4. Resource Development Trends

This chapter of *Performance Profiles* addresses the costs of finding oil and natural gas and other resource development issues. While the costs of adding oil and gas reserves (finding costs) do not directly affect the current-year bottom line of the FRS companies (see Chapter 3), they are important in guiding the scale and scope of the companies' current and future resource development strategies. Accordingly, this chapter also discusses the geographical areas of most importance to the FRS companies' current resource development initiatives. Specifically, this chapter presents four analyses ("Special Topics") that discuss:

- Variations in regional finding costs
- Development in the Gulf of Mexico
- Natural gas production in the United States
- The Mackenzie pipeline and implications for the U.S. natural gas market

SPECIAL TOPIC: Finding Costs Increased in Most Regions

Average finding costs rose worldwide, boosted by increases in six of the nine FRS regions for the 2000 to 2002 period, with Canada again experiencing the highest costs as it had for the 1999 to 2001 period (Table 19). Compared to the second-most-costly region, Canada's costs increased from $3 per barrel of oil equivalent for the 1999 to 2001 to $5.51 for the 2000 to 2002 period and had the largest absolute increase for the 2000 to 2002 finding costs for any FRS region.

Finding costs are the costs of adding oil, including crude oil and natural gas liquids, and dry natural gas proven reserves via exploration and development activities.[a] They are measured for oil and gas on a combined basis in units of dollars per barrel of oil equivalent (BOE). Ideally, finding costs would include all the costs incurred (no matter when these costs were incurred or actually recognized on a company's books) in finding any particular proven reserves (not including the purchases of already discovered reserves). In practice, finding costs are actually measured as the ratio of exploration and development expenditures (excluding the expenditures on proved acreage) to proven reserve additions (excluding net purchases of proven reserves) over a specified period of time.[b] Finding costs are generally measured in *Performance Profiles* as a weighted average over a period of three years to accommodate leads and lags in data reporting, and, if several years of data are presented, they are usually reported in constant dollars to facilitate comparisons over time.

Other prominent changes in regional finding costs for the FRS companies for the 2000 to 2002 period include the largest proportional increase in finding costs in OECD Europe and a notable increase in the U.S. Onshore (Table 19). The large increase in OECD Europe (predominantly the North Sea) raised that region to the second-highest region for finding costs, while the increase in the U.S. Onshore pushed it into virtual tie with the U.S. Offshore (predominantly the Gulf of Mexico) for the third highest-cost region. The large decrease in finding costs for the FRS companies in the Middle East for the 2000 to 2002 period is of little significance because, with the unfavorable investment climate in the Middle East,

this region is usually the one with the smallest amount of reserve additions through the drill bit for the FRS companies.

Table 19. Finding Costs by Region for FRS Companies, 1999-2001 and 2000-2002
(Dollars per Barrel of Oil Equivalent)

Region	1999-2001	2000-2002	Percent Change
United States			
Onshore	6.01	7.62	26.7
Offshore	6.99	7.59	8.6
Total United States	6.39	7.61	19.1
Foreign			
Canada	10.70	14.83	38.6
OECD Europe	5.51	9.32	69.3
Former Soviet Union and Eastern Europe	3.26	3.10	-4.9
Africa	3.68	3.68	0.0
Middle East	7.66	5.94	-22.5
Other Eastern Hemisphere	4.07	4.63	13.7
Other Western Hemisphere	6.22	5.14	-17.5
Total Foreign	5.25	5.92	12.6
Worldwide	5.78	6.70	16.0

Notes: The above figures are 3-year weighted averages of exploration and development expenditures (current dollars), excluding expenditures for proven acreage, divided by reserve additions, excluding net purchases of reserves. Gas is converted to barrels of oil equivalent on the basis of 0.178 barrels of oil per thousand cubic feet of gas.

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

In order to understand the basis for finding cost increases or decreases, one must look at its two components -- finding rates and expenditures per well. Finding rates are the average amount of proved reserves added by the drill bit (through extensions and discoveries, improved recovery, and revisions to previous reserves estimates) per well drilled.

Ideally, reserve additions per well are measured as the average of the reserves added by each well during its lifetime (no matter the date that the well was completed or the reserves added). In practice, additions to reserves per well are actually measured as the ratio of total proven reserve additions (excluding net purchases) to the number of wells completed (including dry holes) during a specified period of time, with no attempt to link reserve increases to individual wells.[c]

Similarly, expenditures per well are ideally measured as the average of the exploration, development, and unproved acreage expenditures associated with each well during its lifetime. In practice, expenditures per well are the total expenditures on exploration, development, and unproved acreage divided by the number of wells completed during a particular time period, with no attempt to link expenditures to individual wells.

These two ratios are generally measured in *Performance Profiles* as a weighted average over a period of three years (in part, to compensate for the imperfect way they are measured), and, if several years of data are presented, expenditures are usually reported in constant dollars (to facilitate comparisons over

time). Finding costs are then the expenditures (to find additional reserves) per well completed divided by the finding rate (proven reserve additions per well completed).

Worldwide finding rates and expenditures per well for the FRS companies both fell for the 2000 to 2002 period (Table 20). However, the increase in worldwide finding costs, as shown in Table 19, resulted from finding rates falling faster than expenditures per well.[d] In other words, the relatively larger decline in the worldwide finding rate was the sole reason that finding costs rose. In Canada, the region with the largest absolute increase in finding costs for the 2000 to 2002 period, a 13-percent decline in the expenditures per well was more than offset by a 37-percent decline in the finding rate. Finding costs in OECD Europe rose so much because the finding rate there fell while expenditures per well rose (both of which resulted in increased finding costs). For the U.S. Onshore, expenditures per well changed little while the finding rate fell. In each of these instances, the fall in finding rates was the more prominent contributor to increased finding costs.

Table 20. Finding Rates and Expenditures per Well by Region for FRS Companies, 1999-2001 and 2000-2002

Region	Finding Rates (Thousand Barrel of Oil Equivalent per Well)			Expenditures Per Well (Thousand Dollars per Well)		
	1999-2001	2000-2002	Percent Change	1999-2001	2000-2002	Percent Change
United States						
Onshore	354	293	-17.2	2,128	2,232	4.9
Offshore	2,258	2,293	1.5	15,782	17,391	10.2
Total United States	522	437	-16.3	3,332	3,322	-0.3
Foreign						
Canada	162	102	-37.4	1,738	1,508	-13.2
OECD Europe	6,087	4,185	-31.2	33,519	39,024	16.4
Former Soviet Union and Eastern Europe	10,067	13,913	38.2	32,776	43,068	31.4
Africa	6,715	6,057	-9.8	24,687	22,263	-9.8
Middle East	438	831	89.7	3,358	4,940	47.1
Other Eastern Hemisphere	1,728	1,338	-22.6	7,034	6,193	-12.0
Other Western Hemisphere	2,127	1,721	-19.1	13,240	8,836	-33.3
Total Foreign	1,084	817	-24.6	5,696	4,836	-15.1
Worldwide	723	582	-19.6	4,180	3,900	-6.7

Notes: The above finding rates are 3-year weighted averages of reserve additions, excluding net purchases of reserves, divided by number of wells completed, and the above expenditures per well are 3-year weighted averages of exploration and development

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

Finding Costs for Many Regions Show Consistent Patterns Since Early 1990's

Regional finding costs vary substantially across the FRS regions in any particular period and in any particular region from period-to-period (Table 19). From the 1990's until 2002, the highest and lowest regional finding costs year have differed from each other by $3.60 per barrel of oil equivalent (boe) to $11.90 per boe in constant 2002 dollars (Figure 28). The relatively high variance in regional finding costs is indicated by the extent that the range between the maximum and minimum finding costs has exceeded the lowest finding cost in every year except one. In addition, the gap between maximum and

minimum finding costs has been widening in recent years, largely because the maximum finding cost has increased much more than the minimum one.

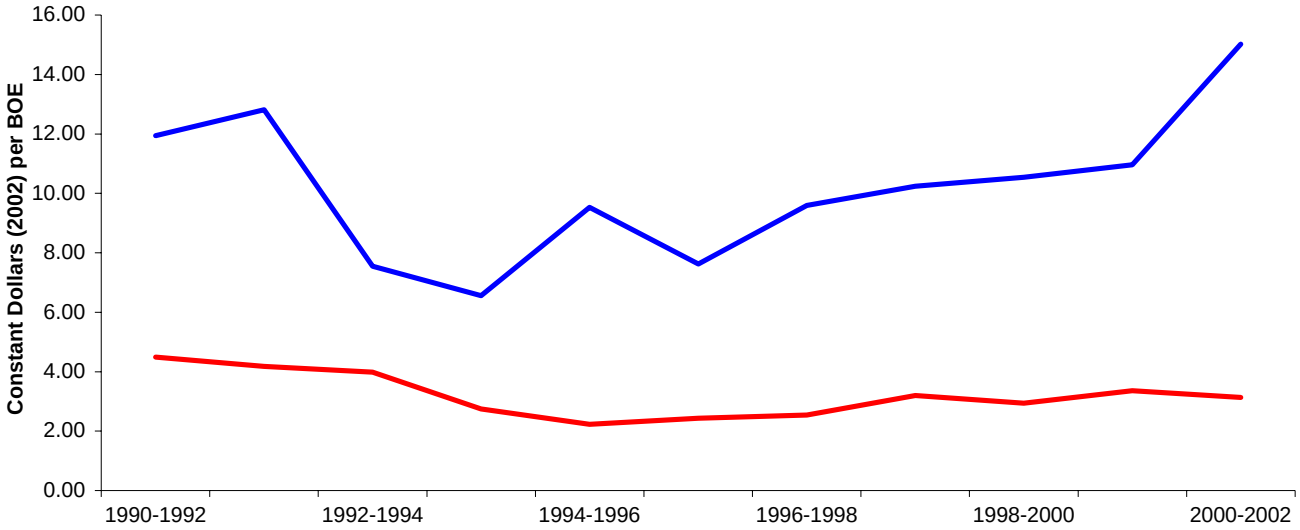
Nonetheless, when examining regional finding costs over a long period of time, many of the regions have had relatively consistent finding cost levels. (In this discussion of regional finding cost trends, five-year periods are being used to dampen extreme values and facilitate comparisons.) The regions can, somewhat arbitrarily, be separated into groups with high costs, low costs, and varying costs for the years 1990 through 2002 (Figure 29).

The regions that have had high finding costs are Canada, the U.S. Offshore (largely the Gulf of Mexico), and OECD Europe (largely the North Sea). Moreover, some of the largest finding cost increases in recent years have been incurred in these regions. With one of the lowest expenditures per well of any region, Canada might be expected to have low finding costs. However, most of Canada's oil and gas reserves tend to be in smaller pockets somewhat near to the surface, resulting in a majority of the wells in Canada being relatively shallow wells that are less costly to drill but also account for smaller reserve additions. Therefore, the low reserve additions per well results in Canada having one of the highest regional finding costs for the FRS companies. OECD Europe reserves are mostly offshore. Offshore exploration and development tends to be relatively more expensive, with larger fields found and lower lifting costs. This is part of the reason that the U.S. Offshore and OECD Europe are among the regions with the highest expenditures per well.

The low-cost regions from 1990 through 2002 are Africa, the Other Western Hemisphere, and the Other Eastern Hemisphere (Figure 29). All three regions fall in the middle range of the amount of exploration and development activity, both in spending and reserves added over the period. These regions differ from the other FRS regions because they are not as well developed as the U.S. Onshore and Offshore, Canada, and OECD Europe regions and generally have not restricted investment by U.S. companies as much as the two regions of the Middle East and the Former Soviet Union and Eastern Europe. The three low-cost regions also have had some of the most stable finding cost levels of any of the FRS regions.

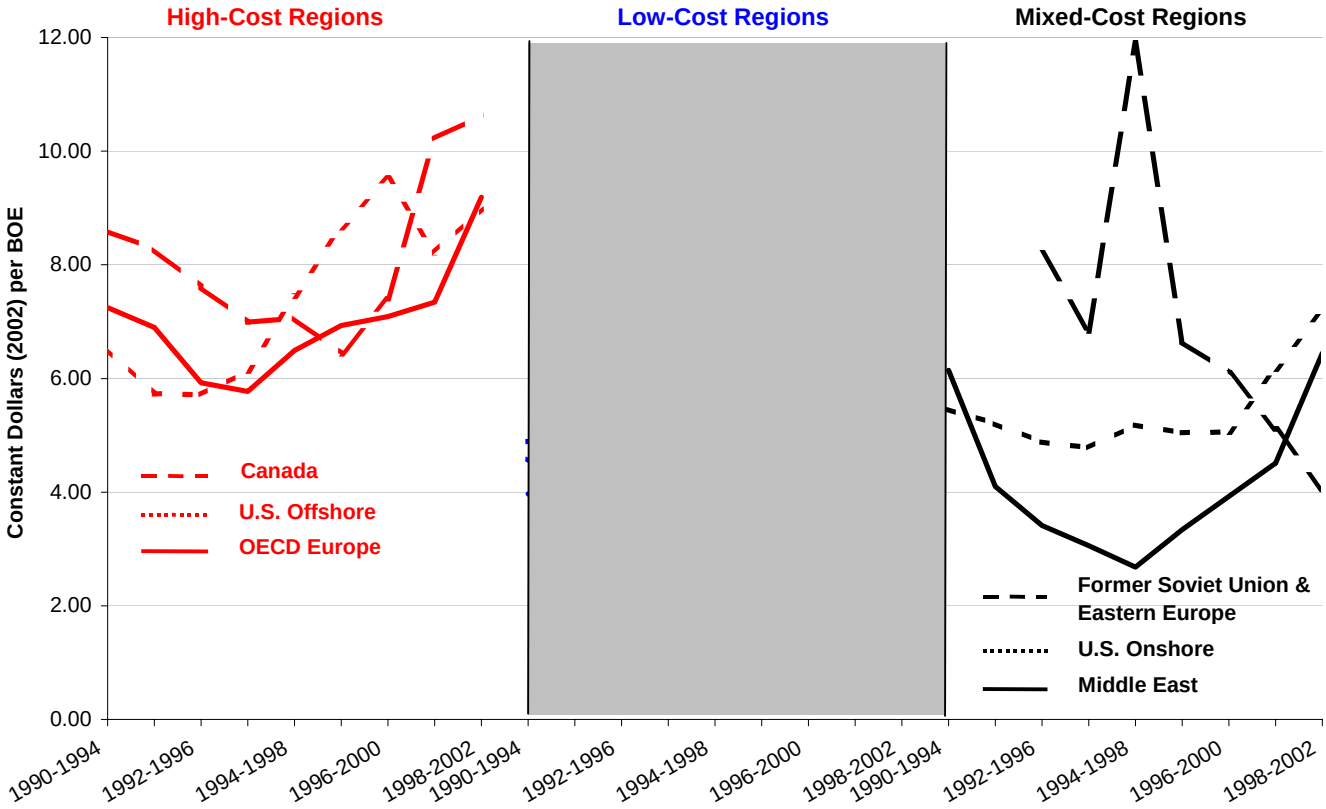
The remaining regions, the U.S. Onshore, the Middle East, and the Former Soviet Union and Eastern Europe, exhibit cost patterns that are not as consistent as the other FRS regions (Figure 29). Finding costs for the U.S. Onshore had remained rather stable and low, but they have increased substantially in both of the last two five-year periods, indicating the possibility that this region may become one of the high-cost ones.[e] Finding costs for the FRS companies in the Middle East have followed a "U-shaped" pattern, from high to low to high again, with increases in the last four five-year periods (a total timeframe of eight years). The cost estimates for this region are probably the most uncertain, because, as previously explained, the Middle East has had less exploration and development spending by the FRS companies than any other region by a large margin. The region of the Former Soviet Union and Eastern Europe had high finding costs in the middle of the period, but has experienced dramatic declines in eight-year period comprised by the last four five-year periods, as exploration and development activities has ramped up from very low levels in the early and mid-1990's.[f]

Figure 28. Maximum and Minimum Three-Year Weighted Average Regional Finding Costs for FRS Companies, 1990-1992 to 2000-2002



Note: Finding costs are weighted averages of the annual finding costs for the three years specified. The labels used on the horizontal axis reflect that the values plotted on the figure are 3-year averages.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Figure 29. Five-Year Weighted Average Regional Finding Costs for FRS Companies, 1990-1994 to 1998-2002



Note: Finding costs are weighted averages of the annual finding costs for the five years specified. The labels used on the horizontal axis reflect that the values plotted are 5-year averages. Finding costs for the Former Soviet Union and Eastern Europe are not available before 1992-1996 due to confidentially requirements.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Finding Costs Are Rising, But So Are Prices

Overall, finding costs have been rising above their lows of the mid-1990's, both domestically and abroad (Figure 30). However, U.S. Offshore finding costs, which had surged beginning in the three years of 1994 to 1996, have fallen back to meet the rising U.S. Onshore costs, while foreign costs have stayed lower than costs in the United States for the two most recent three-year periods.

However, trends in finding costs must be considered, among other things, in the context of oil and gas prices. Finding costs are expected to move in concert with crude oil and natural gas prices.[g] Higher crude oil and natural gas prices mean that crude oil and natural gas are worth more than they had been, so profit-seeking companies should be spending more to find them.

The prices of crude oil and natural gas declined through most of the 1980's, followed by a level period for natural gas and a slight decline for crude oil (Figure 31).[h] However, both have been rising in recent years. The trend in worldwide finding costs for the FRS companies has exhibited a similar pattern. Worldwide finding costs declined in the 1980's through mid-1990's, but then began rising. They have increased 42 percent since their low in the 1994 to 1996 period; over the same period, domestic crude oil prices rose by 39 percent and natural gas prices by 72 percent.

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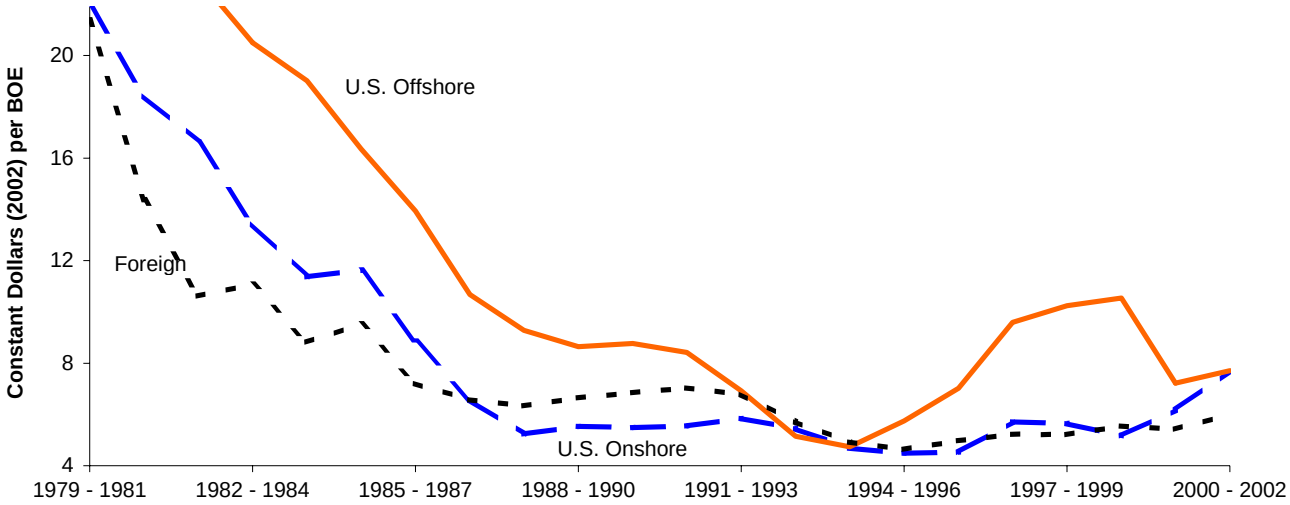
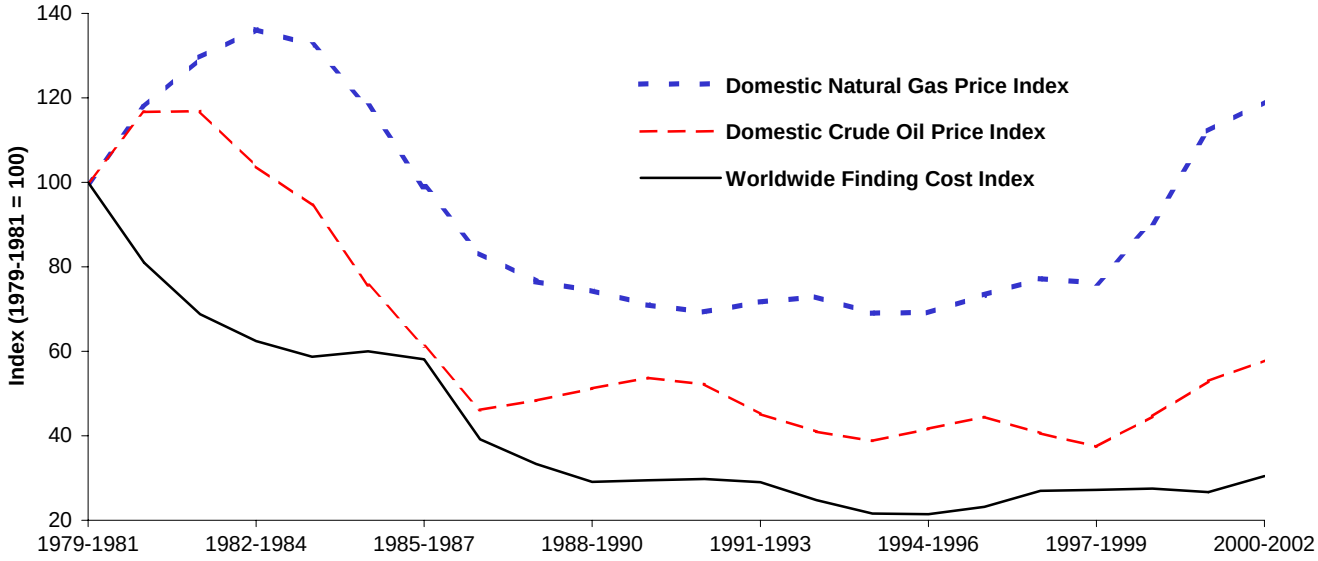
[a]Alternatively, finding costs are the exploration and development costs of replacing reserves removed through production.
[b]One inherent limitation of measuring finding costs this way is that the expenditures and the reserve additions recognized in a particular interval do not usually correspond exactly with each other. Expenditures are usually recognized in the period that the payment actually occurred. Proven reserves are usually recognized when there is reasonable certainty that they can be produced economically. There is no reason that these must occur in the same time period (oil and gas wells are often operated over a long time period), so that some expenditures may not be recognized in the same time period that their corresponding reserves are recognized. One way to moderate this limitation is to increase the length of the time period over which finding costs are measured, allowing reserve additions and exploration and development expenditures to match up more closely. However, the longer the time period over which finding costs are measured, the more out of date they become, because they include older and older expenditures and reserves, and costs and technology are constantly changing. The only way to solve the correspondence problem would be to calculate an average finding cost for all of the oil and gas produced by a well after it is permanently shut in. But then many costs included would be far out of date.
[c]As with finding costs, measurements of reserve additions per well are limited because the reserves added and the wells completed during a particular interval of time do not necessarily correspond exactly with each other. (For further discussion, see previous note.)
[d]If finding rates and expenditures either rise or fall by the same percentage, then finding costs will not change. (See Former Soviet Union and Eastern Europe Tables 19 and 20.)
[e]Every year, one year is added and one year is dropped from this calculation. The above result regarding finding costs for the U.S. Onshore region means that annual U.S. Onshore finding costs were higher in 2001 that in 1996, and higher in 2002 than in 1997.
[f]Five-year finding costs for the regions of the Former Soviet Union and Eastern Europe before the 1992 to 1996 period cannot be disclosed because of data confidentiality requirements.
[g]Technological change is another factor in determining finding costs; it is not considered in this discussion.
[h]The prices used to construct these indices are domestic prices. While the domestic price of crude oil is similar to the world price, the domestic price of natural gas is not. However, worldwide natural gas prices have moved in similar directions since the mid-1990's. See *BP Statistical Review of World Energy*, (London, United Kingdom, June 2003), p. 29.

Figure 30. U.S. Onshore, U.S. Offshore, and Foreign Three-Year Weighted Average Finding Costs for FRS Companies, 1979-1981 to 2000-2002



Note: Finding costs are weighted averages of the annual finding costs for the three years specified. The labels used on the horizontal axis reflect that the values plotted on the figure are 3-year averages.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Figure 31. Indices of Three-Year Average Domestic Real Prices of Crude Oil and Natural Gas and Worldwide Finding Costs for the FRS Companies, 1979-1981 to 2000-2002



Notes: Averages are unweighted. Real prices are in constant 2002 dollars. Crude oil price is the crude oil domestic first purchase price, and natural gas price is the domestic wellhead natural gas price. The labels used on the horizontal axis reflect that the values plotted on the figure are 3-year averages.
Source: Domestic natural gas price index and domestic crude oil price index: Energy Information Administration, *Monthly Energy Review October 2003,* DOE/EIA-0035(2003/10) (Washington, DC, October 2003), Tables 9.1 and 9.11. Worldwide finding cost index: Energy Information Administration, Form EIA-28 (Financial Reporting System).

SPECIAL TOPIC: The Gulf of Mexico – Do Technology and Recent Economics Favor Oil Reserves Over Natural Gas?

Exploration and development in the Gulf of Mexico commenced over fifty years ago when the Kerr-McGee corporation discovered Ship Shoal 32, about 10 miles off the Louisiana coast in 18 feet of water. By the mid-1980's, almost 1,000 fields had been discovered and many industry analysts were convinced that the Gulf was in decline.[a] Some even referred to the Gulf as the "Dead Sea."[b] Starting with Shell Oil's discovery of the 220-million-barrel deepwater Auger field in 1987, this view has been replaced with the recognition that the Gulf still has tremendous potential. What has been especially striking about the deepwater fields are the high productivity rates of the wells. For example, a typical shallow-water oil well flows at just over 100 barrels of oil per day, whereas oil wells at the deepwater Ursa field each produce about 30,000 barrels of oil per day.[c] Similarly, a single well at the deepwater Mensa field produces about 100 million cubic feet of gas per day, which is about fifty times the flow rate for a typical shallow-water gas well.[d]

In the shallow-water portion of the Gulf, i.e. that portion of Gulf where the water depth is less than 200 meters, the industry over the period of 1993 through 2002 replaced approximately 80 percent of the roughly 7.4 billion of crude oil equivalent that was produced over the period.[e] As a result, crude oil equivalent reserves in the shallow Gulf were approximately 33 percent lower at the end of 2002 than in 1993. Fortunately, this has been more than offset by the deepwater where reserve additions over the 1993 through 2002 period were more than 2.5 times the level of production.

For the Gulf as a whole, over 12 billion barrels of crude oil equivalent were produced over the period 1993 through 2002 while reserves at the end of 2002 were approximately 2.5 billion barrels of oil equivalent higher than at the beginning of the period.[f] With respect to remaining undiscovered resources, the 2000 resource assessment performed by the U.S. Department of Interior's Minerals Management Service (MMS) indicates that there are approximately 71 billion barrels of oil equivalent yet to be added to reserves.[g] Not surprisingly, the vast proportion of the remaining undiscovered resources are in the deepwater. MMS estimated that the split between oil versus natural gas resources is approximately fifty-fifty.[h]

Some of the more notable deepwater discoveries include:

Thunder Horse. This field (previously known as Crazy Horse) is believed to contain between one and three billion barrels of recoverable crude oil equivalent, which makes it the largest field ever discovered in the Gulf of Mexico.[i] This field gives new meaning to the notion of a deep field in that it lies over 25,000 feet below the ocean floor which in turn is 6,000 feet below the surface of the Gulf. The field also typifies the long lead-time associated with offshore exploration and development. Lead times can be long because production requires pipeline infrastructure that may only be economic when there are a number of fields to be brought onstream.

For example, in the case of Thunder Horse, the field was leased in 1988 but the first discovery well was not drilled until 1999. Initial production is expected to commence in 2005, 17 years after the lease was acquired.[j] It is expected to be worth the wait given that the field will be produced using a 250,000-barrels-of-oil-equivalent-per-day floating production facility. Partners in the field are BP (with a 75-percent ownership share) and Exxon Mobil (with a 25-percent ownership share). The field also typifies

the oil-prone nature of the deepwater discoveries to date based on the planned production facilities, approximately 87 percent of the production (on an oil equivalent basis) is expected to be accounted for by crude oil as compared to natural gas.[k]

Mad Dog. Discovered in 1998, the Mad Dog oil field development is planned to have 14 wells tied back to a spar. The facility is designed to process 87,000 barrels of oil equivalent per day.[l] Approximately 92 percent of the production is expected to be oil.[m] The first production of oil is expected by early 2005. Partners in the project are BP (with a 60.5-percent ownership share), BHP Billiton (with a 23.9-percent ownership share), and Unocal (with a 15.6-percent ownership share).

Na Kika. This project is located 140 miles southeast of New Orleans. It consists of five distinct fields with water depths of 5,800 to 7,000 feet.[n] In part because of a lack of pipeline infrastructure, the fields (while discovered in the 1980s) are only now being developed. The fields will be produced using 10 wells tied back to a centrally located floating production platform. The platform is a semi-submersible unit equipped with drilling and production equipment. It is anchored in place or can be dynamically positioned using thrusters. The facility is designed to process 190,000 barrels of oil equivalent per day with approximately 57 percent of the production being accounted for by oil.[o] Production is expected to commence in early 2004. Partners in the project are BP and Shell Oil. The partners have equal ownership interests in four of the five fields. BP has a majority stake in the fifth field.

Atlantis. This field is located 125 miles south of New Orleans in 4,400 to 7,100 feet of water.[p] The field will be developed with a moored semi-submersible production facility with a design capacity of around 180,000 barrels of oil equivalent per day. Less than 20 percent of the output is expected to be natural gas. BP is the operator and has a 56-percent ownership interest. BHP Billiton accounts for the remaining 44-percent ownership share.

All of the above projects will make use of the $1-billion Mardi Gras transportation system which upon completion will consist of five pipelines stretching more the 450 miles across the Gulf. This system will have the capability of transporting over 1 million barrels per day and 1.5 billion cubic feet day of crude oil and natural gas, respectively.[q]

Other recent significant discoveries includes Vortex (Kerr-McGee, BHP Billiton, and Ocean Energy), Tahiti (ChevronTexaco, PanCanadian Energy, and Enterprise), Deimos (Shell Oil and BP), and Great White (Shell Oil, BP, and ChevronTexaco). Only Vortex is known to be prone to natural gas.[r]

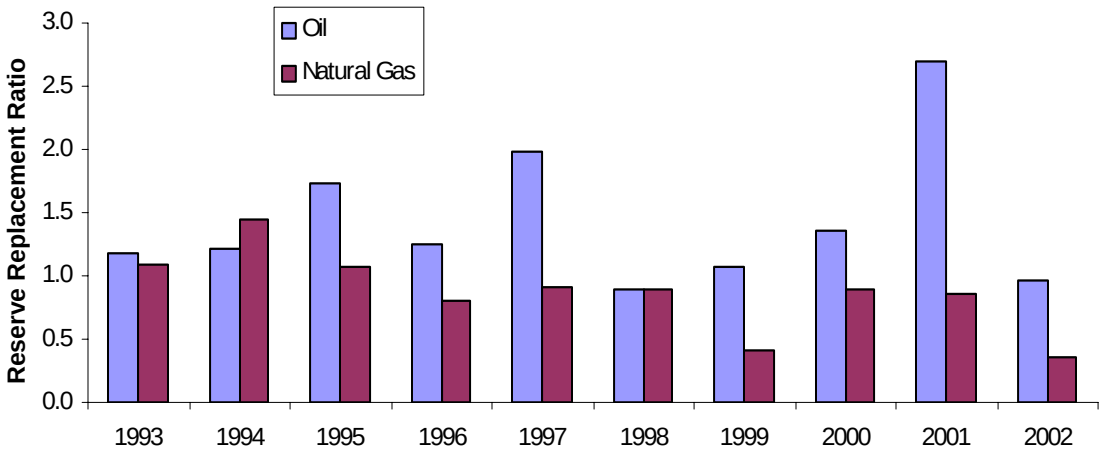
The oil-prone nature of these recent discoveries does not appear to be consistent with what one would expect based on MMS's fifty-fifty oil to natural gas resource assessment in 2000. It is also not consistent with the most recent 2003 MMS resource assessment which (according to *The Wall Street Journal*) significantly raised their estimate of the amount of undiscovered natural gas resources left in the Gulf.[s]

It may be the oil-prone nature of the projects currently being developed in the Gulf is a legacy of the industry's previous focus on finding and developing oil resources. Alternatively, this outcome could be attributed to the fact that many of the undiscovered gas prospects have a vertical drilling depth greater than 15,000 feet where the seismic imaging is poor relative to shallower drilling depths.

In any event, the relatively more oil versus natural gas being developed in the Gulf has major implications for domestic crude oil and natural gas supplies. Buoyed by these and other discoveries, the FRS companies have replaced over 100 percent of their offshore oil production in eight out of the past

ten years (Figure 32). For the period as a whole, the companies have replaced 145 percent of their offshore crude oil production. In contrast, the natural gas reserve replacement rate has exceeded 100 percent in only three of the past ten years. For the period as a whole, the natural gas reserve replacement rate was a disappointing 87 percent.[t] Additionally, this situation has deteriorated further in recent years. Over the 1998 through 2002 period, natural gas reserve additions were only about 70 percent of the amount of natural gas that was produced. Fortunately, continued improvement in seismic technology (in conjunction with the current price environment) should eventually yield the discovery of additional natural gas.

Figure 32. Reserve Replacement Ratios for the FRS Companies in the U.S. Offshore, 1993-2002



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

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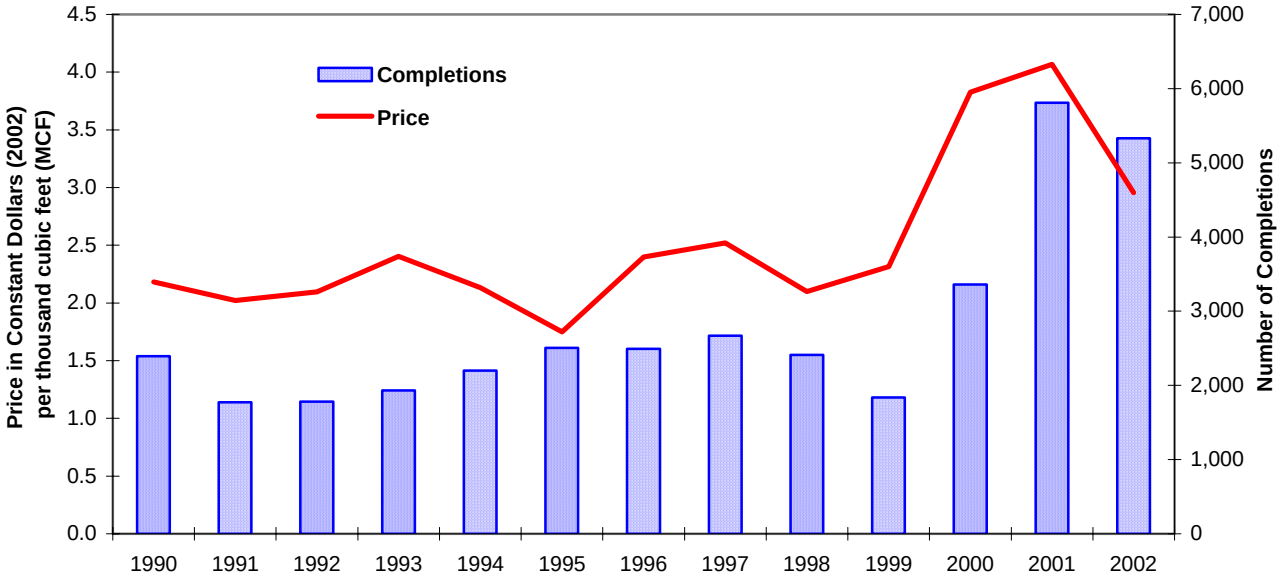
[a]Kallaur, Carolita, "The Deepwater Gulf of Mexico—Lessons Learned," Institute of Petroleum's International Conference on Deepwater Exploration and Production in Association with OGP, February 22, 2001 London, UK. Located on the Internet at http://www.gomr.mms.gov/homepg/offshore/deepwatr/lessons_learned.html (as of December 15, 2003).
[b]Ibid.
[c]Ibid.
[d]Ibid.
[e]Energy Information Administration, "Advanced Summary U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserve 2002 Annual Report," DOE/EIA-0216(2002) Advance Summary, October 2003.
[f]Minerals Management Service, "Outer Continental Shelf Petroleum Assessment 2000," September 2003. Located on the Internet at http://www.mms.gov/revaldiv/RedNatAssessment.htm (as of December 15, 2003).
[g]Ibid.
[h] Ibid.
[i] BP plc, "Upstream Build Projects," January 2003. Located on the Internet at http://www.bp.com/liveassets/bp_internet/globalbp/STAGING/global_assets/downloads/U/Upstream_build_projects.pdf (as of December 15, 2003).
[j]Ibid.
[k]Ibid. Based on the reported design capacities and the conversion factor of 0.178 mcf of natural gas per barrel of crude oil.
[l] Ibid.
[m]Ibid. Based on the reported design capacities and the conversion factor of 0.178 mcf of natural gas per barrel of crude oil.
[n] Ibid.
[o]Ibid. Based on the reported design capacities and the conversion factor of 0.178 mcf of natural gas per barrel of crude oil.
[p] Ibid.
[q]Ibid.
[r]"BHP Billiton Discovers Natural Gas with Vortex-1 Well in Deepwater Gulf of Mexico," Oil & Gas Journal Online, (December 13, 2002). Located on the Internet at http://ogj.pennnet.com/articles/web_article_display.cfm?Section=Archives&Article_Category=ExplD&ARTICLE_ID=163772&KEYWORD=vortex (as of December 15, 2003)
[s]Gold, Russell, " Gulf of Mexico May Hold More Natural-Gas Supply," *The Wall Street Journal* (November 19, 2003).
[t]Energy Information Administration, Form EIA-28 (Financial Reporting System).

SPECIAL TOPIC: Natural Gas Supply -- A New Paradigm?

Throughout most of the 1990's, many natural gas analysts were of the view that technological progress would enable the North American natural gas supply industry to meet growing demand at moderate to low prices. According to the Energy Information Administration, the natural gas price in 1999[a] was $2.19 per thousand cubic feet while the natural gas price for 2003[b] was projected (in December 2003) to be $4.97 per thousand cubic feet, a 127-percent increase over the period. However, despite these higher prices, natural gas production in 2003 was projected (in December 2003) to be only about 3.6 percent higher than in 1999.[c] This seemingly inelastic response of production with respect to price has led some to question whether technology advances will in fact be robust enough to keep natural gas prices at moderate to low levels. In other words, is a new natural gas supply paradigm – one of higher prices being needed to meet projected demand – emerging? For instance, the National Petroleum Council (NPC) has recently concluded that current North American producing areas and those under development will be unable to meet projected demand over the next 20 years.[d]

At first glance, the NPC's concerns appear to be misplaced. Producers such as the FRS companies have responded to the increase in the price of natural gas by substantially increasing their level of drilling for natural gas (Figure 33). Domestic gas well completions by the FRS companies attained an all-time high in 2001. While completions were off in 2002, they were nevertheless almost three times their level in 1999.

Figure 33. The Domestic Wellhead Price of Natural Gas and the Number of Domestic Gas Well Completions by the FRS Companies, 1990-2002

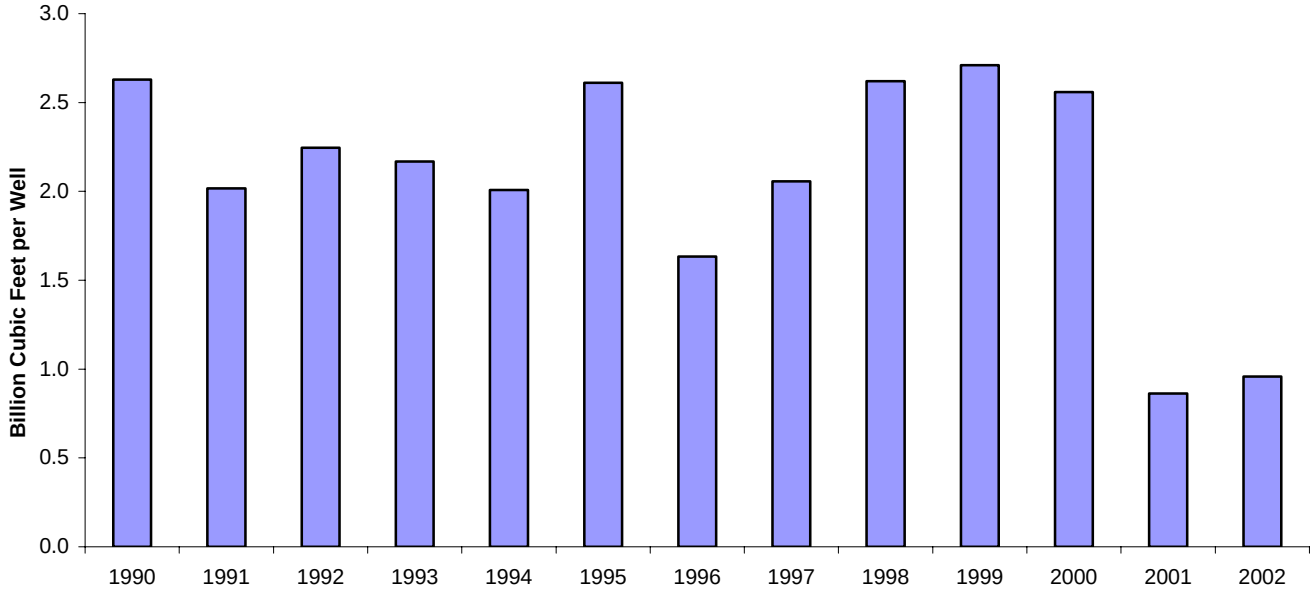


Sources: Energy Information Administration, Form EIA-28 (Financial Reporting System) and Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130(2003/10) (Washington, DC, October 2003).

The possibility of a paradigm shift becomes more apparent if one examines the volume of gas added to reserves by the average successful gas well. Over the period of 1990 through 2000, the FRS companies drilled 23,367 gas wells in the onshore United States. This drilling yielded approximately 54,903 billion

cubic feet of reserve additions (extensions and discoveries plus reserve additions associated with improved recovery plus reserve revisions), which means that the average onshore gas well added approximately 2.3 billion cubic feet of natural gas to proved reserves.[e] In sharp contrast, reserve additions per well in 2001 and 2002 were about 1 billion cubic feet (Figure 34). A portion of the decline can be attributed to a change in the type of wells drilled. Approximately 90 percent of the onshore gas wells that the FRS companies drilled over the period of 1990 through 2000 were developmental wells.[f] Relative to exploratory wells, developmental wells do not add much to reserves but instead extract gas out of already proved reserves. In the 2000 through 2001 time period, the share of wells classified as developmental was over 95 percent. Whether this shift in the mix of drilling explains the entire decline in reserves added per well is the fundamental natural gas supply question.

Figure 34. Natural Gas Reserve Additions per Well for FRS Companies in U.S. Onshore, 1990-2002



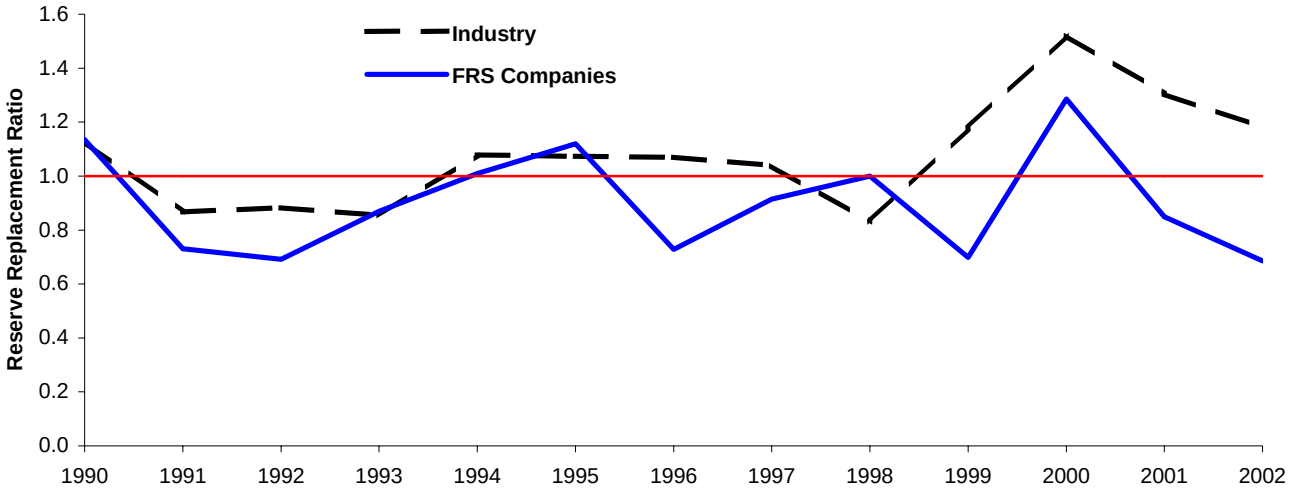
Notes: The numerator of reserves additions per well includes revisions, improved recovery, and extensions and discoveries. The denominator includes both exploratory and developmental successful gas wells.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Nonetheless, the NPC's concern about the adequacy of the natural gas supply becomes almost impossible to dismiss if one examines the reserve replacement rate. This statistic is the ratio of reserve additions to production. (A ratio greater than one indicates that exploration and development efforts are adding more to reserves than the firms are withdrawing from reserves.[g] A ratio less than one indicates that the exploration and development efforts are adding less to reserves than the amounts that the firms are producing from reserves.[h]) The domestic natural gas reserve replacement rate for the FRS companies over the period of 1990 through 2002 was less than 1.0 in 9 out of the 13 years (Figure 35). For the entire period, the companies replaced only about 90 percent of production. For the industry as a whole, the situation is less grim. The domestic natural gas reserve replacement rate for the industry over the period of 1990 through 2002 was greater than 1 in 9 out of the previous 13 years.[i] For the period of 1990 through 2002 as a whole, the industry has replaced 108 percent of production. While this latter statistic does provide some grounds for natural gas supply optimism, it should be understood within the context of a declining extraction rate.

The extraction rate, which is the ratio of production to reserves, increased over the early part of the 1990's for both the FRS companies and the industry as a whole (Figure 36). Over the past few years,

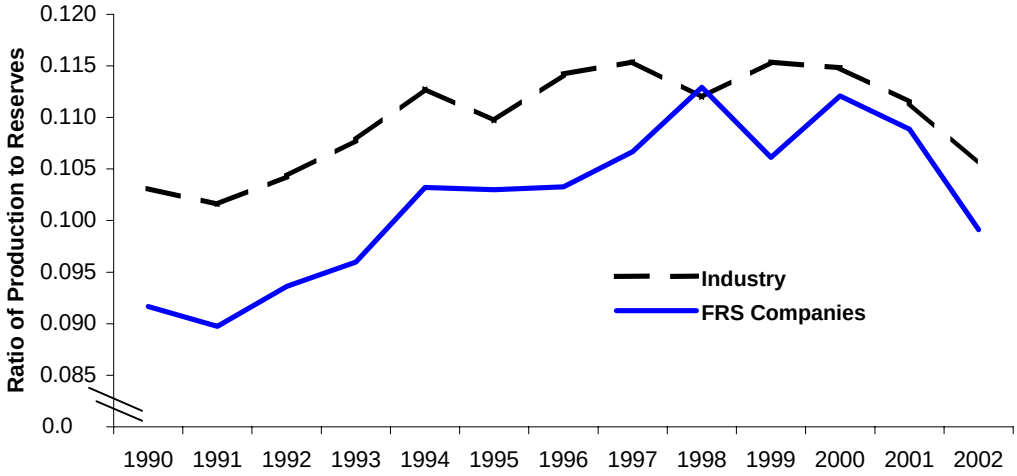
however, the ratio has declined for both groups. Indicative of the significance of the decline, the domestic natural gas production of the FRS companies in 2002 would have been 616 billion cubic feet higher had the production to reserves ratio in 2002 been equal to its 1999 value. For the industry as a whole, production would have been 1.8 trillion cubic feet higher.

Figure 35. The Domestic Natural Gas Reserve Replacement Ratio for the FRS Companies and the Domestic Natural Gas Supply Industry as a Whole, 1990-2002



Sources: Energy Information Administration, Form EIA-28 (Financial Reporting System) and Energy Information Administration, *Advanced Summary U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserve 2002 Annual Report* , DOE/EIA-0216(2002) Advance Summary (Washington, DC, October 2003).

Figure 36. The Ratio of Natural Gas Production to Proved Natural Gas Reserves for the FRS Companies and the Domestic Natural Gas Supply Industry, 1990-2002.



Source: Sources: Energy Information Administration, Form EIA-28 (Financial Reporting System) and Energy Information Administration, *Advanced Summary U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserve 2002 Annual Report* , DOE/EIA-0216(2002) Advance Summary (Washington, DC, October 2003).

The recent decline in the production to reserves ratio can be partly attributed to an increase in non-producing reserves as firms commence drilling in areas where there may be a lack of pipeline infrastructure (such as in frontier areas of the Rocky Mountains). Another factor contributing to the decline is the increased emphasis on unconventional gas sources such as coalbed methane, tight sands, and gas shales.[j] As recently as 1996, less than 40 percent of onshore reserve additions were accounted

for by unconventional sources; the comparable figure for 2000, the latest year for which reliable data are available, is 67 percent.[k] As compared to conventional natural gas wells, unconventional wells typically have lower daily production rates, which translate into a smaller amount of production for a given reserve base. For example, in 2000, the extraction rate for tight gas was almost 25 lower per unit of reserves as compared to conventional gas.[l] Given that unconventional gas is expected to become an even larger component of gas supply in the future,[m] the lower extraction rate that both the FRS companies and the industry as whole have experienced over the past few years may become a permanent fixture in the gas supply paradigm.

[a]Energy Information Administration, *Natural Gas Annual 1999*, DOE/EIA-0131(99) (Washington DC, October 2000).
[b]Energy Information Administration, *Short-Term Energy Outlook*, December 2003, http://www.eia.doe.gov/emeu/steo/pub/contents.html (as of December 16, 2003).
[c]Ibid.
[d]The NPC report is available at http://npc.org
[e]Energy Information Administration, Form EIA-28 (Financial Reporting System).
[f]Ibid.
[g]Remaining reserves rise as a result, which enables production to also rise (for a given extraction rate).
[h]Remaining reserves decline as a result, which allows production to also decline (for a given extraction rate).
[i]Energy Information Administration, *Advanced Summary U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserve 2002 Annual Report*, DOE/EIA-0216(2002) Advance Summary, October 2003.
[j]For additional information on the production of natural gas as coalbed methane, see Energy Information Administration, *Performance Profiles of Major Energy Producers 2000*, DOE/EIA-0206(2000) (January 2002, Washington, DC), pp. 79-83. Available on the Internet at http://tonto.eia.doe.gov/FTPROOT/financial/020600.pdf (as of December 16, 2003).
[k]Special compilation by the Energy Information Administration, Office of Integrated Analysis and Forecasting.
[l]Ibid.
[m]Energy Information Administration, *Annual Energy Outlook 2004*, DOE/EIA-0383(2004) (Washington DC, January 2004).

SPECIAL TOPIC: Canada's Mackenzie Delta -- One Part of Future Natural Gas Supply?

Natural gas prices are now over twice what they were in the late 1990's[a]. Some, such as Federal Reserve Chairman Alan Greenspan, see imported liquefied natural gas (LNG) as the solution to this problem.[b] While not dismissing the importance of LNG, others point out that North America has a substantial quantity of stranded gas reserves -- gas that could be marketed if there were a low-cost mechanism of transporting the gas to market. For instance, the Mackenzie Delta in Canada's Northwest Territories contains over 10 trillion cubic (tcf) feet of known recoverable natural gas.[c] This is the volume of gas that had been booked as reserves during the 1970's; however, like the natural gas on Alaska's North Slope, this gas was never produced because of a lack of pipeline infrastructure that could move the gas to market. In 1994, the Mackenzie Delta gas reserves were written off the books (by those companies owning the gas) when the price of gas in Canada sold for an equivalent of approximately $1.50 (U.S.) per thousand cubic feet (Mcf).[d] A year earlier, over 14 tcf of gas located in Canada's Artic Islands (located northeast of the Mackenzie Delta) was also written off given its remote location.[e]

Recently, Imperial Oil (Canada's largest oil company, 69.6-percent owned by the FRS company Exxon Mobil), ConocoPhillips, Exxon Mobil, and Shell Canada (a wholly owned subsidiary of the British Royal Dutch Shell) have formed the Mackenzie Gas Producers Group with the aim of developing the natural gas fields and constructing a pipeline system along the Mackenzie Valley. This system would deliver the gas to Northwestern Alberta where existing pipelines could then move the gas to other parts of Canada as well as to the United States.[f] The goal is to have the natural gas moving through the pipeline by 2010. The pipeline is planned to have a 1.2-billion-cubic-feet-per-day (bcf/d) initial capacity that could be expanded to 1.9 bcf/d by adding additional compression stations. The overall cost of the project including the construction costs of the pipeline, the gathering system, and required field development is estimated at $4 to 5 billion (in Canadian dollars), which is approximately $3 to 3.8 billion (in U.S. dollars).

A large portion of the gas for the pipeline is expected to come from three major fields:

Taglu. This field has estimated recoverable natural gas resources of 3 tcf. Imperial Oil Limited has a 100-percent interest in the field. Imperial will also have an interest in the gathering lines as well as in the pipeline system.

Parsons Lake. This field has estimated recoverable natural gas resources of 1.8 tcf. Partners in this field are the FRS companies ConocoPhillips (with a 75-percent ownership share) and Exxon Mobil (with a 25-percent ownership share).

Nglintgak. This field was discovered in 1973 and has estimated recoverable natural gas resources of approximately 1 tcf. The field is owned by Shell Canada. Because of the high productivity of the wells in terms of output per day, it is believed that the field can be developed using only about 6 to 10 wells.

In addition to the Producers Group, the Aboriginal Pipeline Group (APG) will also have an interest in the pipeline portion of the project. The APG was formed in 2000 to represent the interests of the aboriginal people of the Northwest Territories in the project. The APG has signed a "Memorandum of Understanding" with the Mackenzie Gas Producers Group that gives APG the right, depending on the throughput of the pipeline, to own up to one-third of it. Also, as part of the Memorandum, TransCanada (a Canadian pipeline company) will lend approximately $80 million (in Canadian dollars), which is approximately $60 million in U.S. dollars to the APG to finance APG's share of the project planning costs. The APG expects to finance the vast proportion of its share of the pipeline construction costs by borrowing against its share of future pipeline revenues. However, it is far from clear that these loans will be sufficient to fund the entire amount of APG's commitment.

Other companies active in the Mackenzie Delta include Devon Energy and Petro-Canada (a major Canadian integrated oil and gas company), which together hold leases on more than 1 million acres of land. Over the last two winters, the two firms drilled three unsuccessful exploratory wells -- Kurk M-15, Tuk B-02, and Kugpik L-46. While hydrocarbons were encountered at Tuk B-02, the well was subsequently determined to be uneconomic. More recently, the partners have announced that a fourth exploratory well, Tuk M-18, has yielded significant gas flows. The well is estimated to have a reserve potential of 200 to 300 bcf with a sustained deliverability of 60 to 80 mcf/d.[h]

While it is increasingly likely that the Mackenzie Delta project will become a reality, it is far from clear how much of the gas will ultimately reach U.S. markets. It may be that much of the gas will be used by Canada's expanding oil sands (synthetic crude) industry. The in situ oil sands projects in Canada use natural gas to create steam that enables the bitumen hydrocarbons to flow to the surface. According to

Canada's National Energy Board, one of the most promising in situ technologies, Steam Assisted Gravity Drainage (SAGD), requires 1 mcf of gas for every barrel of bitumen that is produced.[i] Given these gas requirements, it is not surprising that one study has recently concluded that the incremental gas demand from the oil sands projects could equal or even exceed the initial planned capacity of the MacKenzie Delta pipeline.

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[a]Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130(2003/10) (October 2003, Washington, DC).
[b]"Natural Gas Outlook Worries Greenspan," *New York Times*, (June 11, 2003), p. C4.
[c]Canadian Association of Petroleum Producers, *Statistical Handbook for Canada's Upstream Petroleum Industry, 2002*, Table 2-13A.
[d] Ibid..Table 5-06A.
[e]Ibid. Table 2-13A.
[f]Canadian Association of Petroleum Producers, "Canadian Natural Gas Overview," April 2003.
This document is available in the Internet at
http://www.capp.ca/Pandell_Docs_File_Streamer/IndependantFileRelayDirectFromDocs.asp?XXX=1&doctype=NTV&docnumber=56189 (as of December 15, 2003).
[g]This information is based on the project's preliminary information package which is available on the Internet at http://www.mackenziegasproject.com/theProject/regulatoryProcess/pipSubmission/Documents/Volume%202%20PIP.pdf (as of December 15, 2003).
[h]"Exploration and Development: Canada," *Oil & Gas Journal Online*, January 24, 2003. Available on the Internet at http://ogj.pennnet.com/articles/web_article_display.cfm?Section=Archives&Article_Category=ExplD&ARTICLE_ID=166830&KEYWORD=Tuk%20M%2D18 (as of December 15, 2003).
[i]"No Relief from Mackenzie gas: Lehman Brothers report says Delta Gas will likely all go to Oil Sands," *Petroleum News*, September 14, 2003.