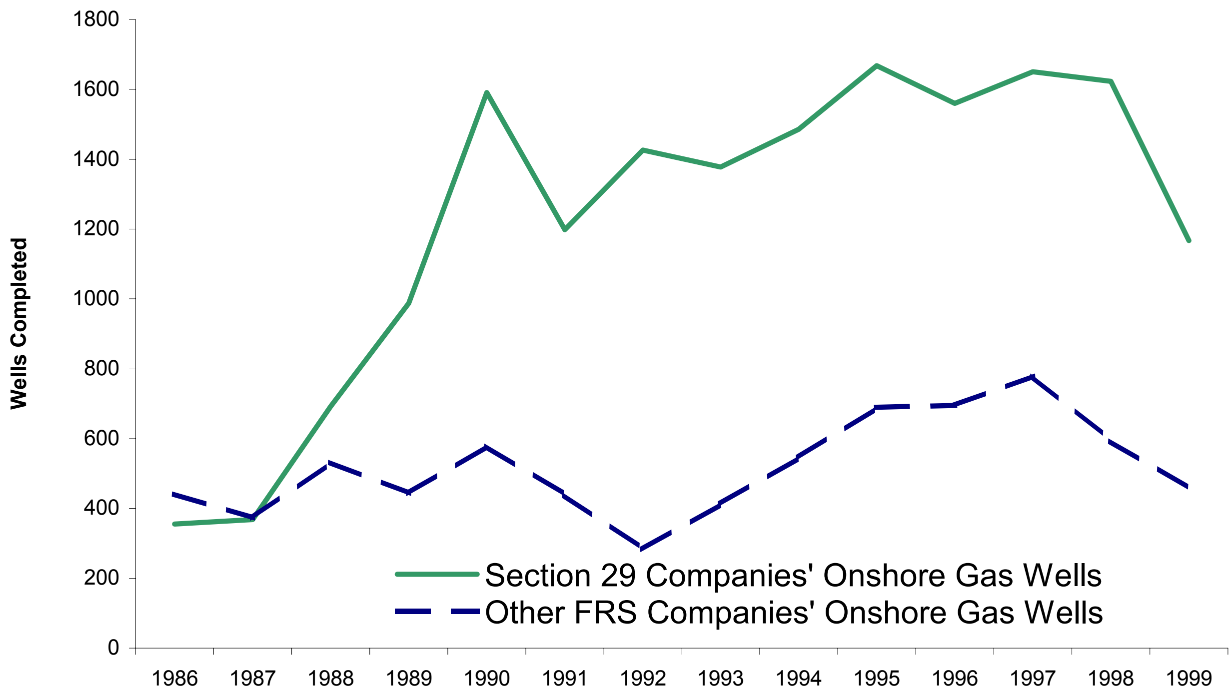


Figure 8. U.S. Gas Production for FRS Companies, 1986-1999



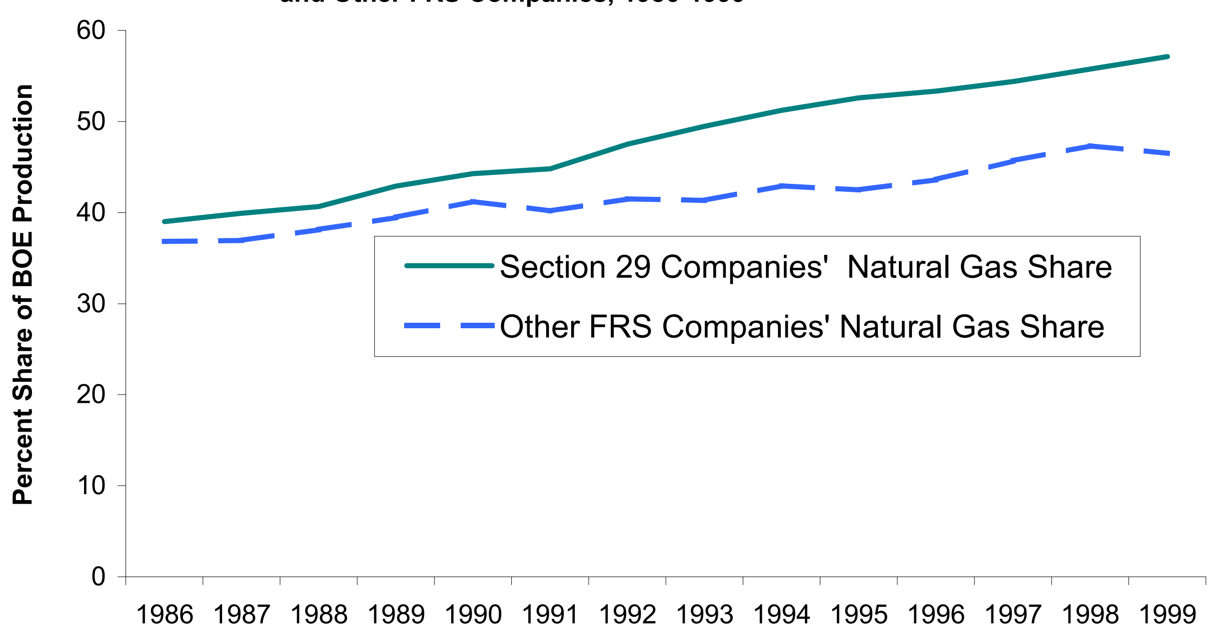
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Figure 9. U.S. Onshore Gas Wells Completed by FRS Companies, 1986-1999



Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Figure 10. Natural Gas Share of U.S. Oil and Natural Gas Production for Section 29 and Other FRS Companies, 1986-1999



Note: BOE= barrels of oil equivalent. Natural gas converted at 1 mcf= 0.178 barrels
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Coalbed Methane Basics

Coalbed Methane (CBM) is methane extracted from coal beds. In a conventional oil or gas reservoir, production is from oil or gas located above a water contact. CBM production is different. Water completely permeates coal beds, and its pressure causes the methane to be adsorbed onto the grain surfaces of the coal. To produce CBM, the water must be drawn off first, lowering the pressure so that the methane will desorb from the coal and then flow to the well bore.

CBM production is attractive due to several geological factors. Coal stores six or seven times as much gas as a conventional natural gas reservoir of equal rock volume due to the large internal surface area of coal. Much coal is accessible at shallow depths, making well drilling and completion inexpensive. Finding costs are also low since methane occurs in coal deposits, and the location of the Nation's coal resources is well known.

CBM production was initially spurred by a tax incentive. Internal Revenue Code Section 29 provides a non-refundable tax credit for sale of CBM (as well as other qualified alternative fuels) from wells drilled between 1980 and 1992 inclusive, for sales of fuel between 1980 and 2002 inclusive.

1.3 trillion cubic feet (Tcf) of CBM was produced in 1999, representing 6.7 percent of the 18.6 Tcf of U.S. dry gas production. There were 13.2 Tcf of CBM reserves in 1999, representing 7.9 percent of the 167.4 Tcf of dry gas proved reserves. Undeveloped resources of CBM have been estimated at 60 Tcf.

New Mexico, Colorado, and Alabama hold 75 percent of proved coalbed reserves (see Figure 7 entitled, "U.S. Lower 48 Coalbed Methane Basins"). Emerging CBM areas are located in Appalachia and the Rocky Mountain region.

CBM production entails both environmental benefits and concerns. Air quality benefits arise from (1) substituting clean-burning methane for dirtier fuels and (2) the burning, rather than venting into the atmosphere, of coalbed methane released as a result of coal mining activities (methane is 21 times more potent a greenhouse gas than is CO2). However, disposal of the large volumes of water that are produced from CBM wells, in a way that is environmentally acceptable and yet economically feasible, is a concern. Depending on the characteristics of the site and the chemistry of the produced water, it may be reinjected into the subsurface, dispersed on the surface, pumped into evaporation ponds, or released directly into local streams.

Profitability and Margins

A venerable proposition in the field of economics is that capital will tend to flow to activities with higher expected rates of return, and conversely, will tend to be withdrawn from activities with lower rates of return. This proposition is of sufficient generality that it should apply to the majors' shift to natural gas in their U.S. upstream operations.

The profitability of a business for a given period of time, a year for example, is often calculated by the income gained during the period divided by the book value of the assets (net of depreciation) employed during the period. EIA's Financial Reporting System annually presents rates of return for U.S. oil and natural gas production, as well as other energy lines of business and nonenergy businesses, based on data collected from major energy companies through Form EIA-28. Since nearly all oil and natural gas companies produce both oil and natural gas, rather than only oil or only natural gas, separate reporting of income and associated assets for only oil production or only natural gas production is rare. Consequently, a surrogate measure of profitability that can be estimated for oil and natural gas separately is necessary.

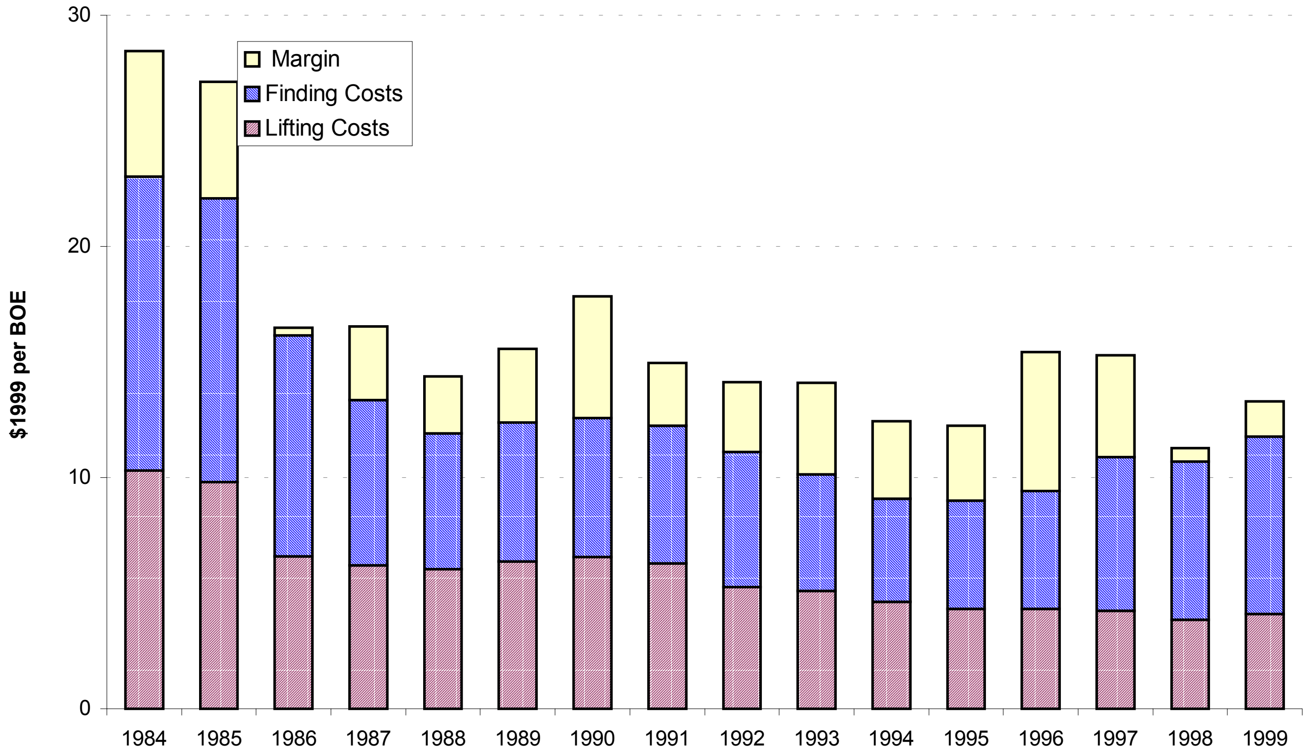
A good candidate for a profitability surrogate is the upstream margin. The upstream margin is defined as the price received at the wellhead for oil and natural gas produced less the costs of extracting oil and natural gas (termed, lifting costs) less the costs of replacing the oil and natural gas produced (termed, finding costs). If the upstream margin is positive, then the wellhead price covers both production costs and the costs of replacing production as well as providing a positive return to current investments. If the margin is negative, then the costs of replacing production are not being fully covered. Companies in this latter position will have an incentive to reduce their reserve base and their production will tend to decline. In the dire situation when the wellhead price is below lifting costs, out-of-pocket expenses are not being covered and cessation of production becomes a possibility. Figure 11 shows the upstream margin, finding costs, and lifting costs (in $1999 per barrel of oil equivalent (BOE)) for the majors' U.S. oil and natural gas production operations.

All of the components of the upstream margin for oil and natural gas can be derived from aggregate FRS data. Wellhead prices are simply revenue received divided by production sold. Lifting costs are the costs, per barrel of oil and natural gas, of operating and maintaining wells and related equipment and facilities, including taxes levied directly on production such as state severance taxes. Finding costs (which exclude oil and natural gas reserves gained through mergers, acquisitions, and purchases of properties with proven reserves) ideally would be measured, for a given time period, by expenditures for oil and natural gas exploration and development and the oil and natural gas reserve additions that resulted from these expenditures. However, an exact association between a dollar of expenditure and reserve additions is elusive because of lags between expenditures and activity (e.g., drilling) and lags between activity and reserve additions. In practice, in order to mitigate the effects of leads and lags, finding costs are calculated by the ratio of exploration and development expenditures for a given interval of time to oil and natural gas reserves added in barrels of oil equivalent for the same interval of time. Generally, EIA publications have used a 3-year interval for calculating finding costs.

The upstream margin for the majors' U.S. oil and natural gas production operations tends to correlate positively with the upstream rate of return. Figure 12 shows a scatter diagram between these two measures from 1984 on, with a correlation coefficient of 0.78. The two measures are not correlated in the earlier years of FRS data collection.

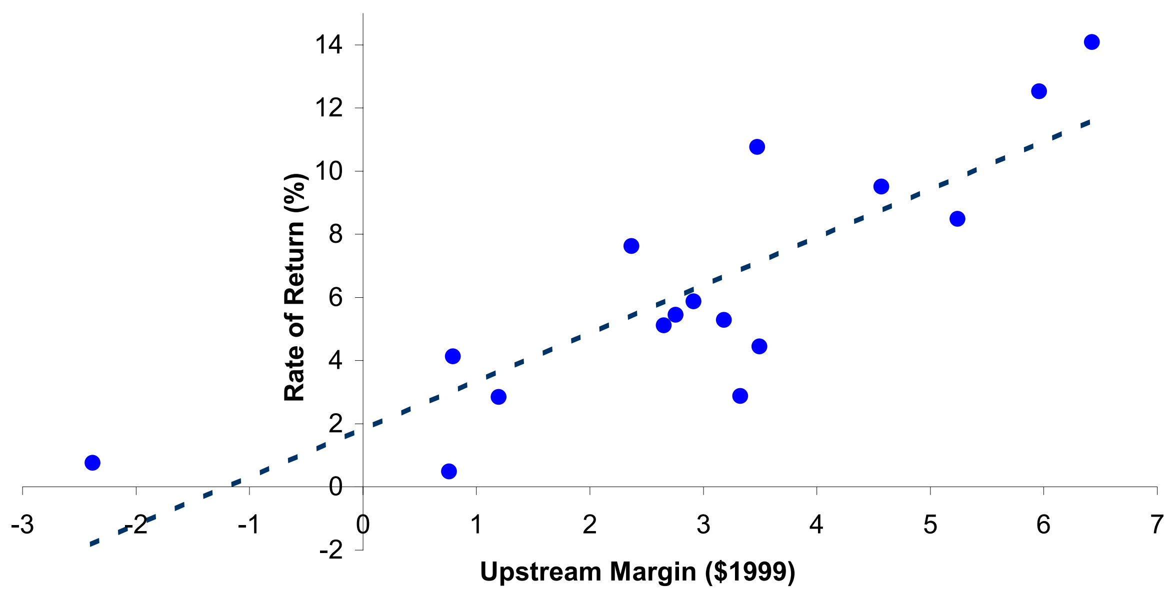
There appear to be at least two reasons for this lack of expected correlation in the 1978 to 1983 period. First, several of the companies made massive downward revisions of their U.S. oil and natural gas reserves in the late 1970's. For example, in 1979, six companies revised their U.S. reserves down by a total of 1 billion BOE, equal to 7 percent of their U.S. oil and natural gas reserves. The effect of these writedowns was to greatly increase calculated finding costs beyond values that were representative of actual resource development performance. Second, in the late 1970's and early 1980's, financial accounting standards for oil and natural gas producers underwent substantial and innovative changes led by the U.S. Securities and Exchange Commission (SEC) and the Financial Accounting Standards Board (FASB). The revisions especially targeted companies' disclosures of oil and natural gas reserves, in both financial and physical aspects. These are the same data elements that are utilized in the calculation of finding costs. Since the SEC and FASB required implementation of the standards for the companies' 1982 fiscal year, finding cost calculations based on data prior to 1982 will be subject to the problems that the accounting revisions were designed to correct. Consequently, the upstream margin for the years 1978 to 1981 was negative or nearly so although the profitability of U.S. oil and natural gas production was at historically high levels.

Figure 11. Costs and Margins in U.S. Oil and Gas Production for FRS Companies, 1984-1999



Note: BOE= barrels of oil equivalent. Natural gas converted at 1 mcf= 0.178 barrels
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Figure 12. Rate of Return vs. Upstream Margin ($1999), 1984-1999

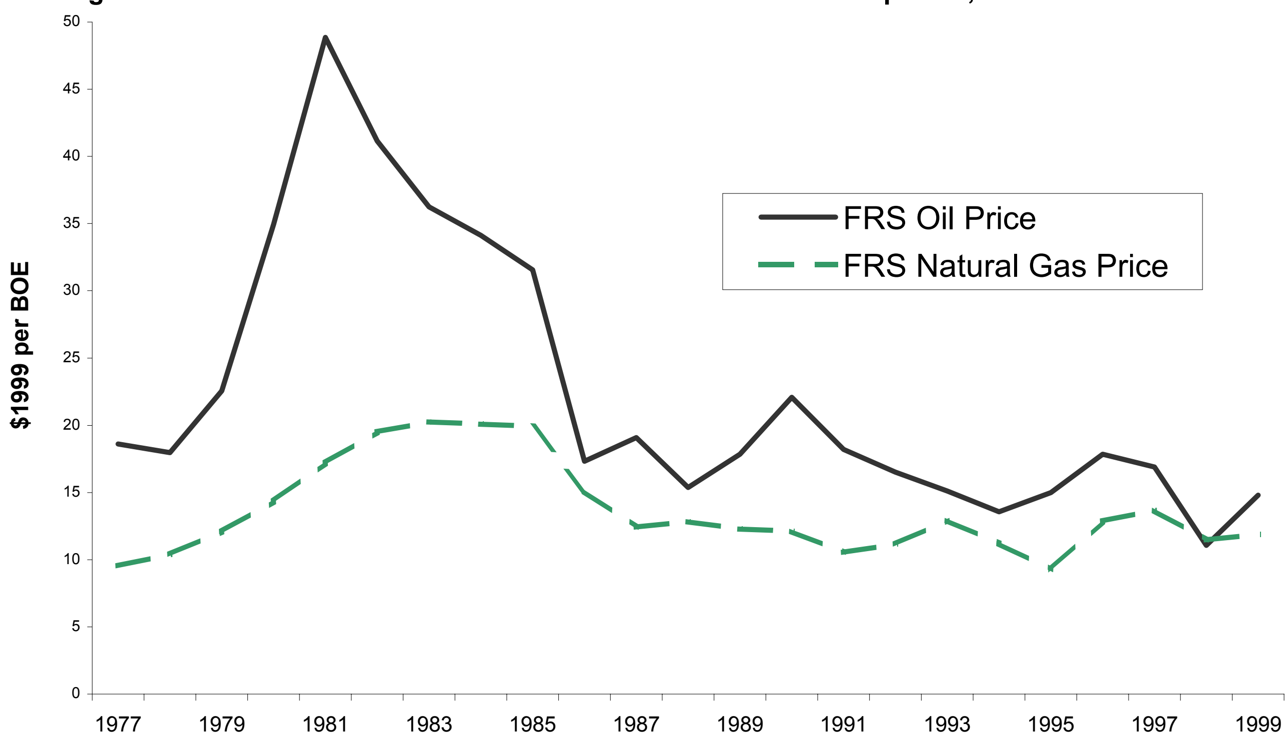


Note: Rate of Return = net income contribution / (net property, plant, and equipment + investments and advances)
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

The Calculation of Oil and Natural Gas Margins

In order to obtain upstream margins for oil and natural gas production separately, revenues and costs need to be separated. Oil and natural gas revenues are easily separated in the FRS data. The FRS annually collects upstream revenues and associated sales volumes for oil and natural gas separately. Figure 13 shows the average annual FRS wellhead prices for oil and natural gas in constant 1999 dollars per barrel of oil equivalent.

Figure 13. U.S. Wellhead Oil and Natural Gas Prices for FRS Companies, 1977-1999



Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Lifting costs are not so easily separated. Although oil and natural gas production are separately reported, companies report associated lifting costs only for total upstream operations. All FRS companies with U.S. upstream operations produce both oil and natural gas, with the companies' share of natural gas ranging from a high of 91 percent down to 11 percent in 1999. Consequently, a useful characterization of reported lifting costs is to assume that they are a weighted average of natural gas lifting costs and oil lifting costs with the weights being each fuel's share of total oil and natural gas production (in BOE). Formally,

(1) $L = s\,L_g + (1\text{-}s)L_o$

Where L = reported lifting costs per BOE of combined oil and natural gas production, s = natural gas share of total BOE production, L_g = lifting costs for natural gas per BOE of natural gas production, and L_o = lifting costs for oil per BOE of oil production.

The FRS companies annually report their overall lifting costs and oil and natural gas production broken down by U.S. onshore and U.S. offshore regions. Equation (1) was estimated for FRS companies for each of the years 1977 through 1999 by onshore and offshore regions.[Note 10] The estimates of oil and natural gas lifting costs in constant dollars are shown in Figures 14a and 14b. A few observations might be of interest. Oil lifting costs are higher than natural gas lifting costs both onshore and offshore, the only exceptions being 1986 and 1987 for onshore locales when companies made sharp cutbacks in production from high-cost oil wells following the oil price crash in 1986.[Note 11] Natural Gas wells generally require less support equipment such as pumps and motors because well pressure provides much more natural lift in natural gas wells than in oil wells, leading to lower operating, maintenance, and repair costs. Lifting costs for natural gas are generally lower offshore than onshore, but there is no statistically significant difference for oil lifting costs.[Note 12] Offshore producing fields tend to have larger reservoirs of oil and/or natural gas. As a previous EIA report noted, larger field sizes tend to have lower lifting costs.[Note 13]

The majors' shift to natural gas production began in the mid-1980's. Since that time, natural gas lifting costs have been on a downward trend both onshore and offshore. Between 1986 and 1999, onshore natural gas lifting costs declined by over $5 (in constant 1999 dollars) per BOE or about $0.90 per thousand cubic feet. The most recent peak in offshore natural gas lifting costs was in the 1988 to 1989 period. Since then, they have declined by about $2 per BOE. By contrast, the trend in oil lifting costs, since the mid-1980's, has been essentially flat, both onshore and offshore. Oil lifting costs have shown more variability offshore than onshore, with offshore costs showing a tendency to rise in recent years.

Separating the third component of the upstream margin, finding costs, by oil and natural gas is problematical. Estimates of equations for finding costs analogous to equation (1) indicated that either (a) there were rarely differences in the underlying oil and natural gas finding costs or (b) company-specific factors (not examined here) other than the natural gas share of total reserve additions can statistically explain differences in finding costs between FRS companies.[Note 14] In either case, estimation of finding costs for oil separate from natural gas does not appear feasible. Consequently, this report will not differentiate finding costs between oil and natural gas for purposes of calculating upstream margins for oil and natural gas separately. The FRS data do allow separate calculation of finding costs for onshore and offshore. Figure 15 shows that finding costs are generally higher for offshore locales.

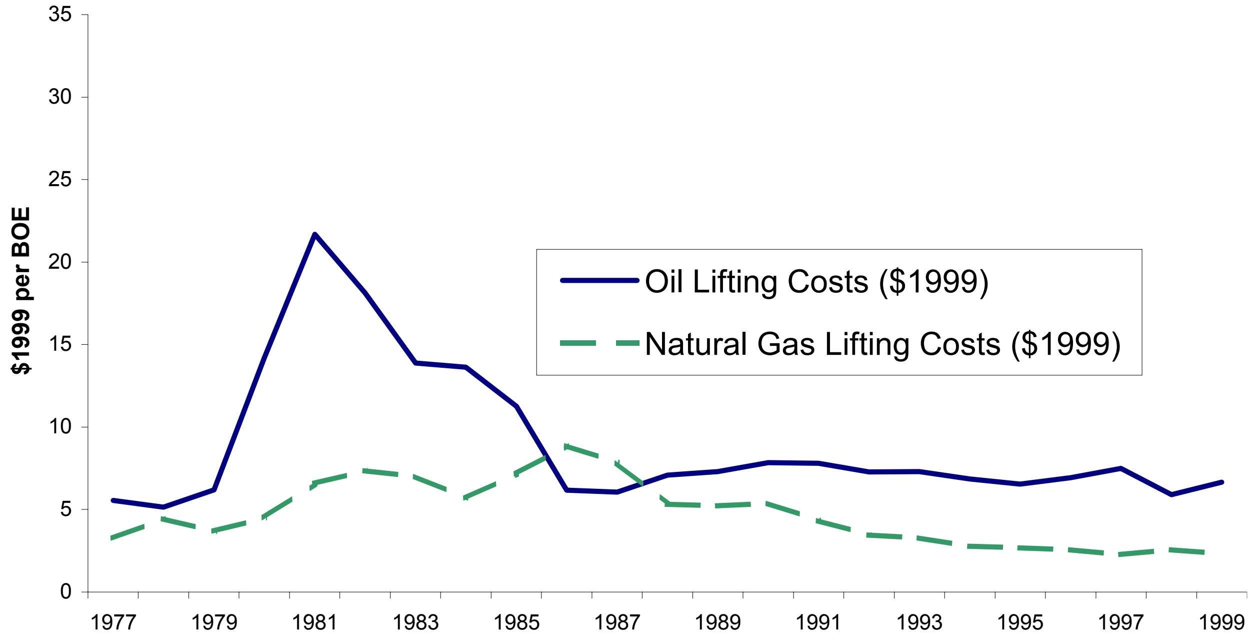
Oil vs. Natural Gas Margins: Findings

Beginning in 1986, when the shift to natural gas among the majors began, the margin on the major's U.S. natural gas production (wellhead price less lifting costs and finding costs) was slightly below zero (Figure 16). Thereafter, the natural gas margin generally rose and exceeded the margin on oil for the first time in 1993. By contrast, from 1986 on, the trend in the oil margin was flat up to 1996 and fell sharply after 1996. Between 1993 and 1999, the natural gas margin exceeded the oil margin in five of seven years.

The difference between the natural gas margin and the oil margin is a surrogate for the profitability of natural gas production relative to the profitability of oil production. Since investment targets tend to shift toward activities with higher expected rates of return, the natural gas share of production should be positively correlated with the difference between natural gas and oil margins.

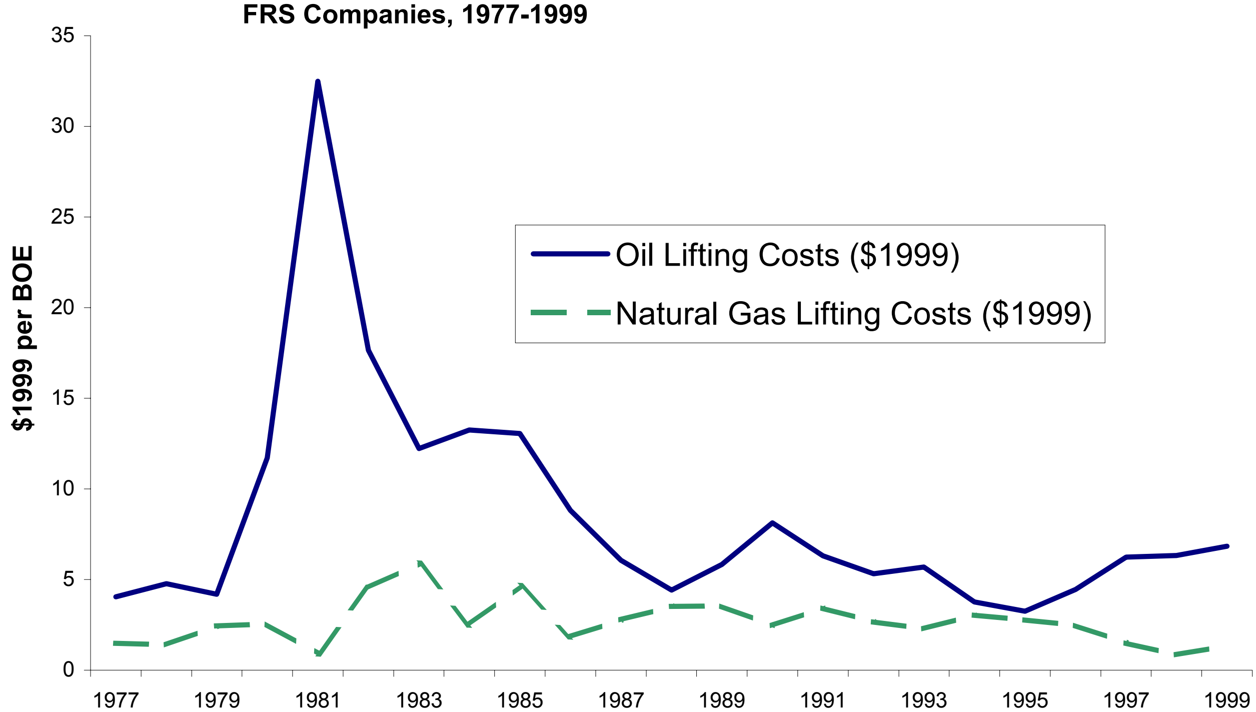
The difference in margins (natural gas minus oil) fell sharply between 1978 and 1981 (Figure 17). This was a period of sharp escalations in the price of oil. Although U.S. natural gas prices were also rising and the rise in lifting costs for oil outpaced natural gas lifting costs, the $30 per barrel rise ($1999) in oil prices swamped these offsetting effects. The majors shifted away from natural gas production and toward oil production in response to this drop in the profitability of natural gas relative to oil. The shift

Figure 14a. U.S. Onshore Lifting Costs (including production taxes) for FRS Companies, 1977-1999



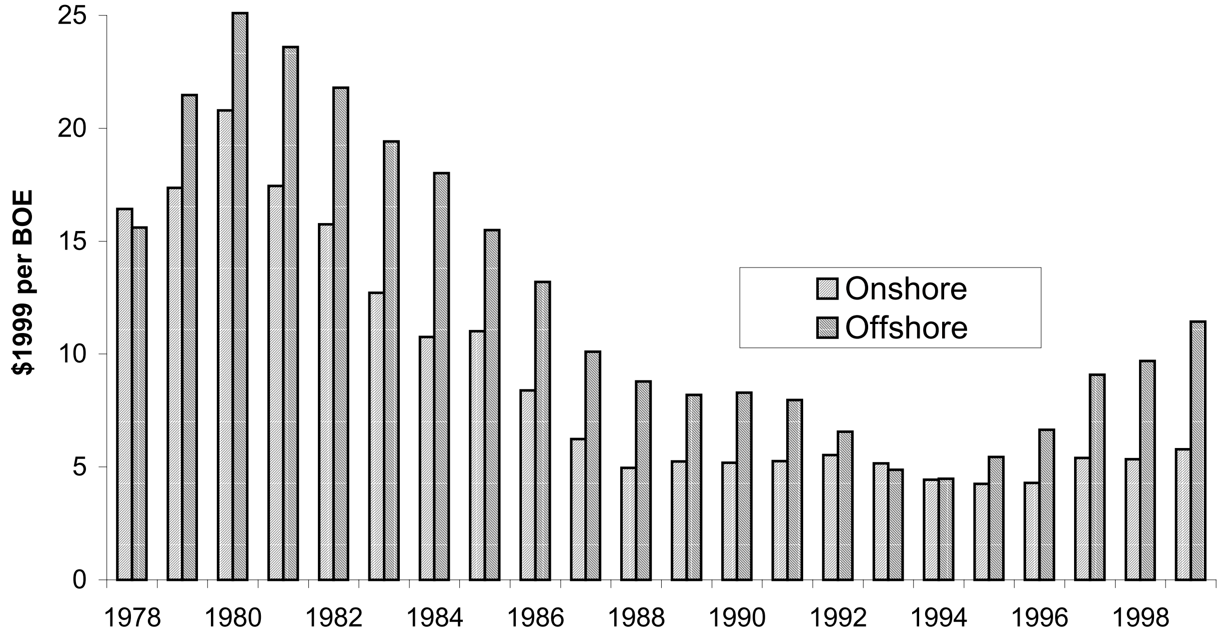
Note: BOE= barrels of oil equivalent. Natural gas converted at 1 mcf= 0.178 barrels
Source :Energy Information Administration, Form EIA-28 (Financial Reporting System).

Figure 14b. U.S. Offshore Lifting Costs (including production taxes) for FRS Companies, 1977-1999



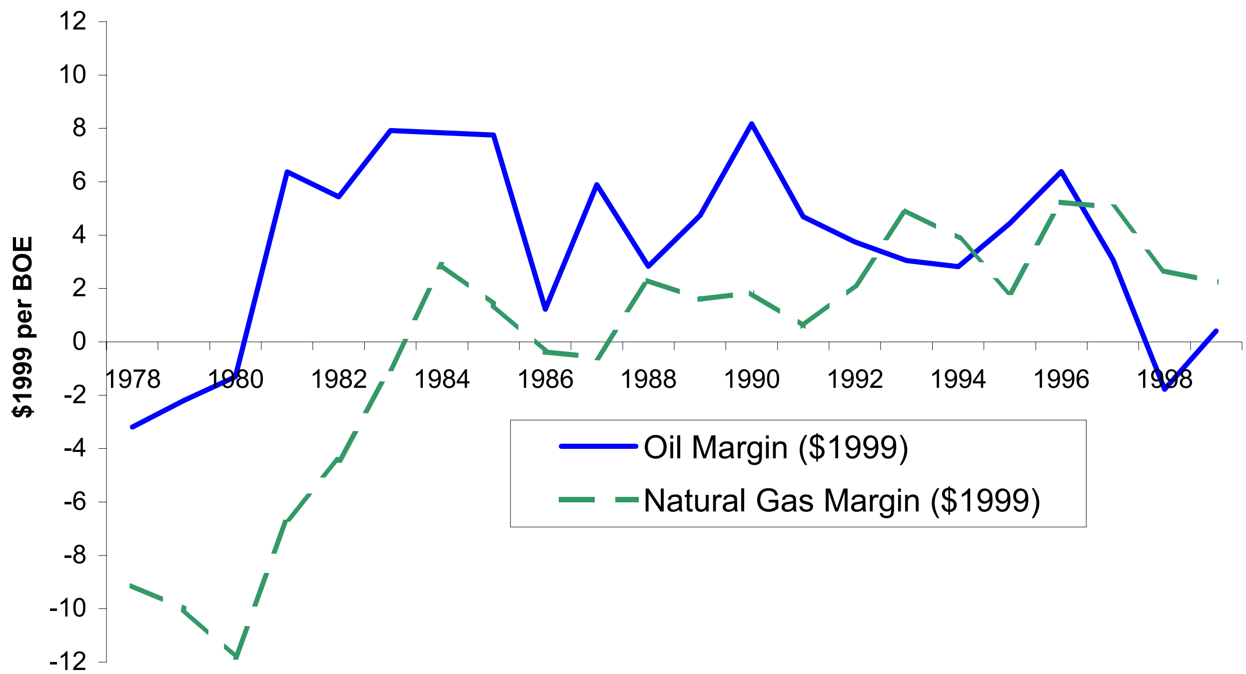
Note: BOE= barrels of oil equivalent. Natural gas converted at 1 mcf= 0.178 barrels
Source :Energy Information Administration, Form EIA-28 (Financial Reporting System).

Figure 15. Onshore and Offshore Finding Costs for FRS Companies, 1978-1999



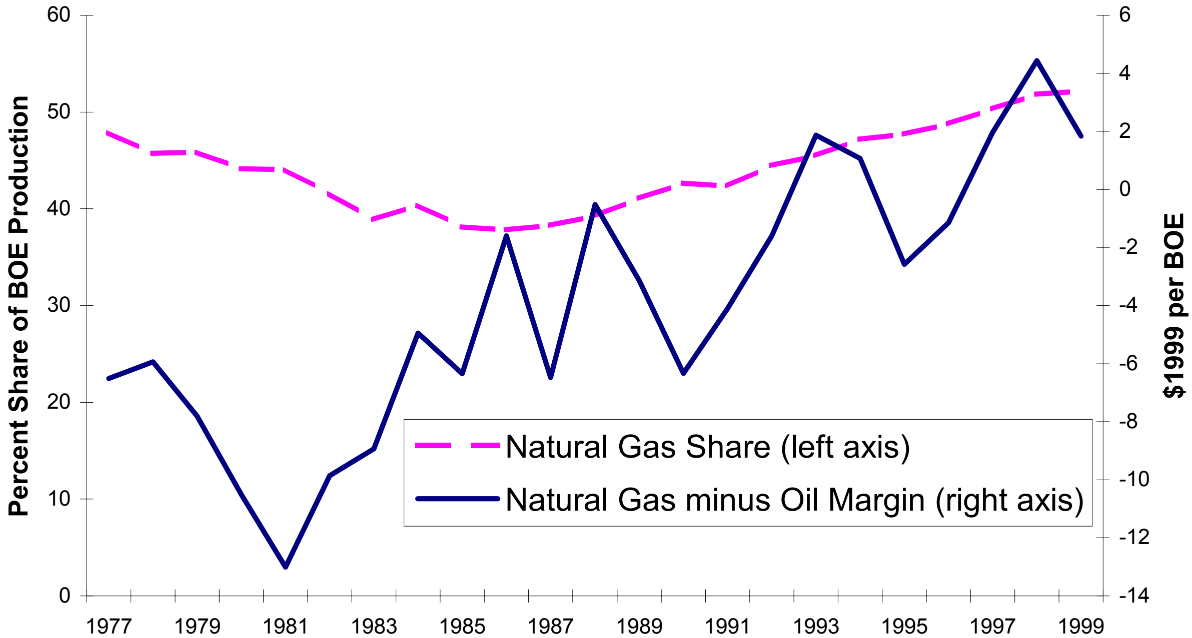
Note: BOE= barrels of oil equivalent. Natural gas converted at 1 mcf= 0.178 barrels
Finding costs = exploration and development expenditures / reserve additions (excluding purchases), 3-year weighted average
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Figure 16. U.S. Oil Margins and Natural Gas Margins for FRS Companies, 1978-1999



Note: BOE= barrels of oil equivalent. Natural gas converted at 1 mcf= 0.178 barrels
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Figure 17. Natural Gas Share of U.S. Oil and Natural Gas Production and Gas minus Oil Margin for FRS Companies, 1977-1999



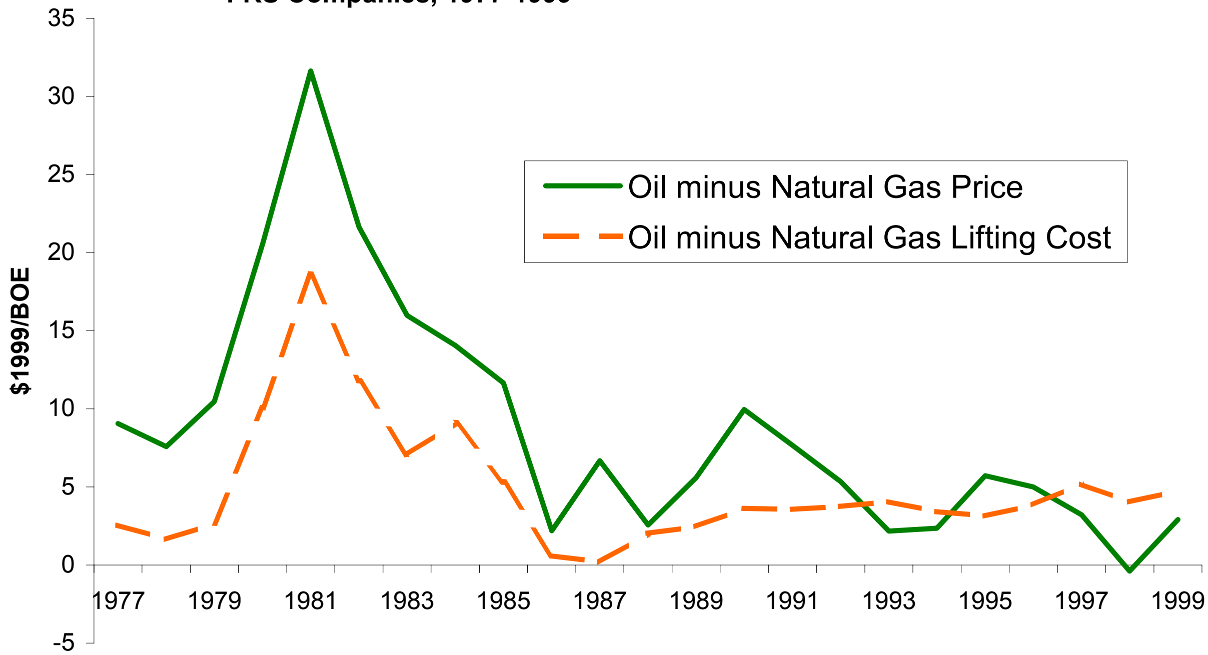
Note: BOE= barrels of oil equivalent. Natural gas converted at 1 mcf= 0.178 barrels
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

continued into the first half of the 1980's, indicating some lags in responding to the changes in relative profitability.

From 1982 through 1999, natural gas margins improved relative to oil margins more often than not. On balance, the difference in margins showed a strong upward trend over this period. Differences in both oil and natural gas prices and the costs of oil and natural gas production were important in these movements. From 1987 on, oil lifting costs rose relative to natural gas lifting costs (Figure 18). By the late 1990's, oil lifting costs were $4.75 ($1999) per BOE, or $0.84 per Mcf, higher than natural gas lifting costs. In 1990, U.S. oil prices were $9.97 per BOE ($1999) higher than U.S. natural gas prices. Thereafter, the difference generally declined, hitting $2.91 per barrel in 1999. As natural gas margins generally improved relative to oil margins in the 1980's and 1990's, the majors' U.S. natural gas production grew relative to their oil production.

A quantitative version of the response of the majors to the difference between natural gas and oil margins can be gained by statistically estimating a relationship between the natural gas share of upstream production and the natural gas minus oil margin shown in Figure 17. Estimating a linear regression between the contemporaneous values of these two variables appears to show, by conventional thresholds of statistical significance, a positive role for the natural gas minus oil margin. However, this simple linear regression ("the traditional static model") turned out to have problems that belie measures of statistical significance. These problems arise because there are lags between movements in the margins and shifts in the majors' composition of upstream production. Estimating a regression that takes account of these lags ("the partial adjustment model") yielded a relationship that (1) indicated a significantly positive relationship between the natural gas production share and the natural gas minus oil margin, (2) indicated that there is a lag between adjustment of the natural gas production share and changes in the natural gas minus oil margin, and (3) did not have the statistical problems that the simpler approach had.[Note 15]

Figure 18. Differences in Oil and Natural Gas Prices and Costs for FRS Companies, 1977-1999



Note: BOE= barrels of oil equivalent. Natural gas converted at 1 mcf= 0.178 barrels
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

The majors' shift to natural gas in their U.S. upstream operations appears to be explained well by the partial adjustment model (Figure 19). The values predicted by the partial adjustment model and actual values of the majors' natural gas share of U.S. upstream production are close over the entire 1978 to 1999 period. These results indicate that the relative profitability of natural gas versus oil pretty well explains both the majors' shift toward natural gas from the mid-1980's through 1999 as well as their earlier shift away from natural gas.

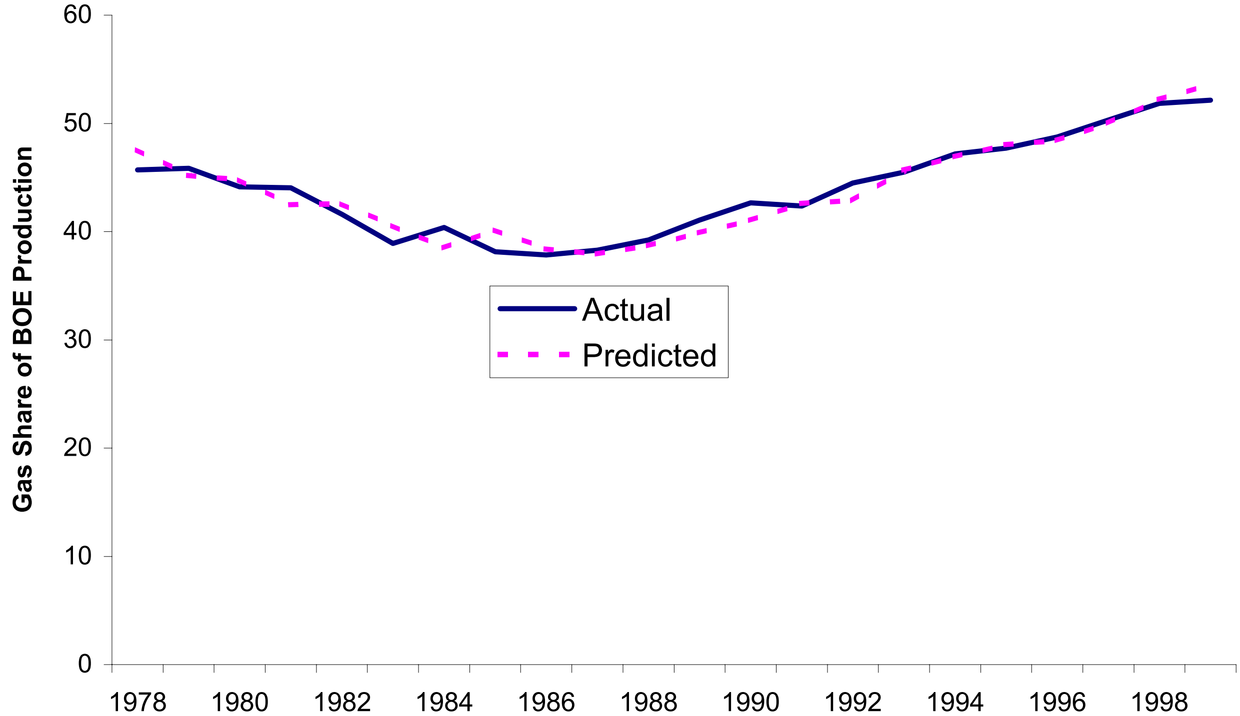
These results should not be interpreted as indicating that the turmoil in U.S. natural gas markets of the last 25 years or so, due to market developments and regulatory policy changes, had no effect on the majors' decisions to invest or not invest in natural gas. Rather, it is through their effects on natural gas and oil prices, production costs, and finding costs that policy changes and market turmoil have affected decisions to invest in natural gas.

The Future Role of the Majors in U.S. Natural Gas Supply

Continued Movement by the Majors to Natural Gas Production Probable

The FRS data for the 2000 reporting year were still in process at the time this report was written. Nevertheless, since annual changes in lifting costs and finding costs have tended to be small in recent years, margins can be estimated by utilizing overall U.S. wellhead prices and 1999 lifting and finding costs.

Figure 19. Partial Adjustment Model: Actual vs. Predicted Values of Gas Share, 1978-1999



The estimated margins for both oil and natural gas were at all-time high levels in 2000 (Figure 20). Based on price forecasts contained in EIA's Short-Term Energy Outlook(September 2001)[Note 16] for 2001, estimated natural gas margins will be at another record high, and oil margins will be down somewhat from their apparent peak in the prior year, but still at a historically high level.

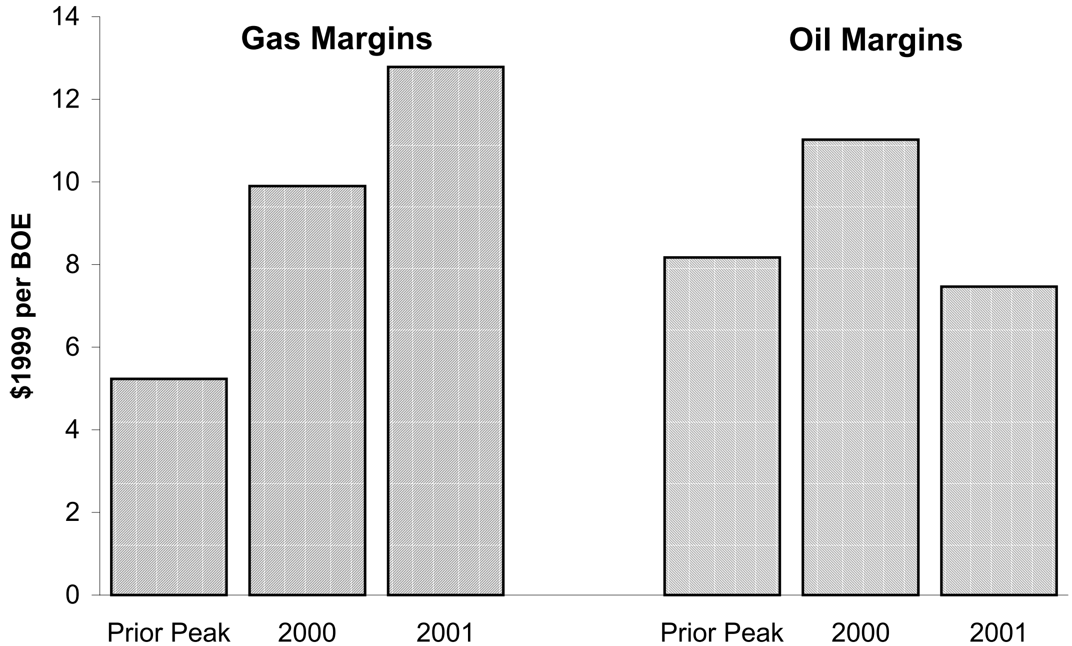
The sharp upswing in margins led to a jump in U.S. exploration and development activity. The average monthly rig count for 2000 relative to 1999 was up 45 percent for natural gas.[Note 17] Rigs drilling for oil were up a steeper 54 percent, as the oil margin exceeded the natural gas margin in 2000. The apparent record high natural gas margins in 2001 led to a 51-percent increase in the number of natural gas rigs (based on data through June) to 951. Oil rigs were up a lesser 34 percent. These results suggest a continued shift toward natural gas, at least through the first half of 2001.

The greater attractiveness of U.S. natural gas over U.S. oil as a target of investment of the majors could continue into the longer term. The EIA's most recent *Annual Energy Outlook* (December 2000) projects a 2.3-percent average annual growth in U.S. natural gas demand through 2020, nearly twice the projected 1.3-percent growth in petroleum demand.[Note 18]

Recent Developments and the Majors' Future Role in U.S. Natural Gas Supply

The majors' long-running shift to natural gas in their U.S. upstream operations has had little effect on their share of overall U.S. natural gas production. In 1986, the majors produced 7.1 Tcf of natural gas in the United States, an amount equal to 38 percent of their combined oil and natural gas production. They steadily increased their U.S. natural gas production to a peak of 8.4 Tcf in 1998 before falling off to 8.0 Tcf in 1999. In these latter two years, the natural gas share of their U.S. upstream production was 52

Figure 20. Estimated Margins for Gas and Oil, 2000-2001



Note: BOE= barrels of oil equivalent. Natural gas converted at 1 mcf= 0.178 barrels. Margins were estimated from price estimates in EIA's *Short-Term Energy Outlook* (September 2001).

percent. Over the 1986 to 1999 period, though, the majors' share of total U.S. natural gas production (on a net ownership basis) varied within a narrow range of 54 percent to 58 percent, with no evident trend since 1987. Consequently, even if the majors continue to shift to natural gas, there appears to be no compelling evidence that their share of total U.S. natural gas production might be expected to grow.

Although the majors' share of total U.S. natural gas *production* might not grow, several recent developments suggest that their role in U.S. natural gas *supply* is likely to grow. Supply includes not only production and short-run inventory adjustments but also net imports. About 94 percent of natural gas imports into the United States come from Canada, accounting for 16 percent of U.S. natural gas consumption.[Note 19] Several of the FRS companies have been investing in Canadian natural gas in recent years, both through the drill bit and through acquisitions. Recent acquisitions of Canadian oil and natural gas assets include Burlington Resources' acquisition of Poco Petroleums (1999), Conoco's acquisition of producing Canadian properties from Renaissance Energy (1999), Phillips Petroleum's acquisition of properties from Gulf Canada Resources (1997), Union Pacific's (acquired by FRS respondent Anadarko Petroleum in 2000) acquisition of Norcen Energy Resources (1998), Unocal's gain of a 48-percent interest in Northrock Resources (1999), and USX's acquisition of Tarragon Oil and Gas (1998). In 1999, Exxon Mobil announced the completion of the $2 billion Sable Offshore Energy Project. This project includes platforms located offshore of Nova Scotia and a pipeline to New England natural gas markets. Also in Canada, Chevron is working the oil and natural gas frontiers of the Northwest Territories while BP Amoco continues to work Amoco's oil and natural gas legacies in Canada. These developments are likely to lead to growth in the majors' Canadian natural gas production and their role in U.S. natural gas supply via exports to the United States.

The remainder of natural gas imports into the United States comes almost entirely in the form of liquefied natural gas (LNG). LNG is transported by pressurized tanks in specialized ocean-going vessels. LNG tankers transport natural gas from producing areas to specialized offloading facilities in consuming areas for ultimate distribution.

Most of the LNG trade occurs in the Asia-Pacific region.[Note 20] Over 70 percent of global exports of LNG go to Japan, South Korea, and Taiwan. Of this amount, 75 percent is produced and transported from fields in the Asia-Pacific region, with the balance coming from Mideast locales. The second largest nexus of LNG trade is between Africa (mainly Algeria) and Europe, which accounted for 23 percent of LNG volumes in 2000. Imports of LNG into the United States amounted to less than 5 percent of the worldwide total.

Several FRS companies are active in LNG operations.[Note 21] Most of the companies' LNG-related activities are directed toward supplying Asian markets, primarily Japan. Majors supplying LNG in Asia and their associated natural gas production locales include Exxon Mobil (Indonesia and Qatar), Enron (Qatar), Chevron (Australia), Phillips Petroleum (Australia), Unocal (Indonesia), and USX (Alaska). Closer to the United States is the Atlantic LNG plant in Trinidad-Tobago in which BP Amoco gained Amoco's 34-percent interest after their merger in late 1998. In the United States, Williams Companies acquired the LNG import facilities in Cove Point, Maryland, in 2000. Williams plans to reactivate the plant and make upgrades in 2002 and 2003. El Paso is reactivating an LNG terminal near Savannah, Georgia, which the company expects to be in service in late 2001.

Within the United States, LNG composed only 6 percent of natural gas imports in 2000. Nevertheless, several investments in LNG facilities to serve the U.S. market have been announced in 2001. Majors that have announced planned LNG projects in North America, in addition to the reactivations of El Paso and Williams noted above, include BP Amoco, Chevron, Enron, and El Paso.[Note 22] As LNG grows as a source of natural gas for the United States, so will the role of the majors in U.S. natural gas supply. However, the timing of the LNG projects could be affected by declines in natural gas prices subsequent to their announcements.

High U.S. natural gas prices in the past two winters have led to a renewed interest in the prospect of transporting natural gas from Alaska's North Slope to the lower 48 states. Currently, most of the Alaskan natural gas production is reinjected, largely for lack of economic outlets. Several of the FRS companies are prominent in Alaskan oil and natural gas production, owning nearly all of the proven reserves there. A pipeline that can move natural gas from Alaska to the lower 48 states, if built, would increase the majors' share of U.S. natural gas supply.

Lastly, coalbed methane production might boost the majors' share of U.S. natural gas production. Assessing the likely course of U.S. coalbed methane production is problematic. On one hand, the Section 29 credits for coalbed methane production from wells drilled before 1993 is due to expire at the end of 2002. If the credit is renewed by the Congress, then there should be a stimulus to future coalbed methane production. If the credit ceases, it is uncertain what the effect will be. On the other hand, after 1992, coalbed methane drilling and development of production not eligible for the tax credit has continued.

Also, in recent months, some majors have sought to increase their coalbed methane reserves and exploratory acreage in potential coalbed methane regions through acquisitions of companies. In August, 2001, Williams Companies acquired Barrett Resources for $2.6 billion.[Note 23] Barrett Resources is primarily a coalbed methane producer in the Rocky Mountain region. USX acquired Pennaco Energy in March, 2001, for $500 million.[Note 24] Pennaco is a coalbed methane producer in the Powder River Basin located in Wyoming and Montana. Texaco acquired EnerVest San Juan for $121 million in January, 2001. The acquired assets are coalbed methane properties in the San Juan Basin of Colorado and New Mexico.[Note 25] In September, 2000, Phillips Petroleum acquired coalbed methane properties in Alabama and the Powder River Basin for $123 million.[Note 26]

Ongoing coalbed methane projects and recent acquisitions indicate a continuing interest in coalbed methane by the majors even if eligibility for Section 29 credits expires.

On balance, the following developments could increase the majors' role in U.S. natural gas supply:

- An increase in the majors' volume of natural gas exports to the United States, both direct and indirect, appears likely, through growth in their Canadian natural gas production and investments in LNG transport and facilities.

- The prevalence of majors in Alaska reserve ownership and production will increase their share of U.S. natural gas supply if a pipeline is built to transport natural gas to the lower 48 states.

- The majors' continued interest in coalbed methane production, which accounted for a major share of their growth in U.S. natural gas production in the 1990's, should increase their share of total U.S. production.

Endnotes

[1]For a list of the FRS companies, see the Appendix.

[2]Natural gas is converted at a rate of 0.178 barrels per thousand cubic feet.

[3]For an overview of U.S. natural gas market developments and regulatory policy changes see *The Evolution of Gas Markets in the United States* at http://www.eia.doe.gov/oil_gas/natural_gas/presentations/nat_presentations.html

[4]This calculation was made using successively applied sets of assumptions. The first set of assumptions was that no reserves were added or purchased over the 1986 to 1999 period and remaining reserves were extracted at the 1986 rate for the entire period. Under these assumptions, implied production in 1999 would be 1,937 Bcf. Next, assume reserve additions (excluding purchases of proved reserves) over the 1986 to 1999 period were equal to their actual values, but reserves were extracted at the 1986 rate for the entire period. In this case, implied 1999 production would be 6,284 Bcf. Thus, an estimate of the increment in 1999 production due to actual reserve additions (excluding purchases of proved reserves) is 6,284 Bcf - 1,937 Bcf = 4,347 Bcf. Thirdly, assume reserve additions and net purchases of proved reserves were equal to their actual values over the 1986 to 1999 period and the extraction rate was assumed equal to the 1986 rate. In this case, implied 1999 production would be 6,203 Bcf and the change attributable to net purchases can be estimated as 6,203 Bcf - 6,284 Bcf = -81 Bcf. Finally, the increment in 1999 production attributable to increased extraction is 7,994 Bcf (actual 1999 production) - 6,203 Bcf = 1,791 Bcf. Thus, the sources of increased production are reserve additions, 72 percent (i.e., 4,347/(7,994 - 1,937)); net purchases and entry, -1 percent; and increased extraction rate, 30 percent.

[5]Since some of the majors' disclosures to the FRS of their Section 29 tax credits were not publicly disclosed, the companies receiving Section 29 tax credits cannot be identified in this report.

[6]Credit = $3 - $3* x (RP - $23.50*)/$6*, where RP is the current reference price of a barrel of oil equivalent, and * indicates figures are indexed for inflation.

[7]Based on data from *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1999 Annual Report* at http://www.eia.doe.gov/oil_gas/natural_gas/data_publications/crude_oil_natural_gas_reserves/cr.html , Tables 12 and D5.

[8] http://www.eia.doe.gov/oil_gas/natural_gas/info_glance/prices.html

[9]http://www.eia.doe.gov/emeu/perfpro/chapter2.html

[10]Ordinary least-squares regressions were run. For the years 1980 to 1985, when the companies paid the Windfall Profit Tax (WPT) on oil production, the regressions were run excluding the WPT. The WPT was then allocated to oil production, but not natural gas production.

[11]The mean of the difference between oil lifting costs and natural gas lifting costs over the 1977 to 1999 period ($1999) was $4.28 per BOE onshore and $5.83 per BOE offshore, with associated t-ratios of 3.89 and 6.51, respectively.

[12]The mean of the difference between onshore and offshore natural gas lifting costs over the 1977 to 1999 period ($1999) was $2.08 per BOE and $0.53 per BOE between onshore and offshore oil lifting costs with associated t-ratios of 5.44 and 0.87, respectively.

[13]*Oil and Gas Development in the United States in the Early 1990's* at http://www.eia.doe.gov/emeu/perfpro/independ/contents.html , notes 13 and 14.

[14]For example, for 1999, ordinary least squares yielded the following result for onshore finding costs

$$\underset{(1.51)}{F = 5.02} + \underset{(0.94)}{4.51\ s}$$

where F = onshore finding costs ($1999 per BOE of reserve additions), s = natural gas share of oil and natural gas reserve additions (3-year weighted average), and the t-ratios of the estimated coefficients are in parentheses. The coefficient on the variable s is an estimate of the *difference* between natural gas and oil finding costs. As can be seen by the t-ratio, the estimated difference is not different from zero by the usual statistical conventions. Overall, the statistical fit is very poor, as the R^2 was essentially nil.

[15]The ordinary least-squares regression between the aggregate value of the natural gas share of oil and natural gas production (GSHR) for FRS companies and the natural gas margin minus the oil margin, over the 1977 to 1999 period (GOMARGIN) yielded (t-ratios in parentheses):

$$\underset{}{GSHR_t} = \underset{(42.30)}{46.00} + \underset{(2.55)}{0.47}\ GOMARGIN_t\ ,\ t = 1977\text{-}1999.$$

The above regression had a Durbin-Watson statistic of 0.27, indicating strong serial correlation of the regression errors. Also, the R^2 (adjusted) of 0.200 is on the low side for an aggregate time-series regression.

An often-used partial adjustment model is of the form

$$Y_t - Y_{t-1} = a(Y^*_t - Y_{t-1})$$

This expression says that a decision-making unit, say a company, in deciding on this period's value of a decision variable (Y_t), makes up a fraction (a) of the difference between the optimal level seen currently (Y^*_t) and the value at the end of the last period (Y_{t-1}).

In the context of this report, Y_t is the natural gas share of oil and natural gas production ($GASHR_t$) and the optimal level depends on the difference between the natural gas margin and the oil margin ($GOMARGIN_t$). To allow for lags in recognition, both current and prior-period values of the margin difference variable are included. Ordinary least-squares estimates of the partial adjustment model in the context of this report yielded (t-ratios in parentheses):

$$GSHR_t = \underset{(1.94)}{6.10} + \underset{(1.54)}{0.13}\ GOMARGIN_t + \underset{(1.51)}{0.14}\ GOMARGIN_{t-1} + \underset{(12.97)}{0.89}\ GSHR_{t-1}$$

Although the t-ratios of the margin variables are a bit below conventional levels of statistical significance, the t-ratios of the sum of the coefficients of the margin variables is 4.18, which is well above the conventional levels of significance. The R^2 (adjusted) is 0.93 (with a maximum possible value of 1.0) which is a large improvement over the traditional static model. Durbin's h statistic of 0.84 suggests the absence of the serial correlation problem that affected the traditional static model.

If the ratio of natural gas production to oil production (which does not have an upper bound of 100 percent) is substituted for GSHR (which does have an upper bound of 100 percent) in the above regression, a nearly identical coefficient on the lagged dependent variable and t-ratios of the coefficients are obtained:

$$GAS/OIL_t = \underset{(2.12)}{11.87} + \underset{(1.81)}{0.47}\ GOMARGIN_t + \underset{(1.54)}{0.44}\ GOMARGIN_{t-1} + \underset{(13.93)}{0.91}\ GAS/OIL_{t-1}$$

where GAS/OIL is the ratio (percent) of natural gas production to oil production.

[16]http://www.eia.doe.gov/emeu/steo/pub/4tab.html

[17]http://www.eia.doe.gov/emeu/mer/resource.html

[18]http://www.eia.doe.gov/oiaf/aeo/

[19]http://www.eia.doe.gov/emeu/mer/natgas.html

[20]http://www.bp.com/downloads/701/global_stats_workboot.XLS

[21]The information in this paragraph was drawn from the companies' filings of Securities and Exchange Commission Form 10K for the 2000 reporting year.

[22]*Petroleum Intelligence weekly* (April 9, 2001), p. 12.

[23]Williams Companies, Press Release (August 2, 2001).

[24]USX Corporation, Press Release (March 27, 2001).

[25]Texaco, Inc., Press Release (January 9, 2001).

[26]Phillips Petroleum Company, Press Release (September 25, 2000).

Appendix

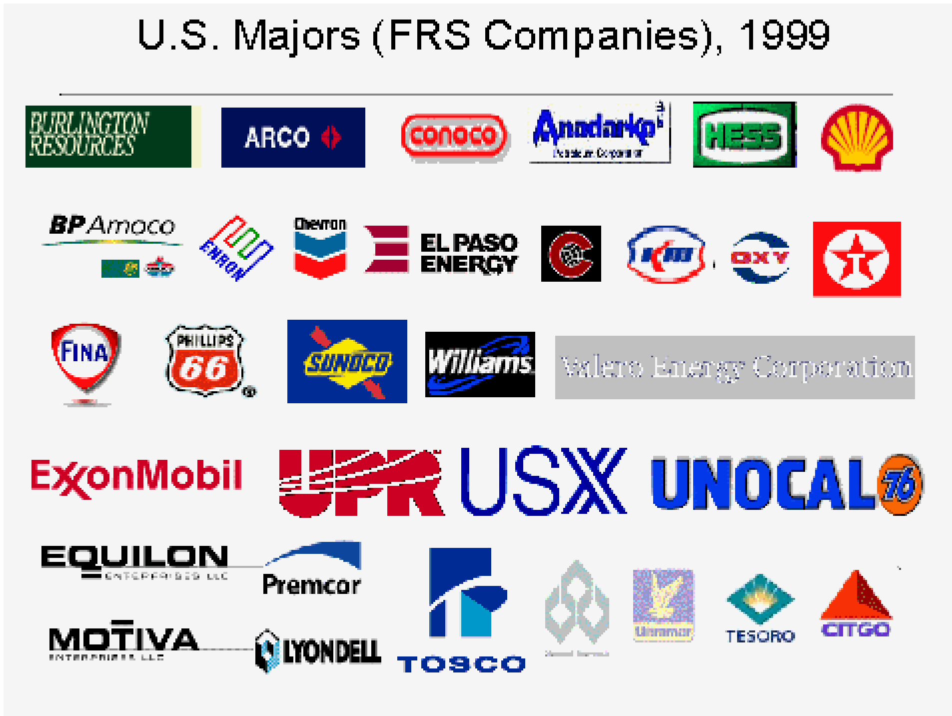

U.S. Majors (FRS Companies), 1999
BURLINGTON RESOURCES
ARCO
conoco
Anadarko
HESS
BP Amoco
ENRON
Chevron
EL PASO ENERGY
OXY
FINA
PHILLIPS 66
SUNOCO
Williams
Valero Energy Corporation
ExxonMobil
UPR
USX
UNOCAL 76
EQUILON
Premcor
MOTIVA
LYONDELL
TOSCO
TESORO
CITGO

Table A1. Companies Reporting to the Financial Reporting System, 1974-1999

Company	1974-1981	1982	1983-1984	1985-1986	1987	1988	1989-1990	1991	1992-1993	1994-1996	1997	1998	1999
Amerada Hess Corporation	X	X	X	X	X	X	X	X	X	X	X	X	X
American Petrofina, Inc.[a]	X	X	X	X	X	X	X						
BP Amoco Corporation[b c]	X	X	X	X	X	X	X	X	X	X	X	X	X
Anadarko Petroleum Corporation								X	X	X	X	X	X
Ashland Inc. [d]	X	X	X	X	X	X	X	X	X	X	X		
Atlantic Richfield Co. (ARCO)	X	X	X	X	X	X	X	X	X	X	X	X	X
BP America, Inc.[c e]					X	X	X	X	X	X	X	X	X
Burlington Northern Inc.[f]	X	X	X	X	X								
Burlington Resources Inc.[f]						X	X	X	X	X	X	X	X
Chevron Corporationg [h]	X	X	X	X	X	X	X	X	X	X	X	X	X
Citgo Petroleum Corporation												X	X
Cities Service[i]	X	X											
Clark Refining and Marketing, Inc.												X	X
The Coastal Corporation	X	X	X	X	X	X	X	X	X	X	X	X	X
Conoco [j k]	X											X	X
E.I. du Pont de Nemours and Co.[j k]		X	X	X	X	X	X	X	X	X	X		
El Paso Energy Corporation													X
Enron Corp.									X	X	X	X	X
Equilon Enterprises, LLC [l]												X	X
Exxon Mobil Corporation [m]	X	X	X	X	X	X	X	X	X	X	X	X	X
Fina, Inc.[a]								X	X	X	X	X	X
Getty Oil[n]	X	X	X										
Gulf Oil[h]	X	X	X										
Kerr-McGee Corporation [o]	X	X	X	X	X	X	X	X	X	X	X	X	X
LYONDELL-CITGO Refining, LP [p]												X	X
Marathon [q]	X												
Mobil Corporation [m r]	X	X	X	X	X	X	X	X	X	X	X	X	
Motiva Enterprises LLC [s]												X	X
Nerco, Inc.[t]									X				
Occidental Petroleum Corporation[i]	X	X	X	X	X	X	X	X	X	X	X	X	X
Oryx Energy Company[o u]						X	X	X	X	X	X		
Phillips Petroleum Company	X	X	X	X	X	X	X	X	X	X	X	X	X
Shell Oil Company	X	X	X	X	X	X	X	X	X	X	X	X	X
Sonat Inc.											X	X	
Standard Oil Co. (Ohio) (SOHIO)[e]	X	X	X	X									
Sun Company, Inc.[u v]	X	X	X	X	X	X	X	X	X	X		X	X
Superior Oil[r]	X	X	X										
Tenneco Inc.[w]	X	X	X	X	X	X							
Tesoro Petroleum Corporation												X	X
Texaco Inc.[n]	X	X	X	X	X	X	X	X	X	X	X	X	X
Tosco Corporation												X	X
Total Petroleum (North America) Ltd.[x]							X	X					
Ultramar Diamond Shamrock Corporation												X	X
Union Pacific Resources Group, Inc. [y]	X	X	X	X	X	X	X	X	X	X	X	X	X
Unocal Corporation	X	X	X	X	X	X	X	X	X	X	X	X	X
USX Corporationq	X	X	X	X	X	X	X	X	X	X	X	X	X
Valero Energy Corporation												X	X
The Williams Companies, Inc.												X	X

[a]American Petrofina, Inc. changed its name to Fina, Inc., effective April 17, 1991.

[b]Formerly Standard Oil Company (Indiana).

[c]Amoco merged with British Petroleum plc and became BP Amoco plc on December 31, 1998. BP America was renamed BP Amoco, Inc. The companies reported separately for 1998.

[d]Ashland was dropped from the FRS system for 1998 after spinning off downstream and coal operations and disposing of upstream operations.

[e]In 1987, British Petroleum acquired all shares in Standard Oil Company (Ohio) that it did not already control and renamed its U.S. affiliate, BP America, Inc.
[f]Burlington Resources was added to the FRS system and Burlington Northern was dropped for 1988. Data for Burlington Resources covers the full year 1988 even though that company was not created until May of that year.

[g]Formerly Standard Oil Company of California.

[h]Chevron acquired Gulf Oil in 1984, but separate data for Gulf continued to be available for the full 1984 year.

[i]Occidental acquired Cities Service in 1982. Separate financial reports were available for 1982, so each company continued to be treated separately until 1983.

[j]DuPont acquired Conoco in 1981. Separate data for Conoco were available for 1981; DuPont was included in the FRS system in 1982.

[k]Dupont was dropped from the FRS system when Conoco was spun-off in 1998. Conoco began reporting separately again in 1998.

[l]Equilon is a joint venture combining Shell's and Texaco's western and midwestern U.S. refining and marketing businesses and nationwide trading transportation and lubricants businesses. Net income is duplicated in the FRS system since Shell and Texaco account for this investment using the equity method.

[m]In December 1998, Exxon and Mobil agreed to merge. Both companies reported separately for 1998.

[n]Texaco acquired Getty in 1984; however, Getty was treated as a separate FRS company for that year.

[o]In 1998, Kerr-McGee and Oryx merged. The financial reporting for both was consolidated under Kerr-McGee for 1998.

[p]LYONDELL-CITGO is a limited partnership owned by Lyondell Chemical Company and Citgo. There will be some duplication of net income since Citgo accounts for its investment using the equity method.

[q]U.S. Steel (now USX) acquired Marathon in 1982.

[r]Mobil acquired Superior in 1984, but both companies were treated separately for that year.

[s]Motiva is a joint venture approximately equally owned by Shell, Texaco and Saudi Refining, Inc. The joint venture combines the company's Gulf and east coast refining and marketing businesses. Duplication exists for the net income related to Shell and Texaco's interests which are accounted for under the equity method.

[t]RTZ America acquired the common stock of Nerco, Inc., on Feb. 17, 1994. In Sept. 1993, Nerco, Inc. sold Nerco Oil & Gas, Inc., its subsidiary. Nerco's 1993 submission includes operations of Nerco Oil & Gas, Inc., through Sept. 28, 1993.

[u]Sun Company spun off Sun Exploration and Development Company (later renamed Oryx Energy Company) during 1988. Both companies were included in the FRS system for 1988; therefore, some degree of duplication exists for that year.

[v]Sun company withdrew from oil and gas exploration and production in 1996. Sun’s 1996 submission includes oil and gas exploration and production activities through September 30, 1996. Refining/marketing activities are included for the entire 1996 calendar year.

[w]Tenneco sold its worldwide oil and gas assets and its refining and marketing assets in 1988. Other FRS companies purchased approximately 70 percent of Tenneco's assets.

[x]Effective June 1, 1991, Total's exploration, production, and marketing operations in Canada were spun off to Total Oil & Gas, a new public entity.

[y]Effective October 15, 1996, Union Pacific Corporation distributed its ownership in the Union Pacific Resources Group, Inc. to its shareholders. Prior to 1996, the FRS system included Union Pacific Corporation. The FRS system includes only Union Pacific Resources Group, Inc. for 1996.

“X” indicates that the company was included in the FRS system for the year indicated.

Source: Energy Information Administration, Form EIA-28, “Financial Reporting System”.