U.S. Oil Production: The Effect of Low Oil Prices

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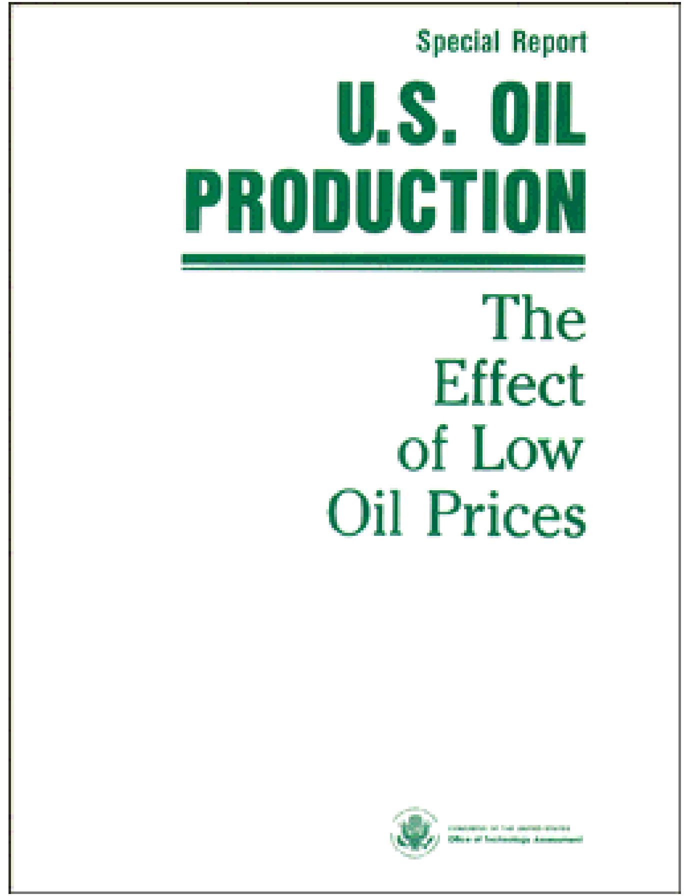

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Foreword

This special report responds to requests by the Government Operations Committee, the Energy and Commerce Committee, and the Subcommittee on Energy and Power of the House of Representatives for a review of the effect of volatile oil prices on U.S. domestic oil production. The review was conducted as part of OTA's ongoing assessment on *Technological Risks and Opportunities for U.S. Energy Supply and Demand.*

Congress' attention became focused on U.S. domestic oil production as a result of the largely unexpected plunge in world oil prices that began in December 1985. The price plunge began when Saudi Arabia attempted to recapture lost oil markets by increasing production and offering new and more attractive contract terms, throwing world oil supply and demand out of balance. One effect of the lower prices—which dropped from $28 per barrel in 1985 to below $15 per barrel for much of 1986—was to quickly force a portion of existing U.S. production out of service and to sharply reduce drilling and other exploration and production-oriented activity, guaranteeing that U.S. production would decline still further in the future. The Department of Energy and others have projected that the decline in production, coupled with increases in (price-sensitive) oil demand, will drive U.S. oil imports past the 50 percent mark by the early 1990s at the latest. Congress asked OTA to provide an independent assessment of these postulated effects.

This special report presents the results of OTA's analyses of a group of factors we believe will strongly influence the future direction of U.S. oil production. These factors include the expected profitability of new investments in drilling, the potential of new oil exploration, development, and production technologies, the nature of the remaining oil resource base, and structural changes in the oil industry. The special report also provides a brief discussion of some policy options for Congress to consider if it decides to moderate the expected accelerated decline in U.S. oil production.

OTA is indebted to the numerous individuals who contributed substantial time to this special report, providing information and advice and reviewing drafts. Also, the contributions of our colleagues in the Congressional Research Service, who provided analyses in two key areas, are gratefully acknowledged.

John H. Gibbons

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Summary

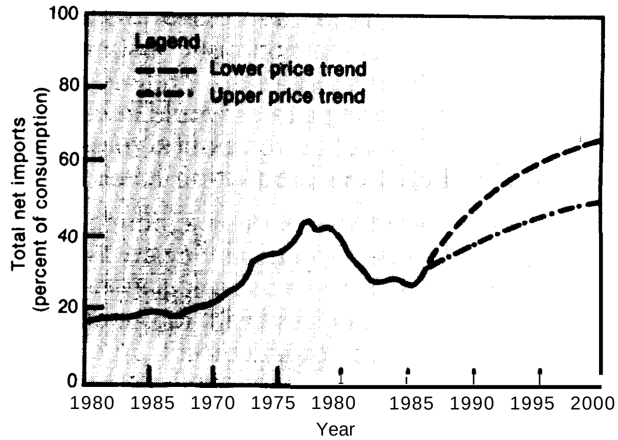
Overview and Findings

The recent precipitous drop in world oil prices from about *$28* per barrel ($28/bbl) in 1985 to between $12 and $18/bbl through much of 1986 dealt the U.S. oil industry a severe blow. In the first year after the price drop, U.S. crude oil production dropped by nearly 700,000 bbl/day, industry capital spending on exploration and production dropped from about $33 billion/year to about $16 billion, drilling activity dropped from over *70,000 well* completions/year to approximately 37,000, and the basic infrastructure of the industry, including its skilled personnel, shrank considerably. There is now a strong consensus that domestic oil production will continue to drop, to between 6 million and a bit over 7 million barrels per day (mmbd) by 1990, down from the 1985 level of 9 mmbd, if oil prices remain in the $12 to $18/bbl range.

A substantial drop in U.S. oil production is only one component of a chain of events . . . resulting from lower world oil prices . . . that could create future problems for the United States' economic stability and national security. First, this Nation's price-sensitive demand for oil will rise as its oil production declines—a combination resulting in a sharp increase in the level of imported oil. Most industry projections of the effects of continued low oil prices envision imports reaching 50 percent of U.S. oil consumption by the early 1990s or before. (Figure 1 shows the National Petroleum Council's import projections for a low and high price track.) At an oil price of $18/bbl, this will amount to a 50 to 60 billion dollar per year drain on the United States' balance of payments.

Simultaneously, similar trends in oil supply and demand will be occurring outside the United States. Lower oil prices are expected to depress oil production outside of the Organization of Petroleum Exporting Countries (OPEC) and the Middle East while increasing the worldwide demand

Figure 1.—Net U.S. Oil Imports As a Percentage of Oil Consumption, As Projected by the National Petroleum Council



Refiner acquisition cost of crude oil, 1986$	1985	1990	1995	2000
Lower price trend	27	14	17	21
Upper price trend	27	22	28	36

SOURCE: National Petroleum Council, *Factors Affecting U.S. Oil &* Gas *Outlook,* February 1987.

for oil (except where higher taxes maintain prices at previous levels). These changes will increase OPEC's share of the world oil market, with much of the increase going to the Middle Eastern OPEC nations. In time, the Middle Eastern OPEC producers will have returned to the levels of market share and production capacity utilization that in the past allowed them to affect prices or disrupt oil markets. And, thus, they will have regained an ability to upset U.S. economic stability and national security.

OTA's evaluation of a set of factors affecting future U.S. oil production lead to the following conclusions:

1. The available evidence points strongly to a continuing, and substantial, decline in U.S. oil

production if oil prices remain in the $12 to $18/bbl range. This evidence includes: a) recent production trends and trends in drilling and other oilfield activity; b) the financial state of the industry; c) industry surveys of future oilfield investment; d) the results of oil supply models; and e) a limited amount of economic analysis.

2. Recent rates of drilling activity are much too low to allow domestic oil production to stabilize close to today's already depressed production levels. Even with quite optimistic assumptions about the productivity of future drilling, a continuation of 1986 drilling rates would lower year *2000* U.S. oil production to about 6 mmbd– a third lower than 1985 production levels.

3. Available estimates of the magnitude of the production decline should be viewed as "best guesses" rather than as precise calculations, even if the uncertainty associated with future oil price levels is disregarded. Most current production forecasts assume implicitly or explicitly that previous trends and relationships established over the past few decades will continue into the future. The severity of the economic dislocations caused by the recent drop in oil prices, coupled with major changes in the industry over the past few years, imply that this assumption deserves to be reexamined. It is probably prudent to assume that the oil industry will adapt in various ways to the new economic environment and, in adapting, will break with many past trends.

4. It is not clear whether a break with past trends would lead to production levels higher or lower than an analysis based on historical behavior would predict. On the optimistic side, the oil industry might be expected to follow an initial period of disrupted operations with movement to more efficient management and positive technological adaptations. On the pessimistic side, any positive effects on oil production levels associated with an adaptive move to higher efficiency might be offset by several factors:

- the industry's higher debt levels caused by the wave of takeovers and mergers during the 1980s, which could depress total exploration and development (E&D) investment;
- the improvement in financial terms offered by several potential overseas producing countries, which might shift E&D investment out of the U. S.;
- the current drop in spending on research and development, which could slow technological innovation; and
- the apparent shift in basic industry E&D investment strategy, downplaying the importance of replacing company reserves and stressing the requirement that E&D investments satisfy rigorous profitability requirements.

There is no ready way to estimate the net effect on production of these diverse factors, Also, further uncertainty is added to estimates of future production levels by the dependence of production on a number of other factors that are not known with any precision, such as the magnitude, geographic distribution, and physical nature of remaining oil resources. Finally, uncertainty is added by the relatively low priority that appears to have been given to publicly ***available*** analysis of the economic attractiveness of new investment in drilling and other production-oriented ventures (the oil industry conducts extensive economic analysis of new investment prospects, but most of the analyses are proprietary and not available to assist in the public policymaking process). The attractiveness of such investment is the key indicator of long-term prospects for adequate U.S. reserve replacement and production.

If oil prices do stay low–perhaps averaging between $14 and $16/bbl for the next several years—what might be the outcome for domestic oil production? With rapid restructuring of the weaker companies, favorable adjustments in E&D strategies, innovation in E&D technology, and favorable potential for continued reserve growth in older oilfields, domestic production might be able to hold above 7 mmbd through 1990 (the upper end of the range of most industry estimates) and drop less steeply than projected thereafter. For the period beyond the early 1990s, the opening of Federal and State lands to exploration and the successful discovery of large oilfields on these lands could be of special importance. On the other hand, if the industry continues to shift to more overseas investment and fails to improve efficiency further, technological change slows because of reduced R&D spending, and reserve additions from older fields slow because of reduced geologic potential and poor economics, production could sink to the lower end of the consensus range (about 6 mmbd) in 1990 and conceivably even below the expected range in later years.

5. Further economic and technical analysis could be useful to policy makers concerned with falling oil production. With or without such analysis, however, substantial uncertainty will remain about how domestic production will respond to different price levels and policy environments, and policy makers must be prepared to make key decisions without precise knowledge of their outcomes. Some questions that cannot be fully answered with further analysis include:

- How will industry investment behavior adapt to the new price environment and to a changing business environment overseas?
- To what extent will the major industry restructuring of the 1980s eventually lead to higher efficiency and increased interest in new domestic E&D ventures? Will newly merged and restructured companies be able to eliminate their heavy debt burdens within a few years, and will they then act to boost their investment in traditional E&D activities?
- To what extent will technological change act to offset some of the negative effects on profitability of lower oil prices?
- Will relatively low cost drilling in the United States' older oilfields continue to provide large volumes of new reserves, or did the intensive drilling of the past decade essentially "use up" most of these fields' remaining growth potential?
- If large new blocks of Federal and State land are made available for exploration, especially offshore California and in the Arctic, will super giant fields be discovered and developed?
- How long will it take (or what conditions are necessary) to restore enough confidence to potential investors in E&D that they will respond readily to reasonable profitability prospects? To what extent could investment levels rebound without a concurrent rebound in cash flow from the industry's past investments?

6. There are ways to reduce, though certainly not eliminate, uncertainty about the magnitude of a future production decline and the potential effect on production of alternative government policy measures. Of most value would be a comprehensive analysis of the prospective profitability and productivity of new investment in oil exploration and development. Although some valuable economic analyses are available (e. g., the National Petroleum Council's evaluation of Enhanced Oil Recovery) these are too limited in scope and uncoordinated to qualify for the type of comprehensive analysis needed for careful forecasting and policy analysis.

Other potentially useful analyses include:

- A cataloging and analysis of changes in the business environment for oil and gas investment overseas.
- An evaluation of the dissemination and use of new technologies in oil exploration, development, and production during the past decade, and an examination of new technologies just introduced or on the near horizon.
- An economic analysis of existing oil production with high operating costs (especially stripper production), incorporating collection of physical and economic data at the individual well level.
- An examination of the differences in individual companies' E&D strategies and results, to gain further perspective about the potential for industry wide improvements in E&D efficiency.

7. Congress is faced with difficult choices, not only in 'selecting policies to combat trends towards lower domestic oil production and higher imports but also in deciding whether an active government role is wise. Unfortunately, some of the key issues associated with choosing an appropriate government role are ambiguous. For example, earlier concerns about the effect of higher oil imports on U.S. economic stability and national security have been complicated—but not negated–by the significant changes in oil markets and government preparation for market disruptions since the early 1970s. These changes include the construction of the Strategic Petroleum Reserve, the advent of a strong spot

market for crude oil, the beginning of a futures market, and substantial changes in the role of oil in the U.S. economy.

Another complication is that the majority of production forecasts prior to the 1985-86 oil price drop projected domestic oil production to begin falling rapidly in the 199os; in other words, most forecasters expected the production decline and subsequent increase in imports to occur even in the absence of a large price drop, albeit a decade later. At first glance, these predictions would appear to favor a "hands off" policy on oil production since boosting production today would appear to be only delaying the inevitable. Not al l forecasters agree with this "conventional wisdom," however; they contend that U.S. production could have been maintained, had prices not tumbled, with continued intensive field growth and innovation in enhanced oil recovery. Further, "buying" an extra decade of moderate import levels could be worthwhile **if** the decade were used to add flexibility and security to the U.S. energy system, rather than to artificially preserve the status quo, so that the Nation would be better prepared to deal with higher import levels when they occurred.

There is also uncertainty about whether allowing U.S. oil production to decline now might yield higher future production rates than would be possible if today's production rates were propped up and the resource base depleted more intensively. Although resource depletion is a valid concept, the remaining U.S. petroleum resource base is less a small resource than it is a low-grade resource whose recovery is amenable to improved technology. Thus, the pace of technology development—likely to be more rapid if production is kept high by tax or other incentives—conceivably may outweigh resource depletion as an influence on future production levels.

If Congress does decide to work to stabilize domestic oil production, it can use a number of policy mechanisms. The following options are discussed briefly in the report:

- oil import fees (either to raise wellhead prices or to establish a price floor);
- tax concessions (including investment tax credits, depletion allowances, cuts in severance and ad valorem taxes, drilling credits, abolishing the Windfall Profits Tax);
- removing the ban on oil exports from the Alaskan North Slope;
- bolstering investment in oil exploration and development R&D; and
- removing leasing restrictions on frontier/offshore areas.

Introduction

The long price slide that took world oil prices from about $40/bbl in 1981 to $28/bbl in December, 1985, and then precipitously downward to the $12 to $15/bbl level throughout much of 1986 has created a depression in the U.S. oil industry. Most indicators of the level of oilfield activity have been slipping since the "peak" year of 1981 and dropped sharply in the early months of 1986:

- The number of rotary drilling rigs working in the United States dropped from over 4,000 in 1981 to about 1,900 in July 1985 to below 700 a year later; they have since rebounded slightly.
- Industry employment dropped from a 1982 high of 708,000 to 585,000 in 1985 and to 422,000 in September 1986, with oilfield service employees bearing the brunt of the drop.
- Total well completions, which had declined moderately from 89,000 in 1981 to 73,000 in 1985, dropped below 40,000 in 1986. Figure 2 illustrates the rise and fall of well completions between 1970 and the present.
- The monthly seismic crew count, that is, the number of teams doing seismic surveys for oil and gas exploration and development, fell from 681 in 1981 to 378 in 1985 and to 195 in 1986.

U.S. oil production has slid from 9.03 million barrels per day (mmbd) at the end of 1985 to 8.35 mmbd a year later, a decline of over 7 percent. Coupled with increased oil demand, the production decline has forced U.S. net imports of crude

[1]That is, crude oi l plus ' ' lease condensates, ' natural gas l iq u ids recovered in the field. Total domestically produced petroleum also includes natural gas liquids recovered from gas processing plants, refinery processing gain, and small amounts of alcohol.

Box A.—Recent Studies by the National Petroleum Council and the Department of Energy

The National Petroleum Council (N PC) and the U.S. Department of Energy (DOE) have recently published reports on U.S. energy supply: Factors *Affecting U.S. Oil & Gas Outlook* and Energy *Security,* respectively. Both reports focus particularly on domestic oil production but also evaluate U.S. and world energy supply and demand.

The DOE report, the more pessimistic of the two regarding oil production prospects, projects U.S. crude oil production to be **6.9 mmbd in 1990 and 5.2 mmbd in 1995 (compared to about 9 mmbd in 1985)** if oil prices* rise from about $14/bbl in 1986 to $16/bbl by 1990 and $22/bbl by 1995. The NPC report projects slightly higher production rates at somewhat lower prices: **7.1 mmbd in 1990** and **5.7 mmbd in 1995** with oil prices at only $12/bbl in 1986 and rising to $14/bbl by 1990 and $17/bbl by 1995. Both of these projections are well within the mainstream of forecasts released within the past year, and are substantially more optimistic than several. For both, net petroleum imports reach the 50 percent level in the early 1990s.

Both reports also examine a higher oil price case. With prices in the low $20s by 1990 and the high $20s by 1995, DOE projects domestic crude oil production to be 7.8 mmbd in 1990 and 6.6 mmbd in 1995; for similar prices, NPC projects production to be 8.0 mmbd in 1990 and 7.0 in 1995. These results imply that an import fee that raised oil prices by $5 to $10/bbl could substantially slow the production decline.

DOE'S projections are based on a detailed computer model of U.S. energy supply, the Energy Information Administration's Intermediate Future Forecasting System. NPC's projections are based on a survey of U.S. and world oil supply and demand forecasts from various sources. Both projections are supplemented by quantitative and qualitative evaluations of oil supply factors. The NPC report plainly acknowledges the substantial uncertainty associated with the projections:

> Even sophisticated statistical analysis of past events is inadequate for predicting the future if the historical data do not contain an event similar to the current or expected future events . . . Energy forecasters have no recent historical events to measure the impact of sharply falling prices of petroleum . . .

Both reports identify the deterioration of industry infrastructure-loss of skilled workers, declining manufacturing capacity of critical oilfield equipment, deterioration of the rig fleet, and so forth-as a critical roadblock to a future drilling recovery. OTA shares these concerns but is somewhat more optimistic about the ability of the industry to increase its rate of additions to oil reserves if incentives improve.

Although both reports evaluate several policy options to increase domestic oil production, only the DOE report presents a quantitative analysis of these options, calculating the net costs and production response for many of them. The uncertainty associated with these estimates is likely to be extremely high, however (in some cases, e.g. lower minimum bids on Outer Continental Shelf acreage, so high that cost/production estimates were not made).

*Measured as the cost of crude oil to U.S. refiners.

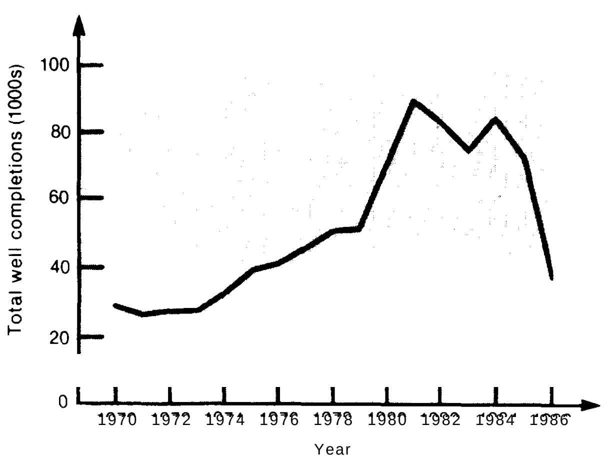
oil and petroleum products up by about 14 percent over a year before, from 4.9 mmbd, or 30 percent of total U.S. petroleum supply, to 5.6 mmbd, or 34 percent of supply.

These trends appear to be pushing U.S. oil supply towards a dependence on imports reminiscent of the situation in the late 1970s, before the production stimulating and demand suppressing effects of the two oil price shocks finally took hold and began weaning the United States from a growing reliance on foreign oil supplies. In fact, a renewed dependence on foreign supplies is precisely what the oil industry and most energy analysts are predicting for the United States—absent either a rapid return to previous price levels or major Federal intervention in the marketplace. Typically, they are projecting a likely decrease (from 1985 production levels) in domestic oil production of 2 to 3 mmbd by 1990, and similar increases in demand, if world oil prices stay at about $15/bbl. Table 1 presents several projections of future U.S. crude oil production assuming continued low oil prices, as well as projections completed before the price drop for comparison.

How and Why Would U.S. Oil Production Decline?

Several mechanisms will drive the expected production decline.

Figure 2.—Oil and Gas Drilling Trends



SOURCE Off Ice of Technology Assessment 1987: based on American Petroleum Institute data

First, production from stripper wells[2] and other marginal wells (wells with high per barrel production costs) will drop because many of these wells cannot be operated profitably at low oil prices and will be shut down. These wells cannot remain out of production for long periods; after a year (or other period depending on State rules) they have to be "plugged" (sealed with concrete) for safety and environmental reasons, and are unlikely to be reopened thereafter. Other shut down wells may be lost because of water encroachment.

Second, fewer new development wells will be drilled, yielding less new production to offset the natural decline in production from older wells,

Third, fewer exploratory wells will be drilled, yielding fewer new fields and thus fewer new opportunities for development drilling,

Fourth, production from enhanced oil recovery (EOR) operations, which seek to capture as much as possible of the estimated two-thirds of original oil-in-place left behind by conventional drilling and waterflooding, will decline because most new projects, and many planned project expansions, will be cancel led as no longer economical.

Fifth, research and development (R&D) will decline, exacerbating the overall problem because R&D traditionally has been an important driver in pushing the industry into new areas and sources of oil production as older sources decline.

In addition, many analysts warn that the industry is losing its ability to recover swiftly in the event of a return to high prices; the infrastructure necessary for such a recovery is rapidly being dismantled as drilling rigs are scrapped, cannibalized for parts, or even sold abroad; manufacturing facilities are retooled; and skilled personnel are laid off, many leaving the industry for good.

Although the reasons given for their predictions may differ, the analysts have tended to focus their arguments on three areas in particular:

[2]Wells producing 10 barrels of oil or less per day, averaged over the lease. Nearly three out of four U.S. oil wells are strippers, and these produce an average of about three bbl/day.

Table 1 .—Recent Projections of Future U.S. Oil Production

Source	Projected crude oil production (million barrels per day) 1990	1995	2000	Price expectation (dollars/bbl, 1986 dollars)
At low *prices:*				
DRI	7.8	6.3	5.5	$20 by 1995, $30 by 2000
Chevron	5.9-6.9	NA	NA	$10 to $15 thru 1987, $18 to $22 by 2000
API	6.2	NA	NA	Constant $15
CWW	6.1	NA	NA	$15
Unocal	6-6.5	NA	NA	$13.50
Amoco	6.7	NA	4.5	"Low price"
Fisher	6.8	NA	NA	$15
Conoco A	7.0	5.5	3.5	<$12 thru 1995, $20 in 2000
Conoco B	7.8	6.9	6.1	<$20 thru early 1990s, $20 in 1995, $26 in 2000
GRI D	7.3	5.4	5.0	$12 in 1986, $14 in 1990, $21 in 2000
NPC	7.1	5.7	4.5	$12 in 1986, $14 in 1990, $21 in 2000
DOE	6.9	5.2	NA	$14 to $16 thru 1990, $21 in 1995
Price outlooks of 1985:				
Chase	8.3	7.0	5.7	Drops to low $20's by 1990, rises 0.9 '\. /year thereafter
DRI B	8.6	NA	6.8	Drops to $21 by 1987, constant to 1994, $32 by 2000
EIA	8.1	6.5	NA	Dips but is $28 by 1990, $31 by 1995
GRI	8.5	8.2	7.8	Dips but is $34 by 1995, >$40 by 2000

[a]Excludes Natural Gas Liquids 1985 Product Ion, 9mmbd

NA = Not available

SOURCES: DRI Data Resources, Inc , *Energy Review*, Summer 1986.
Chevron Economics Department, Chevron Corporation, *World Energy Outlook*, June 1986
API American Petroleum Institute, Two *Energy Futures: National Choices Today for the 1990s*, July 1986 (1990 production actually for 1991)
CWW Jack L Copeland, Copeland, Wickersham, Wiley & Co , Inc , Presentation to the Keystone Energy Futures Project: Liquid Fuels Policy, July 14, 1986.
Unocal Fred L Hartley, Unocal Corp . "The High Cost of Low-Priced Oil," submitted to the U.S Senate Energy and Natural Resources Committee, March 20, 1986
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Conoco A and Conoco B Coordinating and Planning Department, Conoco, Inc , *World Energy Outlook Through 2000*, September 1986
GRI Gas Research Institute, submission to the National Petroleum Council's Survey of U.S. Future Oil and Gas Outlooks.
NPC National Petroleum Council, *Factors Affecting U.S. Oil and* Gas Outlook, February 1987.
DOE U S Department of Energy Energy *Security" A Report to the* President *of the United States*, DOE/S-0057, March 1987.
Chase Chase-Manhattan Bank, Global Petroleum Division, *World Oil and Gas* 1985, August, 1985.
DRI Data Resources Inc Energy *Review* Winter 1985.
EIA Energy Information Administration, *Annual* Energy Outlook 1985, DOE/EIA-0383(85), February 1986
GRI Gas Research Institute, *Baseline Project/on Data Book 1985 GRI Baseline Projection of US. Energy Supply and Demand* to *2010*

***Argument One:* The established models of U.S. drilling activity and oil production virtually unanimously predict low rates of drilling and rapid declines in reserve additions and production if low prices continue. Current industry surveys of expected future drilling levels, reserve additions, and production basically support these predictions.**

Available models of U.S. oil supply generally rely on extrapolation from past trends to project future levels of drilling activity, reserve replacement, and production. Under stable conditions, these models can be reliable predictive tools. They are not likely to be as reliable, however, when forced outside the range where past trends provide a good analog.

It is virtually certain that the extrapolative models of oil production are directionally correct in their prediction of a U.S. oil production decline. Under current conditions, however, policymakers should be skeptical of the accuracy of these models. The events of the past year, and of the 1980s in general, in several ways are major departures from past events. The nation has just undergone a period during which oil prices, a key determinant of industry exploration and development activity, have undergone severe dislocation, and in a direction opposite past dislocations. Moreover, during the 1980s, several companies comprising a large segment of the industry's reserve replacement capability underwent significant changes in business strategies, were restructured, or merged with other companies. In addition, the period of the early 1970s to the present has been a period of hyperinflation followed by collapse in industry **costs; the** future path of such costs–a key determinant of the economic attractiveness of new E&D investment—is unlikely to be stable or predictable.

While the results of industry surveys of future drilling rates, reserve additions, and production are very important, policy makers are likely to demand substantial analytical evidence to back up the survey results. For one thing, in recent years the industry (along with just about everybody else) has not been very successful in predicting which way prices and production would turn, and different segments of the industry and different companies often have been at odds about major resource and production projections. Second, the industry participants in these surveys have been the direct recipients of significant financial blows and have seen their friends and colleagues laid off, retired, or even bankrupted. It seems fair to have concerns about whether their expressed views of the future of the U.S. oil industry reflect a cool-headed appraisal or instead reflect their depression about the immediate results of the industry downturn. Third, the industry has a very large financial stake in any policy measures that could alleviate a production decline. Whether or not this stake affects their announced projections of future production, some policy makers and segments of the public believe that it may. These concerns suggest that an analytical verification of industry estimates, capable of being reviewed by independent analysts, would be desirable and probably necessary for public acceptance.

Argument Two: The large drop in oil prices has drastically cut oil industry revenues and placed many of the industry's past investments in jeopardy. After paying off its obligations, the industry's remaining internal cash flow is sharply reduced from earlier levels. At the same time, the industry's traditional sources of outside investment and loan capital, faced with low prices and uncertainty, have backed away from the oil market. These capital sources are particularly important to the independent sector of the industry. Without new sources of investment capital and without a restoration of cash flow from prior investments, the industry will not have enough capital to invest in the major new exploration and development ventures needed to arrest the rapid decline in production.

This argument is most important for projecting oilfield activity levels in the short term, perhaps over a **2-** or 3-year period. Many of the financial entities generally responsible for U.S. drilling and other production activities *have* been hurt badly from the large cut in revenues from their past investments; uncertainty about their survival—especially for many of the small independents—will keep away outside capital, and they have minimal internal resources. Similarly, many banks and other sources of investment capital experienced severe losses and may be reluctant to reenter the oil market. In the short term, new investment will suffer because it will take time for the industry to resolve mismatches between financial resources, drilling capability, and land positions and reserve ownership. After an industry shakeout, however, drilling and other activity, and reserve replacement, could revive *if* adequate incentives, measured by the expected profitability of new E&D investment relative to competing investments, were available. Also, a number of companies, especially those larger integrated companies and independents that had avoided large debt loads, still have substantial internal resources and/or access to external capital sources. The argument that inadequate capital resources will prevent the industry from investing in new production, which attempts to tie the level of new investments to the success of old ones, may explain short term investment behavior of the oil industry (or, at least, some segments of it) but does not adequately explain the industry's *long-term* investment behavior.

Argument Three: **The large drop in oil prices coupled with fears about future price collapses have undermined the expected profitability of new investments in exploration and development. With current price expectations and conservative investment requirements (to account for higher uncertainty), there are too few economically attractive drilling opportunities to spur continuation of the industry's past level of domestic exploration and development activity.**

This argument ties the level of future investments in reserve replacement and production directly to the economic attractiveness of these investments. In OTA's view, the attractiveness, or expected profitability, of future drilling and other production-oriented ventures is the key indicator of long-term prospects for adequate U.S. reserve replacement and production.

Current industry analyses supporting conclusions about declining U.S. oil production prospects generally stress arguments one and two and pay somewhat less attention to argument three. Models and surveys, the bases of argument one, have been widely used. The second argument about inadequate capital and reduced cash flows is analytically very straightforward and has been advanced with intensity, especially by spokespersons for the independent sector of the industry. In contrast, few in the industry have supported the third, "expected profitability" argument with the careful analysis necessary to establish its credibility.[3] The substantiation of industry projections of declining production that would be provided by a careful analysis of expected profitability must be viewed as very important in light of the high social costs—many billions of dollars—associated with many of the policy measures being considered to arrest the projected decline.

Evaluating the attractiveness of new E&D investment opportunities relative to competing investments is a complex undertaking. It would require a substantial commitment of resources and information from the industry, and much information that would be useful in such an evaluation is proprietary. Although many and perhaps most of the larger oil companies have undertaken extensive analyses of their own investment prospects, these analyses are not likely to be made available to the public. Furthermore, a credible *national* analysis will still have to rely on some form of detailed assumption about that portion of the total remaining oil resource base that is physically available to the industry for exploitation within the time frame of interest. No widely accepted resource model currently exists, although there are a few computer models of oil supply (e.g., the Gas Research Institute's Hydrocarbon Model) that constitute some first attempts at such a model.

[3] We do not doubt that many of the industry's survey responses about future 011 production levels are based on companies' private evaluations of expected profitability of new E&D investments.

An Approach to Understanding Oil Production

Given the concerns about the reliability of current oil supply models under today's radically changed economic conditions, an appropriate means to gauge future oil production is to gain an understanding of both the changes the oil industry has undergone and the forces that will drive future production. The following discussion examines:

- Economic and resource factors affecting production:
  - —changes in the economics of drilling prospects over time;
  - —changes in capital availability and how these changes affect E&D investment levels;
  - –loss of oil production from stripper wells;
  - —the nature of the oil resource base, and in particular, the availability of drilling opportunities that might remain profitable in a low price environment; and
  - —the effects on drilling of the current surplus in natural gas supply.
- Changes in the oil industry affecting production:
  - —the potential effects of industry restructuring on industry investment strategy and capabilities,
  - —the changing business climate for E&D investment overseas and its effect on domestic versus overseas spending,
  - —changes in the efficiency of exploration and development activity and their effects on rates of reserve additions and production,
  - —the potential for technological change to offset some of the drop in profitability caused by low oil prices, and
  - —the effects of a deteriorating industry infrastructure on industry's ability to rebound to higher drilling levels.

The goal of examining these factors is to *determine* whether the preponderance of evidence tends to support or undermine the industry's pessimistic predictions for future oil production, and to better understand how Congress might best intervene to shore up production *if it chose to do* SO.

Economic and Resource Factors Affecting Production

Changes in the Economics of Drilling Prospects

OTA's interviews with oil industry planners paint a pessimistic picture of remaining domestic exploration and development prospects at low prices. **Essentially all of those interviewed contend that the "inventory" of economic oil and gas prospects has shrunk enormously at mid-1986 prices of$12 to $15/bbl despite the accompanying sharp declines in drilling and other costs.** They assert that the only arena capable of supporting substantial drilling levels at these prices is relatively low-risk, low-to-moderate cost development drilling, primarily for oil objectives, with short lead times; they also assert that exploration drilling is virtually dead at these prices.

In addition to low risk shallow extension and infield drilling,[4] other prospects still considered to be viable at oil pricesof$12 to $15/bbl include:

- continuation of projects where most front-end capital has been spent (enhanced oil recovery, offshore development drilling, waterfloods[5]);
- drilling to satisfy lease and contract requirements; and
- some exploration drilling where production could not begin for 7 to 8 years or longer, so the current price environment is not relevant (although several major companies have backed away from this type of drilling).

Most of those interviewed were pessimistic that an increase to $18 to $20/bbl would spark a major drilling revival, although all felt that certain additional prospects would become economic, including:

- some deepwater Gulf of Mexico exploratory prospects;
- some onshore wildcat prospects;
- additional enhanced oil recovery, especially CO_2 gas injection projects with readily available sources of CO_2, and some projects using the injection of polymers;
- Beaufort Sea exploration and delineation drilling;
- limited offshore California development; and
- many waterflood projects.

There are only scattered published economic analyses that can offer confirmation of these assertions. In an attempt to test at least a few of the assertions, OTA examined how the expected profitability of small-scale exploration and development drilling programs i n the United States has changed over time. OTA compared 1986 profit expectations with expectations for the same physical prospects in: 1985, immediately before the major price drop; 1981, at the height of the drilling boom; and 1972–before the first OPEC price shock. Although only a few physical prospects were examined, we believe that the results are fairly widely applicable to drilling projects of modest scale.

In our analysis, we found that **the profit expectations for the 1986 drilling projects, assuming oil prices would remain in the $14/bbl range during the 1980s, were substantially lower than expectations in 1981 and 1985 in every case;** for example, onshore development well drilling projects with expected real rates of return (before taxes) of 15 percent in 1986 would have been expected to earn 35 to 52 percent in 1985 and 23 to 43 percent in 1981. Although drilling costs dropped substantially from 1981 to 1985 and, to a lesser extent, from 1985 to 1986, the oil price drop has proved to be the more important factor influencing profitability. **This result agrees strongly with the assertions of the industry that**

[4] Extension drilling seeks oil and gas just outside the known boundaries of discovered fields; infield drilling seeks oil and gas inside of these boundaries by drilling in previously undrilled sections or drilling at smaller spacing than previous drilling.

[5] Waterflooding is an oil recovery technique whereby water is injected into the reservoir to maintain or restore reservoir pressure and push additional oil towards the producing wells.

[6] *Expected profitability* is calculated by using oil price forecasts typical of the analysis year. *Realized* or *actual profitability* is calculated by using actual price levels up to the present, and forecasted or assumed price levels thereafter.

the price drop has substantially reduced the number of profitable domestic E&D opportunities.

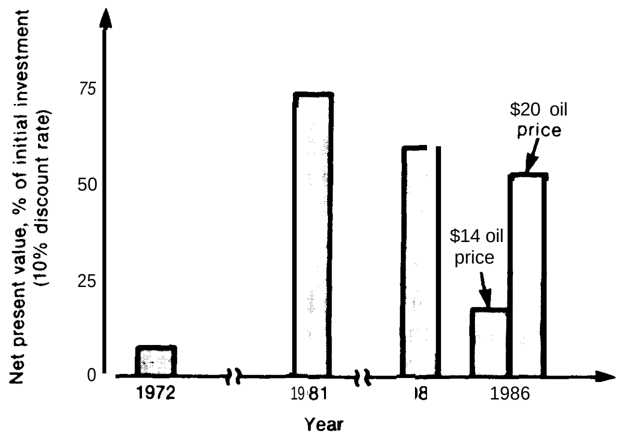
We also found, in every case, that 1986 expected profitability **(based on the assumed $14/bbl future oil price) was much better than expectations in 1972,** primarily because 1972 oil price expectations were modest. Thus, for the cases examined, today's economic conditions for drilling development wells and exploration wells aimed at small fields would appear to be substantially superior to conditions in 1972, for wells of the same physical promise. At first glance, this appears to indicate that the industry has better economic opportunities today than in 1972. Because so many of the better prospects were drilled in the years between 1972 and 1986, however, today's remaining physical prospects may be considerably poorer than those available in 1972. On the other hand, this effect of "resource depletion" is tempered by the addition of new prospects to the resource "inventory" because of improvements in exploration technologies and in geologic understanding. The net effect of these factors is unclear without further analysis, although an industry consensus would likely be that today's physical drilling prospects are substantially inferior to those available in 1972.

Figure 3 illustrates the change over time in expected profitability for a single exploration prospect in the Permian Basin, Texas.

Another important result of OTA's analysis was that the actual profit performance of the drilling projects was considerably different than the expected performance. **For the wells drilled in** *1972,* **actual profits were much higher than initially expected; for the 1981 and 1985 wells, actual profits were much lower than expected.**[7] In fact, there is little difference in realized rates of return between the 1986 wells and the 1981 and 1985 wells. The higher drilling costs incurred in 1981 and, to a lesser extent, in 1985 offset the higher average oil revenues obtained with these wells.

[7]Assuming continued $14/bbl oil prices beyond 1986

Figure 3.—How Profit Expectations for the Same Prospect Would Have Changed Over Time: An Oil Exploration Prospect in Texas' Permian Basin



The expected drilling program:
- 20 wells drilled
- 10 producing wells at 8900 ft.
- Initial year production = 222,000 bbl.
- 10 percent depletion rate

SOURCE: Office of Technology Assessment. 1987, based on Congressional Research Service analysis for this study

OTA also examined the effects of assumed $10/bbl and $20/bbl oil prices on 1986 expected profitability. **At** $20/bbl, if drilling costs do not rise, expected profitability for the projects evaluated will be in the same range as 1981 and 1985 profit expectations, implying that a drilling revival **could occur at this price level. However, the strength of any revival would be limited by increases in drilling costs that would occur as the current "surplus" of drilling services is used up. Also, for a revival to occur, producers must be reasonably assured of continued price stability.** Today, many producers say that they are requiring proposed drilling projects to pass a "low-price hurdle," that is, they must retain profitability at prices that could occur if surplus production drove prices back down again. A hurdle of $10/bbl is frequently mentioned. **At** $l0/bbl, drilling prospects that would yield 15 percent real rates of return at **$14/bbl become either outright losses or yield barely a few percent. Thus, conservative price/cost accounting in approving proposed drilling projects may be playing an important role in stifling drilling activity.**

Our analyses apply only to oil exploration and development aimed at small fields and modestsized development wells, and only to physical examples that do not stray far from average conditions. In our view, **the great importance to national policy makers of having an accurate estimate of domestic E&D economics demands a wealth of additional analysis.** This analysis must examine the full range of E&D activity, from the various forms of enhanced oil recovery to exploratory drilling in the Arctic and deep offshore, to extension well and infill drilling in older fields, and so forth. Considerable analysis is already available, for example the National Petroleum Council's report on enhanced oil recovery, but the separate analyses must be collected, intensively reviewed for accuracy, and reworked to fit into a consistent economic framework. Substantial new analyses will be needed to fill in the gaps.

Problems of Capital Availability

As noted previously, the large reductions in cash flow to the oil industry and, to a lesser extent, the withdrawal of outside loan and investment capital are widely viewed as critical factors in driving down levels of investment in oil exploration and development. Total oil and gas wellhead revenues were about $70 billion in 1986, about 43 percent below 1985 levels. Although reliable data for private financing, a major source of funds for independent producers, are not available, many industry analysts are convinced that availability of private funds has declined substantially because of current conditions in the industry. Furthermore, many of the regional banks which had financed the efforts of many small operators during the late 1970s and early 1980s were placed under severe pressure by the bankruptcies of many of their oil service industry borrowers and the reduced values of the oil and gas reserves used as collateral for their loans to independent producers. Poor performance in the agriculture and real estate sectors also played a major detrimental role in the banks' loan portfolios. Many of these banks have pulled back from the oil and gas loan market.

Although capital availability problems are widespread, they are not uniform in their intensity across the industry. The small independent producers have the worst capital problems, with no alternative sources of cash flow and profits and greatly reduced access to the external capital sources they had relied on; the larger integrated companies have been buffered somewhat against the effects of reduced production revenues by increased profits from their downstream (e.g., refining) operations. Those larger integrated companies and independents that previously had avoided large debt loads generally cannot (and do not) claim that their E&D spending is capital limited; they retain substantial internal resources and/or access to outside capital. Although most of these companies have reduced their E&D budgets and activity levels, they presumably have done so because of changed investment priorities.

Although the importance of the drop in cash flow and withdrawal of outside capital to the short-term investment behavior of the industry is not in question, this is not the case with the importance of these factors to the industry's *long-term* behavior. There is disagreement among analysts of the industry as to whether the cash flow from previous investments or the profit prospects for new investments will control the industry's future level of investment. In the past, industry investment levels appeared to be closely tied to levels of cash flow. However, classical economic theory predicts that the volume of new investment should be more closely tied to the characteristics of the new investments. Past industry financial losses and recently reported shifts in the industry's attitude about replacing company reserves—discussed in the section on industry restructuring—reinforce the view that the industry is likely to base its future decisions about the magnitude of E&D investment primarily on a careful evaluation of prospective profits.

Over a period of a few years, companies in a weakened financial condition may go out of business; undeveloped and partially developed properties and equipment will be sold at low prices; companies will merge and be restructured; problem loans will be renegotiated or written off; and new financial entities will enter the industry if good investment opportunities are available. In this manner, the industry would be in position to attract new E&D investment capital if costs are low enough and E&D efficiency high enough to create attractive E&D investment opportunities.

Losses in Oil Production From "Stripper" Wells

There is widespread concern that low oil prices will force many of the nation's "stripper" oil wells, wells whose production averages 10 barrels of oil per day or less (averaged over the lease), to shut down. Once these wells shut down for a year (or other period determined by State rules), they must be "plugged," i.e. sealed with concrete; most will never be returned to production, and their reserves will be lost. This concern is magnified by the importance of stripper wells to U.S. supply. Over *400,000* stripper wells produced approximately 1.3 mmbd, 14 percent of total domestic oil production, in 1985. These wells are concentrated in Texas, Oklahoma, California, and Kansas, which together have three-fourths of the Nation's stripper production.

The probable loss of stripper production at different price levels is highly uncertain because of a scarcity of data about stripper well physical characteristics and production costs. Furthermore, the data that are available reflect historic business practices and costs. Both stripper well operators and the businesses that serve them have been forced to make adjustments in response to the sharp drop in oil prices. Analyses of stripper well production must account for recent declines in the cost of utilities, materials, and services to operators as well as changes in operating practices, such as deferring maintenance, that affect both costs and production levels.

Two quantitative studies of lost stripper well production have been conducted. A study sponsored by the Interstate Oil Compact Commission (IOCC) estimates that, during the first year, 176,000 bbl/day of stripper production, 2 percent of total U.S. crude oil production,[8] would be lost at $18/bbl oil prices, and 277,000 bbl/day or 3.1 percent of U.S. production would be lost at $15/bbl. The Energy Information Administration (EIA) estimates a first-year loss of 85,000 bbl/day, 1 percent of U.S. production, at $18/bbl oil prices, with an additional 4,300 bbl/day loss in later years as major repairs for the still-operating wells become necessary; at $15/bbl, first year losses are estimated at 148,000 bbl/day, with later year losses of 77,500 bbl/day for a total loss of 226,000 bbl/day or 2.5 percent of U.S. production. EIA's estimated first year losses are about half of the IOCC's estimates.

More recently, an IOCC survey of California, Kansas, New Mexico, North Dakota, Oklahoma, Texas, and Wyoming indicates that 110,000 wells in these States, with 307,000 bbl/day of oil production, were shut in during 1986, with 12 percent of the wells permanently abandoned. These values do not break out the production lost solely because of low oil prices (each year, thousands of wells are abandoned even at high oil prices), and thus they are not strictly comparable to the projections above. However, most of the production loss is likely to be attributable to the price drop, and the survey appears to add credibility to the (higher) IOCC projections.

The Nature of the Resource Base

The nature of the remaining U.S. oil resource base will play a vital role in the response of U.S. domestic oil supply to changing oil prices. **There is, however, substantial disagreement in the oil industry about the physical nature of the remaining resources, about where future U.S. reserves will come from, and at what price.**

A central issue in this resource base disagreement is the question of whether the major source of new reserves will be the discovery of large new oilfields, particularly in the frontier areas and deep offshore, or whether it will instead be the aggregation of many thousands of modest increments of reserves gained by drilling new wells in old fields, improving recovery through enhanced oil recovery techniques, and exploring for small fields in familiar producing territories. These different views of the remaining resources in the United States lead to different preferences for policy initiatives (e.g., different degrees of importance attached to expanded leasing of new frontier areas) and to different views of the oil prices necessary for a revival of higher levels of reserve replenishment. Frontier and deep off-

[8]Based on average 1985 production of 8,9 mmbd.

shore oil resources may, in many cases, require prices in excess of $30/bbl for economic development, whereas a considerable portion of the resources available from the smaller scale efforts are viewed as available at prices between $15 and $25/bbl.

The recent history of oil reserve additions generally supports the view that the aggregation of many small reserve additions, especially from the growth of discovered fields through extension well drilling and other mechanisms, plays the weightier role in overall U.S. reserve growth. For example, about 70 percent of total U.S. reserve additions during 1979 to 1984 came from drilling in oilfields discovered before this period, and the percentage of total reserves coming from this source has increased from earlier decades. However, those who view the frontier areas as the critical source of new reserves believe that the intensive drilling of the last decade and a half has already squeezed most of the reserve growth available from our older fields, and that any remaining growth requires much higher prices than before because the easy reserve targets were exploited first. Unfortunately for the advocates of searching for giant fields, however, the record of the past decade of oil exploration has not been very promising, with successes in offshore California and the Gulf of Mexico perhaps more than balanced by grave disappointments in the Gulf of Alaska, Georges Bank, St. Georges Basin, and elsewhere. Clear signs of this disappointment are the very large reductions in recent industry and government estimates of frontier resources,

Resolving the potential roles that continued field growth and giant new fields may play in the future development of the United States' oil resources may not be possible at this time. **Whatever the "correct" view of the resource base turns out to be, however, both the search for giant fields as well as the intensive pursuit of small-scale reserve additions must be pursued if the slide in U.S. production is to stand any chance of being halted.**

The Effects of the Natural Gas Surplus

The state of markets for natural gas is important to oil production. Much exploratory drilling searches for hydrocarbons, not specifically for oil or gas. Added incentives for finding gas will stimulate this type of "nondirectional" drilling and lead to more oil resources being found and developed—and inadequate incentives will do the opposite. Also, because gas is present in nearly all oil wells, the profitability of these wells depends on having a market for the gas at a reasonable price.

Since the early 1980s, a surge in deliverability and declining demand in the electric utility and heavy industry sectors have created a surplus of natural gas deliverability. Low oil prices have added to the gas surplus by promoting gas-to-oil fuel switching. The gas surplus has, in turn, kept gas prices low and kept some producers from having an assured market for their production. Although the reduced incentive for gas drilling has tended to help keep drilling costs low, the net effect on oil drilling is almost certainly negative. **A tightening of gas markets in the next few years, as predicted by many experts, would have a positive effect on drilling in general and would likely lead to increased oil well completions and production capacity. However, uncertainties about the volume of additional gas imports that could be made available from Canada, the actual level of excess deliverability, the volume of gas that could be quickly added to the deliverable base, and future changes in demand for gas have lead to a substantial divergence of opinion about the timing of any end to the current natural gas surplus.**

Changes in the Oil Industry Affecting Production

The Effects of Industry Restructuring

During the 1980s, the oil industry underwent important changes that seem likely to affect the industry's exploration and development strategies and financial capabilities. These changes have included a series of mergers, both voluntary and "hostile," as well as internal restructuring measures such as asset redeployment, stock-enhancement through stock buy backs, spinoff of new companies, asset sales, elimination and consolidation of functions, and other measures. While many of these changes are widely viewed as destructive of the industry's willingness and capability to replace its reserves, some of the same changes are defended either as strengthening industry's reserve replacement capabilities or simply as being necessary to allow the participating companies to survive.

During earlier debate over the effects of mergers and acquisitions in the oil industry, many of the representatives of acquiring companies, their investment bankers, and their defenders strongly denied that exploration efforts would be reduced. Despite these assurances, mergers and acquisitions have been widely viewed as destructive of the industry's reserve replacement capability. Between 1979 and 1985, over $75 billion was spent on oil industry acquisitions in excess of $1 billion each, adding substantially to long term debt and presumably lowering the capital available for E&D spending. According to OTA's review of a group of companies, merged companies have spent substantially more of their available cash flow on debt repayment and less on oil and gas exploration than other companies. The merged companies typically cut combined capital spending significantly in 1984 to 1985, while other large companies in the group were more often maintaining or increasing their investments. In addition, a number of companies have added substantial debt in the process of fighting off attempted hostile mergers, or simply in preparing defenses against potential takeovers. **Despite potential long-term benefits of mergers such as improved management and improvements in the "fit" of assets and financial and management capabilities, the available evidence strongly suggests that the short-term effect of mergers and attempted mergers on the oil industry's investment in exploration and development has been negative on balance. Initial successes of some merged companies at reducing debt loads may, however, signal that this balance could change.**

A significant apparent change in industry behavior, more a cause of the restructuring than a symptom of it, is **a shift in emphasis among many integrated companies away from maintaining a secure domestic source of reserves to supply their refining and marketing operations, and away from the former high priority they gave to recycling much of their production revenues back into exploration and development.** Companies are now said to be evaluating E&D investment as a separate profit center, requiring each investment to meet stringent financial criteria. These behavioral shifts are said to be the result of both the financial losses incurred by many of these companies in their past E&D investments, and the easy availability of crude oil associated with the expanded role of the spot market. **If this widely perceived behavioral change is real and permanent, a return to previous levels of profit potential in production investments may not cause a return to previous levels of drilling and reserve replacement. This has negative implications for the likelihood of a "rebound" in production following a price increase.**

The Changing Business Climate Overseas

Industry experts consulted by OTA claim that one cause of the current low level of domestic investment in E&D is that the U.S. oil industry has decided to shift its domestic/overseas balance of E&D investments in favor of overseas investment.

In earlier years, many U.S. companies focused on domestic E&D despite the relative "maturity" of the United States' oil resources and the better geologic prospects overseas. They did this partly because of the greater stability and security available within the United States, but also because many oil-bearing countries offered relatively demanding terms for development of their oil resources.

Although problems of stability and security remain, **many countries have eased their terms for oil development. They have removed former caps on the prices paid to foreign developers, eased currency restrictions, lowered taxes and royalty rates, and otherwise improved the potential profitability of private oil and gas development.** At the same time, industry spokesmen have claimed the United States has enacted tax and regulatory changes that worsen the business climate for domestic oil and gas investment.

Evaluating the *relative* business climate for petroleum investments of the United States versus competing foreign nations is complicated, and OTA is not aware of a comprehensive attempt at such an evaluation. Nevertheless, **the attempts**

by many nations to ease investment restrictions and improve potential profitability in developing their oil resources clearly have increased the attractiveness of overseas investment vis-a-vis United States investment. In evaluating the effects of this increase, however, policy makers should keep in mind that most analysts believe that **any increased oil supply outside of the Middle East will tend to enhance market competitiveness and stability whether it occurs inside or outside of the United States—and that, dol**lar for dollar, overseas exploration investments will tend to purchase considerably more oil reserves than will U.S. investments.

Changes in the Efficiency of Exploration and Development Activity

An accurate projection of the reserves found and production capability created by the sharply reduced levels of drilling and other oilfield activity caused by low oil prices requires an accurate estimate of the "efficiency" of this activity, as measured by the footage and wells drilled per rig, the reserves found per well, the wildcat success rate, and so forth. These measures have proved to be sensitive to oil prices and oilfield activity levels. For example, rig efficiency (footage and wells drilled per rig per year), reserves added per well or per foot drilled, and many other measures of efficiency declined from the middle 1970s to the early 1980s as oil prices rose and oilfield activity accelerated. Part of this decline was due to the *use* of inexperienced personnel and marginal equipment, made possible by the inability of the supply of services to keep up with the demand. Another element of decline was the spread of drilling activity to more marginal prospects with lower reserves and sometimes under more difficult physical conditions. This was partly a result of the improved economics of these prospects and partly an effect of resource depletion as the best prospects were used up.

The decline in oil prices that began in 1981 forced the industry to become more efficient. For example, drilling became more efficient as the number of inexperienced drilling crews declined, inefficient rigs were dropped from service, footage and turnkey contracts replaced contracts that paid drillers by the day (day rate contracts offered little incentive for efficiency), and drilling technology improved. These factors were important causes of the sharp increase in rig efficiency measured between 1981 and 1985. The industry drilled 89,000 wells in 1981 with nearly 4,000 rotary rigs active; 84,000 wells in 1982 with 3,100 rigs active; and 85,000 in 1984 with 2,400 rigs.

Unfortunately, however, the precise dimensions of the actual increase in efficiency are obscured by other factors that also affect measured rig efficiency. These factors include:

- the proportion of total drilling devoted to exploration, because exploratory drilling is more time-consuming than development drilling;
- possible changes in the number of rigs that are not included in the datag[9]; and
- shifts in the geographic distribution of drilling, because drilling in some areas, such as the Gulf Coast, is more rapid than in others, e.g., the Midcontinent and Rocky Mountain Overthrust Belt, because of different rock conditions and other physical factors.

Similarly, **as the industry cuts budgets and drilling rates and retreats from marginal areas with high costs and low payoffs, measures such as reserves added per well or per dollar invested should improve. Consequently, reserve additions should not drop quite as precipitously as drilling or drilling budgets have. This effect will be tempered, however, by a likely shift in drilling patterns away from deep, high risk exploratory drilling (see the earlier discussion on the Economics of Drilling Prospects), and** also toward shallower and lower risk (but potentially lower yielding) targets. Also, drilling patterns are affected by company lease positions and contractual obligations.

Figure 4 shows the regional variation in oil reserves added per well, illustrating the potential effect of shifting the geographic distribution of drilling.

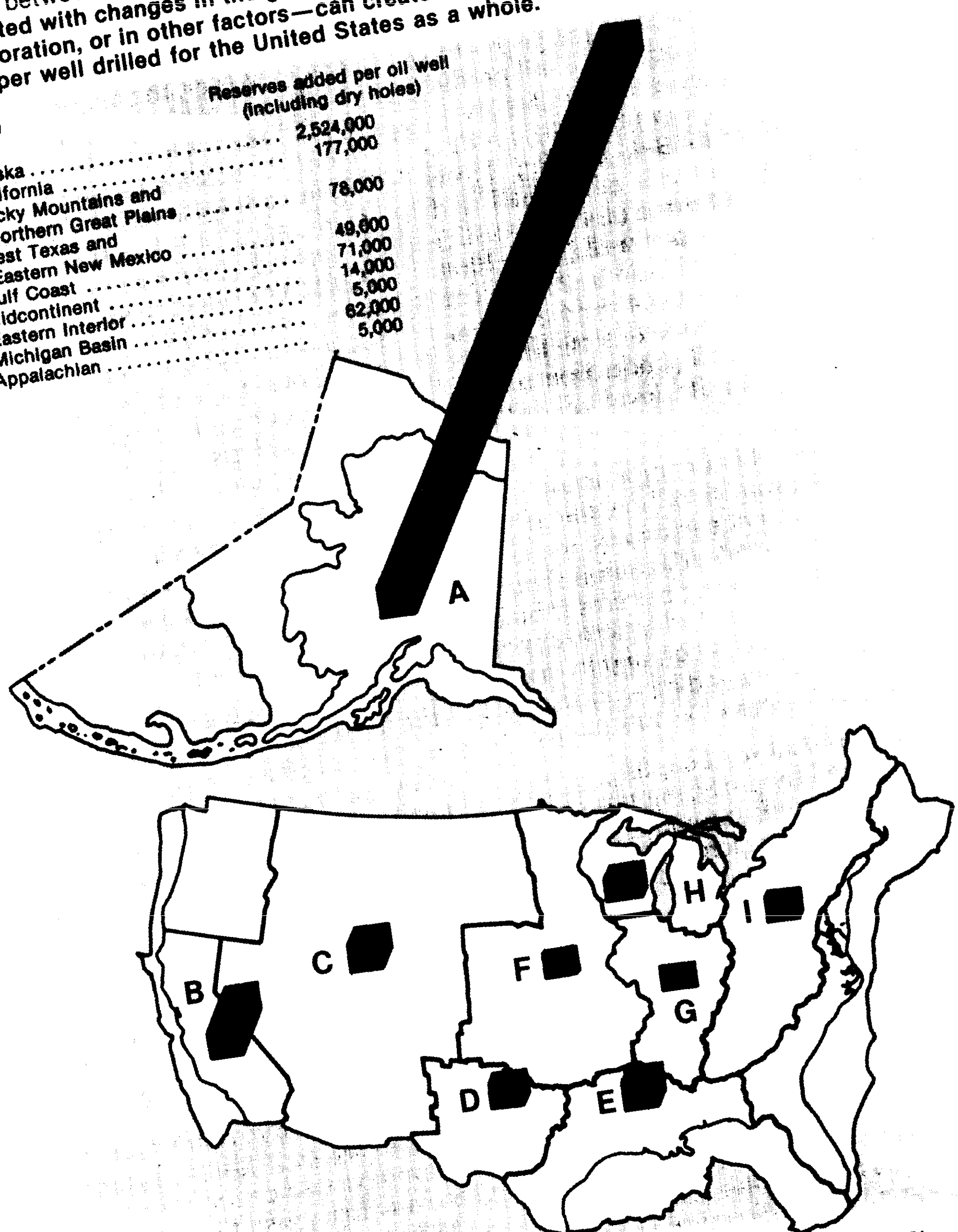
Shifts in drilling during the early part of 1986 seemed to follow the expected pattern of retreating from regions with low average returns. If only

'Commonly used rig counts include only so-called rotary drilling rigs, rigs that drill by rotating a drill bit and its attached drilling pipe.

Figure 4.—Regional Differences in Oil Reserves Added Per Well Drilled

The physical reward of drilling, measured in reserves added/well, varies considerably from region to region. Aside from these regional differences, other important factors affecting reserves/well values include the relative markets for oil and gas and the split between development and explanatory drilling. **Shifts in drilling patterns—associated with changes in the geographic distribution of drilling in the emphasis on exploration, or in other factors—can create marked changes in the oil reserves added per well drilled for the United States as a whole.**

Region	Reserves added per oil well (including dry holes)
A Alaska	2,524,000
B California	177,000
C Rocky Mountains and Northern Great Plains	78,000
D West Texas and Eastern New Mexico	49,000
E Gulf Coast	71,000
F Midcontinent	14,000
G Eastern Interior	5,000
H Michigan Basin	62,000
I Appalachian	5,000



SOURCE: Office of Technology Assessment, 1987; based on Congressional Research Service analysis for OTA.

the regional shifts in drilling are considered, the reserves added per average U.S. well in 1986 could be 37 percent higher than the 1981 to 1984 United States average.[10]

Although this estimate could be interpreted as optimistic for U.S. oil supply, in fact it is sobering. Even if these reserve/well values are correct —and they are almost certainly too high—they still imply a substantial drop in U.S. oil production if recent drilling levels continue. For example, estimating Alaskan and stripper well production separately, **if mid-1986 drilling levels continue for the next decade and a half and achieve the regionally adjusted (and optimistic) values of reserves added per well, year 2000 United States production will still be 29 percent below 1985 levels, or about 6.4 mmbd. Thus, the United States cannot hope to slow the current decline in domestic oil production unless it increases substantially its level of drilling activity.**

A reliable projection of future production rates requires an accurate estimate of how the industry will adapt its investment behavior to the new price environment. Since this adaptation should take a few years, current drilling patterns should not be viewed as permanent. At this time, a projection of likely adaptive behavior, and its likely effect on reserves/well values and other measures of E&D efficiency, will clearly be speculative.

Insight on the potential for adapting to low prices might be gained by analyzing the differences among individual oil companies' historical investment patterns, management styles, and investment outcomes. Some companies, such as Shell Oil, have had consistently low finding costs over the past decade or more. If the more successful companies have simply occupied low cost "niches" in domestic E&D, their success may not offer much room for hope that the rest of the industry could, with appropriate changes in investment behavior, successfully match their cost performance. On the other hand, if their success is owed primarily to behavior that could be copied by the rest of the industry, the long-range outlook for production might look considerably better.

10 1986 drilling based on July 1986 projections.

The Effects of Technological Change

The continuing evolution of oilfield technology, particularly as it may facilitate the exploitation of existing resources at lower cost, clearly is an important factor in the ability of the industry to keep reserve replacement and production close to historic levels in the face of low oil prices. In general, however, **the majority of the operators and analysts we talked with were skeptical of the potential for both new technology and improvements in existing technology to allow access to significant volumes of oil that currently are uneconomical at prices below $20/bbl. In support of this view, statistics of important measures of exploration and development efficiency-such as reserves added** per well drilled and exploration success rates—have either held steady or deteriorated over the past decade despite the introduction of such technologies as three dimensional seismic analysis, seismic interpretation with personal computers, advanced reservoir modeling, and an array of others. **If technology development has made a difference during the past decade, especially in the onshore lower 48 States, it appears to have been primarily one of counterbalancing the negative effects of continuing resource depletion.**

Nevertheless, **there is a significant minority in the industry who have a far more positive view of the potential of improved oilfield technology.** They can point to a number of new technologies just being deployed, or on the immediate horizon, that have promise for lowering industry costs enough to either allow development of additional resources at current low prices, or at least to allow added resource recovery at prices significantly lower than previously thought possible, often in the lower $20/bbl range. These technologies include:

- important improvements in the resolution capability and cost of seismic imagery;
- new developments in chemical enhanced recovery that lower the price threshold from $25 to $30/bbl to about $20/bbl; and
- improvements in horizontal drilling that offer the potential of expanding a field's recoverable reserves by allowing operators to exploit thinner pay zones.

Even if industry optimists are correct, the potential of new technology will not be realized without a significant R&D effort on the part of the industry. Although precise figures are not available, industry observers agree that industry R&D expenditures are down by at least ***30*** or ***40*** percent over the past 3 years. Although some cutbacks clearly are appropriate (e.g., for efforts aimed at accessing very high-cost resources in difficult environments that are not now technically recoverable) the overall size of the cutbacks and a general shift away from long term research targets are of substantial concern.

Effects of a Deteriorating Industry Infrastructure

The large drop in industry activity levels accompanying the price drop has meant a shrinking of the industry's "in frastructure," that is, the inventory of rigs and other equipment used in exploration and development activity, the manufacturing capacity to produce the equipment, and the people to man the equipment and plan and supervise its use. The industry has expressed the concern that, in the event of an oil price rise or other incentive for a "rebound" in activity levels, the lack of infrastructure would mean severe delays, inefficiency, and cost inflation as too much demand for oilfield goods and services chases too little supply–a repeat of the hyperinflation in these goods and services that marked the middle to late 1970s and early 1980s.

Any rapid improvement in E&D investment prospects, fueling increased demand for oilfield goods and services, will create delays and inflationary pressure, but increasing effective oilfield activity should be less difficult and inflationary than it was in the 1970s. One reason for this conclusion is that the level of activity of the earlier drilling "boom" was much higher than was justified by the results, primarily because drilling rigs were operated inefficiently, inadequate equipment was used, and many wells were drilled with minimal prospects for success. Thus, **it is not necessary to return to 1981** *levels* **of active rigs or employment to achieve 1981 levels of reserve additions and added production capacity.** Another reason is that most oilfield equipment is relatively sturdy and will not deteriorate excessively if moderate precautions are taken in storage. Finally, in recent years there has been an oversupply of trained workers and professionals in the industry, and there is little reason to believe that most of these have been irrevocably lost to other fields. **A *2,500* rig fleet, operating efficiently, probably can achieve the same results as a 4,000 rig fleet did in 1981. For now and for at least another few years, there should be adequate equipment and personnel to assemble and operate such a fleet relatively quickly —perhaps within 6 months to a year. However, this conclusion presupposes that a rebound in oilfield activity levels will be accompanied by investor and industry confidence that the rebound will not be short-lived, so that contractors will be willing to invest in refurbishing rigs, laid off workers will be willing to return, etc. This is not necessarily a foregone conclusion given the "lesson" administered by the recent price drop. Also, the capability for a rebound will decline over time.**

Policy makers should recognize that OTA's guarded optimism about the ability of industry infrastructure to support a rebound in activity is not shared either by the National Petroleum Council or the Department of Energy. Their respective reports, *Factors Affecting U.S. Oil and Gas Outlook* and *Energy Security,* both identify the destruction of the industry's infrastructure as a key roadblock to a drilling recovery.

Resisting a Decline in U.S. Oil Production: Should Government Play an Active Role?

For reasons encompassing both national security and U.S. economic competitiveness, many energy analysts and significant segments of the oil industry (especially the independent producers) are arguing that the Federal Government should intervene to halt or ameliorate the expected decline in U.S. oil production.

The policy preferences of Federal policy makers are likely to depend on how they would answer the following two questions:

1. Will declining domestic oil production seriously damage U.S. economic and national security interests? and

2. Can Federal intervention succeed at stabilizing domestic crude oil production without incurring unacceptably high costs (in terms of direct consumer spending, Federal budget impacts, or market distortions)?

Properly addressing both of these questions requires a comprehensive examination of U.S. and world energy supply and demand, not merely an examination of domestic oil production. For example, the shift in oil trade away from long term contracts to the spot market has served to make the world oil market more unified. With the present market structure, new discoveries and production capabilities anywhere in the world–and especially outside of the Middle Eastern OPEC nations–contribute to market stability and thus to U.S. economic and national security interests, Similarly, the ability of energy consumers to switch to other fuels, improve their efficiency of energy use, or even shift the basic structure of their economies will affect their reliance on oil. Consequently, an evaluation of United States crude oil production can provide only a piece of a larger puzzle, albeit an important piece. In the following discussion, we address the above questions in the limited fashion allowed by the bounds of our analysis.

Will Declining Domestic Oil Production Seriously Damage U.S. Economic and National Security Interests?

If imports provide the least expensive source of oil, should we care if U.S. domestic oil production decreases and import dependence rises? Are the potential damages from rising import dependence large enough to justify the costs to the U.S. economy of subsidizing domestic oil production or taking other measures to restrain import levels? This question forms the core of a serious policy dispute. Unfortunately for policy makers, there are a number of substantive opposing arguments as well as significant uncertainties about this issue.

Advocates of oil import fees and other measures designed to forestall added U.S. dependence on oil imports believe that both economic and national security interests justify the costs of such measures. They note that the drop in oil industry investment has hurt significant sectors of the national economy as well as the economies of oil-producing States such as Texas, Oklahoma, and Louisiana, and that expanded imports hurt the U.S. trade balance. Perhaps most important from an economic standpoint, they believe that expected increases in oil demand and decreases in non-OPEC oil production capacity will soon return market control to OPEC and thus restore the potential for future price shocks and accompanying economic disruption. As for national security, the industry points to the strategic importance of oil to the United States, both for itself and even more for its allies, and the likelihood that increased import dependence will translate into an increased vulnerability to future oil disruptions.

These arguments must be balanced against the potential negative impacts an import fee or the like would have on the U.S. economy, as well as arguments that the national security implications of rising oil imports have been tempered substantially by economic and physical changes that have occurred since the earlier price shocks.

The negative economic effects of an import fee are viewed as including an increase in the rate of inflation, a decline in gross national product resulting from reduced discretionary income, and a decline in trade competitiveness among the United States' energy-intensive industries (e.g., chemical products). Balancing negative and positive impacts requires extensive, sophisticated economic analysis, with the best analyses yielding results that will still be highly sensitive to arguable input assumptions.

Changes in oil markets and the U.S. economic structure that have occurred since the early 1970s, combined with certain insurance measures such as the Strategic Petroleum Reserve, have likely made the United States less vulnerable than previously to future oil price shocks and supply disruptions. For example, the growth of a large spot market in crude oil has made embargoes extremely difficult to enforce and should act to curb the "inventory panic" that in the past served to escalate prices rapidly at the first signs of a shortage. Other positive changes include:

- the U.S. decontrol of oil prices, which allows a more rapid market adjustment to changes in oil supply and prices;

- the increase in diversification of producing countries, which adds stability to world supply;
- the increase in oil stocks held by Japan, West Germany, and other U.S. allies; and
- the growth of natural gas supplies throughout the world, which allows for substantial fuel-switching capability in industrial and electric utility markets.

Although these improvements in the U.S. strategic situation do not imply that growing oil import levels represent no threat, they do imply that comparisons with earlier years must be viewed cautiously.

To keep these arguments in perspective, it is important to understand where U.S. oil production was heading before prices dropped so precipitously. **Even before the sharp 1986 declines in world oil prices, most energy analysts were predicting a future of declining domestic oil production and increasing imports.** For example, one so-called "consensus view" of future U.S. production under previous price expectations (prices in the mid to low $20s/bbl for a few years and a gradual increase thereafter) had U.S. production declining from about 8.9 mmbd in 1985 to below 7 mmbd by 1995 and below 6 mmbd by 2000. Therefore, **the recent price drop might be said to have advanced by 5 or 10 years a process of declining U.S. production that most industry analysts believe would have occurred anyway because of the maturity, and thus declining prospects, of the U.S. resource base.**

Not all analysts would agree with this view. A minority of oil analysts believe that U.S. production could have been maintained at stable levels for another few decades had oil prices held up and had the industry expanded its efforts to attain increased recovery from its older fields. This more positive view is based on an optimistic assessment of the remaining oil resources that can be recovered by more intensive drilling as well as by enhanced recovery. If correct, this view implies that the "cost" of the price drop to the United States, in terms of lost domestic production capacity, could be considerably greater than implied by the more pessimistic pre-price drop production forecasts.

Policies To Bolster U.S. Oil Production

Advocates of government action to slow the decline in U.S. oil production have suggested a variety of potential solutions, Most involve substantial present or future costs; all of these are opposed by powerful constituencies.

OTA has not undertaken the kind of comprehensive evaluation that policy makers must have before deciding on a specific course of action. Although the results of OTA's study offer a number of insights about the effectiveness of specific policies, we were not able to measure the actual effects on oil production of the policies nor their net social costs.

1. **Oil Import Fees.–Oil import fees may be structured** either as a constant dollar addition to the prevailing price of imports or as a sliding fee designed to raise import prices to a predetermined value (e.g. $25/bbl). An interesting alternative is a price floor, deliberately set below prices prevailing at the time of enaction, designed to guard against future price drops and thus to ease the downside risk of new production investments.

To the extent that an import fee raises domestic oil prices higher than prices that would have occurred without it,[11] it will raise industry revenues and improve the prospective profitability of new production investments. This in turn will ensure that oil investment and production will also be higher than without the fee, at least for a considerable period. For example, **OTA's economic analyses show that for the small scale development and exploratory drilling prospects examined, increasing oil prices from $1s to $20/bbl raised expected rates of return to the levels expected in 1981,[12] when oilfield activity was at a peak. Such an increase in expected profitability would be bound to stimulate new oil investment.** However, policy makers must be con-

[11] Over the long term, an import fee might help to hold down world oil prices by reducing the demand for imports and thus reducing OPEC market dominance. It is therefore quite conceivable that the net domestic oil price could eventually be lower than it would have been in the absence of the fee.

[12] Assuming drilling costs would not rise. This assumption will be reasonable only if any increase in drilling activity stimulated by the price rise was not so large as to use up much of the current surplus of drilling capacity.

cerned about the cost to consumers of higher oil prices, both directly and as a result of higher manufacturing costs, and the effects of such higher costs on the U.S. balance of trade. In addition, because of uncertainties about the resource base, the effects of structural changes in the industry, and other factors affecting production, policymakers cannot predict with a high **degree of confidence how much additional production will be "purchased" with an import fee. There is little agreement in the industry as to what oil price would be necessary to stabilize production—or whether it is even possible to do so.**

Based on OTA's conversations with industry planners, the sharply perceived threat of future plunges in oil prices plays an important role in industry reluctance to invest, especially for longer term projects. If this is so, the institution of a provisional tax designed to establish a price **floor below current price levels–possibly at $15/bbl —could also boost investment at no immediate cost to consumers. OTA's** economic analyses reveal some of the potential of such a price floor. For small-scale development and exploratory drilling, **using a $10/bbl "hurdle price" to guard against future price risk transforms an attractive prospect at $15/bbl—with a projected real (before tax) rate of return of over 15 percent—into an outright loser. Thus, for investors who feared future price drops, a price floor could provide the assurance necessary to proceed with drilling.**

The perceived attractiveness of a price floor depends in large measure on the policy maker's expectations for future oil prices. If he expects prices to stay above $15/bbl at most times, with occasional brief declines below this price, a $15 price floor looks particularly attractive because it reduces risk at a low cost. On the other hand, if he envisions prices plunging below the floor price for extended periods, the consumer cost and balance of trade questions may become paramount.

2. **Tax Concessions.—OTA** examined the effects of several tax changes on the expected profitability of small-scale drilling. These changes included reinstituting investment tax credits (of 20 percent), allowing a 27.5-percent depletion allowance for all producers, cutting severance and ad valorem taxes in half and to zero, and instituting a 20-percent drilling credit. **For the small-scale drilling examined, lower State taxes and additional tax credits for Federal income taxes improved the prospective profitability of new investments, with a 20-percent drilling credit and a higher depletion allowance having the greatest effect. However, none of these measures achieved nearly as much of an increase in profitability as a $6/bbl increase in oil prices.[13] For example, for the development wells examined, cutting severance taxes in half added about 2 percentage points to the real after tax rate of return, whereas adding $6/bbl to the oil price increased the return by between 12 and 17 percentage points.**

Industry spokespersons have claimed that the new tax code will hurt the industry's investment capability. An examination of this claim is beyond the scope of this study. However, OTA did examine the effect of the new code on the profit expectations for a series of small scale exploration programs. **Contrary to OTA's expectations, the calculated after tax return on investment from a number of small exploratory drilling programs was slightly higher under the new tax code than under the old.** For these cases, the benefits of the lower tax rates in the new code outweighed the loss of the investment tax credit. Were company profits low or nonexistent, however, the lower tax rates would have little value and the loss of the investment credit would have been the primary factor. The alternative minimum tax in the new code, not accounted for here, may also affect the balance of the old and new codes.

The industry has been united in its advocacy of repeal of the Windfall Profits Tax (WPT), which was originally enacted to prevent domestic producers from obtaining a financial windfall from the decontrol of domestic oil prices. Although the tax is not collected at today's lower oil prices, it represents both an administrative burden to the industry and a disincentive to **E&D** investment, especially for projects with delayed production starts and for investors who expect oil prices to rise significantly during the production lifetime

[13]The reader is reminded that a fair comparison of alternative policy measures requires an estimate of costs as well as results. Ideally, policies should be judged based on a measure of (production gained) /(cost).

of the project. The magnitude of the investment incentive represented by WPT repeal depends on the price expectations of the oil companies; given the wide range of announced price forecasts and the current turmoil in the market, estimates of the oil production potentially added by repeal will be especially uncertain,

3. **Removing the Ban on Oil Exports From the United** States.– Federal law currently prohibits the export of Alaskan North Slope crude oil from the United States. The effect is primarily to force the shipment of Alaskan crude oil via high-cost domestic tankers to a saturated west coast market or all the way to gulf coast or east coast markets. Were Alaskan oil to be shipped via lowest cost tankers to Pacific markets, the reduced shipping costs would yield a significantly higher net back price to the producer; additionally, reduced pressure on west coast markets would likely raise producer prices there as well. **The Minerals Management Service has estimated the prospective increase in Alaskan wellhead prices resulting from an end to the export ban to be** $2 **to** *$3/* **bbl;** others have estimated the increase to be as high as $4 or $5/bbl. Even at the lower end of the range, **the price differential represents a significant percentage of current well head prices,** because these are kept well below world oil price levels by the Trans-Alaskan pipeline fee (about $6/bbl) and other shipping and tax costs.

4. **Bolstering Investment in** R&D.—Improving the technology of exploration, development, and production is an important means by which the oil industry can minimize the negative effects on oil production associated with continuing low prices. As noted earlier, however, the industry has been cutting back on R&D in line with its decreasing oil and gas revenues. In particular, the oilfield service sector has played a major role in previous industry R&D, yet has absorbed the brunt of financial damage associated with the price drop.

Research and technology development that could help the industry stem the production slide at low prices include:

- improved understanding of the potential for adding new reserves in older fields from conventional drilling;
- improvement in enhanced oil recovery technologies, and better understanding of how to apply them to a wide variety of geologic situations;
- improvement in the resolution and cost of seismic analyses, to allow the wider use of pre-drilling geologic analysis, to reduce dry hole risk, and to allow better placement for development wells; and
- further development of offshore production technologies that negate or moderate the requirement for giant production platforms.

The first three research areas might be included in a more general program aimed at improving the state-of-the-art in petroleum geosciences (i.e., improving our understanding of where the oil is in a reservoir, how it moves, and how it can be recovered).

Policies to bolster R&D appear especially attractive because they are an order-of-magnitude less expensive than direct economic incentives for increased production. However, policy makers must recognize that most industry planners believe that technological change can play only a modest role in stopping a production slide in the face of continuing low prices. Also, designing a policy measure that will provide an efficient incentive to promote *effective* R&D is not likely to be easy, with particular problems being industry fears about losing proprietary advantages, the potential for government direction to be out of touch with industry requirements, and the difficulty of restricting the benefits of incentive programs to the primary R&D objectives.

Suggested policies for bolstering R&D include:

- government sponsorship of industry/university cooperative projects,
- allowing intra-industry cooperative projects by granting anti-trust exemptions,
- direct government assistance in the form of grants and contract awards,
- government-directed research projects, and
- tax incentives.

5. Removing Leasing Restrictions on Frontier/ Offshore Areas.–Industry groups have long urged the Federal Government to open up a variety of publicly owned properties to oil exploration and development as a means of bolstering domestic oil reserves and production capacity. This recommendation has become more urgent in light of the recent oil price drop and its projected negative impact on domestic production. Two of the primary target areas are the California offshore basins and the Arctic National Wildlife Refuge (ANWR); both have potential recoverable oil resources of a few billion barrels. Both of these areas have been held from leasing because of environmental objections. For California, the primary objections involve the potential effects of spills on vulnerable ecosystems and high-value recreational areas and the air quality problems associated with production, transportation, and other ancillary facilities associated with development. For ANWR, the primary objection is the potential danger to the Porcupine Caribou herd and to other important species, and the loss of the area's wilderness character.

Arguments about opening these areas to oil exploration and development center about three types of questions:

1. Are the estimates of environmental impacts accurate?
2. Will development of the areas really make a difference in the United States' long-term strategic position vis-a-vis energy supply?
3. Which are more important, the environmental values that would be preserved by foregoing development or the energy supplies that would be made available? Is it possible to have development while protecting *most* of the environmental values.

These questions have been extensively aired in the media and in reports and congressional testimony, and there is little OTA can add at this time. One point worth making, however, is that volumes of oil obtained from these areas should be compared to rates of domestic oil production, and *not* to total U.S. energy consumption, as is sometimes done to illustrate the supposed insignificance of the resource. By the time areas such as ANWR could be developed—not much before 2000–oil will be even less interchangeable with alternative fuels than it is now, assuming the share of oil used for transportation fuel or chemical feedstocks continues to grow.

Chapter 1

Introduction

The Origins of Today's Low Oil Prices

In December 1985, the Kingdom of Saudi Arabia reversed its oil market strategy. During the first half of the 1980s it had been serving as the "balance wheel" of the world oil market, raising or cutting back its oil production rate to restrain or shore up prices as necessary, thus maintaining a precarious balance between world oil demand and production capacity. During this time, however, powerful economic forces were eroding its position. The stimulus to oil exploration and development provided by the price boosts of 1973 and 1979 had led to large increases in non-OPEC oil production. From a production rate of 25.6 million barrels per day (mmbd) in 1974, non-OPEC production rose to 37.2 mmbd in 1985.[1] Simultaneously, the higher prices were encouraging investments in energy efficiency; behavioral changes leading to reduced oil use; and fuel switching from oil to coal, natural gas, and other energy sources. Consequently, despite a worldwide rise in economic output of 15 percent between 1979 and 1985, worldwide oil consumption declined by nearly 6 mmbd,[2] or 9 percent, during the same period.

World oil prices continued for a time on an upward path despite these trends, largely due to the OPEC countries'–and particularly the Saudis'–willingness to cut their production rates to reduce the downward pressure on prices. Between 1979 and 1985, OPEC production was cut in half, and its oil revenues declined from $285 billion (1985$) in 1980 to $131 billion in 1985. The Saudis, having the largest oil reserves and production capacity in OPEC, and having a relatively small population (and thus relatively lower revenue needs), absorbed the brunt of these declines, allowing their production to drop from nearly 10 mmbd during 1979-81 to 2 mmbd during the third quarter of 1985. Finally, however, faced with expectations of still further production cuts and the unacceptable prospect of a rapid drawdown of their capital reserves, they announced their intention to recapture a fair market share, doubled their production rate, and instituted a series of contractual offerings to oil buyers that gave Saudi oil a competitive advantage in the market.

The immediate result was a sharp drop in oil prices as competing oil producers scrambled to maintain their own market shares. Within 4 months, the average price of oil had been cut in half, from approximately $28/bbl in December of 1985 to $14bbl in April of 1986. From there the price has fluctuated, dropping below $10 in July and rising to about $15 in September and $18 by the end of the year. And although there is no consensus as to how prices will behave in the short term, there is almost a universal expectation that oil prices for the next few decades will be significantly lower than the prices projected prior to the Saudi action.

Effects on the Oil Industry

The consequences of the price drop have reverberated through the world economy: the economies of principal oil exporting nations have generally suffered because of sharply reduced oil revenues, while oil importing nations are enjoying the equivalent of a large tax cut. The prices of competing energy sources have been forced downward to compete with newly cheap oil, while production costs of energy-intensive goods and services have dropped. Producers of high-cost oil—and particularly producers in the United States–now face prices that in many cases do not cover replacement costs for their oil, and in some cases do not even cover operating costs. For these producers, the price drop has brought massive economic disruption and the prospects for substantial production declines. In addition, the lower oil prices also appear likely to boost domestic oil consumption. These expected production and consumption trends will result in increased U.S. dependency on foreign oil, and

[1] Arthur Andersen & Co, and Cambridge Energy Research Associates, *World Oil Trends: A Statistical Profile*, 1986-87 ed., tables 6 and 10. Excluding natural gas liquids.

[2] Ibid,

possibly increased vulnerability to future oil cutoffs.

Although estimates of the timing and extent of the expected drop in U.S. crude oils[3] production differ, a mean value for the expected size of the drop would likely be about 2 mmbd by **1990 (from a base of 8.9 mmbd in 1985) if prices average about $15/bbl.** This reduction would be the cumulative effect of several forces. First, marginal producing wells with high production costs will be shut in either because revenues are too low to pay for daily operating costs, or because the wells require expensive "workovers" that no longer appear attractive at the low prices. Of primary concern here are the several hundred thousand "stripper wells, " wells producing 10 barrels per day (bbl/day) or less, that currently account for about 15 percent of U.S. oil production. Second, plans for many of the secondary and tertiary recovery operations that partially compensate for normal production declines in older fields will be canceled and, in a few cases where operating costs are high, existing operations will be shut down. Third, fewer development wells will be drilled; these wells also help maintain field production despite normal production declines in existing wells. Fourth, a slowdown in exploration will depress the inventory of newly discovered fields, and the development prospects associated with those fields, further depressing development well drilling in the future. And fifth, reductions in R&D expenditures will slow the development of new technologies and the acquisition of new knowledge that in the past helped the industry to increase oil recovery and find new sources of oil.

This process appears to have begun. Average U.S. crude oil production during 1986 was 3.3 percent, or 297,000 bbl/day, below 1985 production, while oil products supplied to consumers rose 2.7 percent, or 423,000 bbl/day. Net imports have risen by 24 percent or 1,007,000 bbl/day over the same period.[4] Also, on a monthly basis, production has dropped even more: from December 1985 to December 1986, U.S. crude oil production dropped by 670,000 bbl/day, or over 7 percents

Although the early 1980s was a boom period in oil drilling, *exploratory* drilling and other exploration activity peaked as early as 1981 and declined rather steadily through 1985, and total oil well completions began to slide in 1985 and dropped precipitously in 1986. Although many analysts view the earlier drops in activity as a necessary correction after a drilling boom, most view the 1986 drop as a virtual dismantling of two important segments of the domestic oil industry, the independent producers and the well service companies, that will greatly harm prospects for U.S. domestic oil production.

Among the activity declines are the following:

- *seismic crew count* dropped by four-fifths from its September 1981 peak to September 1986;
- overall *industry employment* dropped from a 1982 high of 708,000 to **422,000** in September of 1986; oilfield service company employment absorbed four-fifths of the drop, going from 435,000 to 206,000 during the same period;
- *unemployment of senior petroleum geologists* is 25 percent according to a recent American Association of Petroleum Geologists poll;
- *drilling rig counts and utilization rates* fell from 3,970 and 79 percent in 1981 to 3,105 and 55 percent in 1982, to 1,976 and 45 percent in 1985, to about 700 and 20 percent in mid-1986—rig count has since rebounded slightly;
- *we// completions,* which peaked at about 89,000 in 1981 and were still at 73,000 in 1985, slid to slightly below 40,000 in 1986;[6] and

[3]That is, crude plus natural gas liquids recovered in the field, called lease condensate. This is generally what is being referred to when the terms "crude oil" or "oil" production are used. "Total liquids" or "petroleum" production includes, in addition, natural gas liquids recovered from gas processing plants, refinery processing gain, and alcohols.

[4]Energy Information Administration, *Week/y Petroleum Status Report. Data for Weeks Ended: Dec. 26, 1986, Jan. 2, 1987,* DOE/EIA-0208(87-01)(87-02).

'Ibid.

[6]Independent Petroleum Association of America, "united States Petroleum Statistics, 1986 Final, " and "American Petroleum Institute, Quarterly Completion Report, First Quarter 1987. "

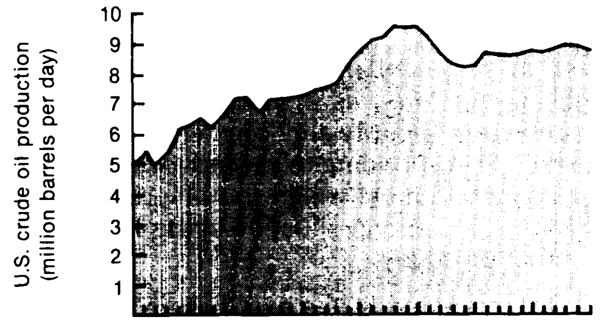
- *exploration/production capital spending* has slid from about $50 billion in both 1981 and 1982 to $33 billion in 1985 and then to $16 billion in 1986.[7]

To an extent, this drop in domestic oil production and industry activity levels is reminiscent of the production decline and drop in drilling that occurred in the early to middle 1970s. As show in figure 5, U.S. crude oil production had been climbing steadily for decades before the 1970s, and peaked at about 9.6 mmbd in 1970. Production then began a decline that lasted until 1976. in that year, however, the downward trend was arrested by a combination of a surge in drilling activity that slowed and eventually stopped the decline in production the Lower 48 States, and the onset of production from Prudhoe Bay in Alaska. Prudhoe Bay production eventually reached 1.8 mmbd, almost 20 percent of U.S. oil production, by 1985. Had the 1970-76 rate of decline continued without abatement, lower 48 production would have been 1.7 mmbd lower in 1985 than it actually was; without Alaska as well, U.S. production would have been 3.5 mmbd—more than a third–lower in 1985 (assuming that the effort expended in developing and producing Alaskan oil would not have been transferred elsewhere). Many in the oil industry point to the "rescue" of U.S. oil production by a combination of intensive drilling and the opening of new "frontier" production as a warning for the future if activity levels do not recover and new frontier areas are not opened for exploration and development.

Congressional Concerns

Congress has two basic reasons to be concerned about low oil prices. First, the reduced prices have important implications for the entire U.S. economy. Some of the implications are clearly positive, at least in the short term—the reductions in energy costs to both consumers and industry, and the expected economic stimulus provided by these reductions. Some, however, are sharply negative—the severe reductions in revenue streams and values of energy reserves held by energy producers, the resulting drop in investments in exploration and development, and the subsequent loss of business suffered by industries servicing the producers; the damage to the U.S. banking industry caused by the widespread company failures and loan defaults; the potential loss of business suffered by industries supplying products and services that are marketed primarily for their energy-conserving features; and the unemployment, loss of tax receipts, and other negative effects flowing from these problems, largely concentrated in a few key oil-producing States such as Texas, Louisiana, and Oklahoma.

Figure 5.—U.S. Crude Oil Production, 1947-86



SOURCE: American Petroleum Institute (Energy Information Administration).

Second, to the extent that the projections of reduced domestic oil production and increased oil demand are correct and the United States is forced to resume high levels of oil imports from politically insecure sources, the current lower prices may represent a potential threat to the United States' national security as well as to its future economic health. Congress clearly viewed the high levels of oil imports of the 1970s as just such a threat, and responded with extensive legislation including programs to promote synfuels development, tax incentives for energy conservation and alternative energy sources, an extensive energy R&D program, and the establishment of the Strategic Petroleum Reserve (SPR). In addition, funds were appropriated to establish military forces specifically designed to deal with threats far from established U.S. military bases, and in particular the Middle Eastern oilfields.

[7]Arthur Andersen & Co. and Cambridge Energy Research Associates, *World Oil Trends: A Statistical Profile,* 1986-87 ed.; and *Oil and Gas journal,* Feb. 23, 1987, p. 31,

Industry advocates of strong congressional measures to fight the increases in U.S. oil imports projected to result from low oil prices have portrayed these potential increases in precisely the same manner, i.e., as a serious threat to the United States' security and long-term economic interests. in responding to this advocacy, however, Congress must weigh the differences between the U.S. energy situation in the 1970s and the situation today,

First, the United States now has an SPR containing approximately 500 million barrels of crude oil, the equivalent of about 100 days of oil imports at current levels. Similarly, Europe and Japan have also added to their strategic storage, although not to the same extent as the United States.

Second, world oil production has become substantially more diversified since the 1970s, with OPEC's share of the world oil market declining from 60 percent in 1979 to approximately 35 percent today, For several years, at least, no single country or cohesive group of countries can control as large a share of the world market as was possible previously. Eventually, however, if oil prices remain below $20/bbl, OPEC may regain its previous market share.

Third, a considerable portion of any increase in oil consumption both in the United States and in the remainder of the Free World will be reversible. For example, much of increased oil use in transportation will involve changes in consumer behavior, such as increased driving, that would be quickly reversed in case of an oil shortage or large price increase. In the industrial sector, the shifts to oil for a boiler fuel can be rapidly reversed with a shift back to coal or natural gas. Similarly, in the electric utility sector, a substantial portion of any increased oil use is likely to involve the use of existing oil-fired generating capacity—removed from baseline service when oil prices rose in the 1970s—at the expense of coal, gas, or even nuclear plants. As long as the industry retains excess generating capacity, this use can be readily reversed,

A threat to reversibility is the potential for inadequate supplies of natural gas resulting from the same drilling slowdown acting to reduce oil production. This potential is a realistic possibility only in the United States. There is considerable controversy about U.S. gas supply adequacy for the future. Some analysts are projecting an imminent market tightening within just a few years if gas prices stay low, followed by supply problems as domestic production capability continues to decline. Others claim, however, that such a shortage is extremely unlikely, because additional large volumes of gas can be made available rapidly if markets tighten, by increasing import levels and by developing reserves now kept out of the market by low demand.

Fourth, the United States and its allies have undergone two major price shocks in the recent past, and this additional experience, as well as a series of international agreements on oil sharing, may assist them in a future supply crisis. Many oil experts are skeptical about the usefulness of these agreements, however.

Fifth, U.S. oil prices are no longer controlled as they were during the 1970s. In the event of a new price increase, the market forces that act to reduce demand and increase supply will be felt in full (assuming price controls are not resumed).

Sixth, most of the world's oil trade now operates on the spot market, in contrast to the long-term contracts of the 1970s. Coupled with an active futures market, this new oil trading situation makes single country embargoes, which could never be airtight even in the past, still less of a threat.

These mostly positive changes in the world oil market do not negate arguments that United States security can be threatened by an increase in oil imports, but they clearly lessen the overall risk and should be carefully considered in any policy debate.

The OTA Study

In April, 1986, the Chairmen of the Committee on Government Operations, the Committee *on* Energy and Commerce, and the Subcommittee on Fossil and Synthetic Fuels of the U.S. House of Representatives asked the Office of Technology Assessment to assess "the effect of volatile oil prices on short- and long-term domestic oil production . . . (including) an examination of changes in the industry that have already occurred . , . and an evaluation of the significance of these changes to domestic production."[8]

OTA's approach to this assessment explicitly acknowledges the high degree of uncertainty associated with attempting to project future domestic oil production. One cause of this uncertainty is that much of the data on the exploration and development opportunities available to the industry—a crucial determinant of its future behavior and thus of future production potential—is held closely by the individual oil companies. Another cause is that most of the projections available to the public are based on extrapolations from past experience . . . but there has not been a rapid decline in oil prices within the past several decades. It seems reasonable to question whether the statistical record, amassed during a period of escalating prices, is sufficient to forecast the future actions of the oil industry and the likely effects on production of these actions.

Consequently, OTA has not tried to produce yet another forecast based on extrapolation. Instead, we have examined and attempted to gain an understanding of an array of factors that will influence future production, with the dual goals of, first, determining how production outcomes may differ from those predicted by extrapolating from past experience, and second, determining how government action might influence future production rates. The factors we examined include:

- changes in industry business strategies and capabilities associated with the restructuring the industry has undergone;
- the profit potential of the array of exploration, development, and production prospects available to the industry;
- the physical nature of the oil resource base;
- changes in the climate for oil and gas investment overseas;
- the deterioration of the industry's service sector;
- the surplus of natural gas deliverability; and
- changes in exploration and development technology.

While OTA could not comprehensively analyze each of these factors and reliably determine their exact effects on future production, it is hoped hope that this study will contribute significantly to Congress' understanding of—and ability to respond to—the evolving domestic oil supply situation.

[8]Letter of Apr. 17, 1986, Jack Brooks, Chairman, Committee on Government Operations, U.S. House of Representatives, to Dr. John H. Gibbons, Director, Office of Technology Assessment.

Chapter 2

Projections of U.S. Crude Oil Production

Introduction

projections of future United States crude oil production are made by a variety of oil companies and associations, consulting firms, government agencies, and individuals. Although several projections are published on a regular schedule (i.e., those of the Gas Research institute, the Energy Information Administration, Data Resources inc., Chevron, Conoco, etc.), many appear only at crisis points or in response to proposed government initiatives affecting oil supply. Documentation of the projections is often incomplete or nonexistent, although the projections of the Energy Information Administration, the Gas Research Institute, and Data Resources Inc. are extensively documented.

OTA examined and cataloged the results of a number of projections of future crude oil supply published either in 1985, prior to the price drop, or well enough after the price drop to represent a first guess at the long-term consequences of lower world oil prices. OTA did not attempt a detailed analysis of the methodologies or assumptions of the projections, though the methodologies of many of the major models have been scrutinized in the past.

We caution the reader to be skeptical of the projections, even those made with sophisticated models. Both the simple and the complex projection methods generally rely on extrapolation from past trends to produce estimates of such important variables as the number of wells drilled in a given year. A common source of error for these methods, then, is to force them outside the range where past trends can be hoped to apply. The United States has just undergone a period during which oil prices, a key determinant of industry activity, have undergone a severe dislocation, and one in the opposite direction from past dislocations. Also, during the past few years, several companies comprising a large segment of the industry's reserve replacement capability have been restructured, merged with other companies, or been the object of takeover attempts, All these changes have serious implications for industry capabilities and business strategies. Historical relationships between industry investment behavior and economic variables such as internal cash flow may be inapplicable to the present economic environment. Finally, the period of the early 1970s to the beginning of the 1980s—when many of the relationships used by the forecasting methods were defined—was a period of extremely rapid growth in activity accompanied by hyperinflation in the costs of drilling and other factors of oil production. It appears unlikely that these relationships will prove stable.

Projections of U.S. Oil Production Made Prior to the Price Break

To keep the recent, very pessimistic forecasts of future U.S. oil production in perspective, it is important to note that a future of declining domestic production and increasing imports was widely predicted even before the sharp 1986 declines in world oil prices. In 1985, a majority of analysts expected oil prices to remain between $20 to $25 per barrel for a few years and then begin a gradual increase, in real terms, back to and beyond $30 (in 1985 dollars) by 2000. According to the Chase Manhattan Bank, a consensus view of future U.S. production u rider these conditions would have crude oil production decline from about 8.9 million barrels per day (mmbd) in 1985 to below 7 mmbd by 1995 and below 6 mmbd by 2000 (see table 2). Although three of the four other prominent forecasts in table 2 are considerably more optimistic than Chase's, all forecasts project declines from 1985 production levels of at least 1 mmbd by 2000 and 2 mmbd by 2010. Coupled with expected declines in natural gas liquids production and increases in oil demand, large increases in U.S. oil imports seemed inevitable.

As discussed later, there are alternative views of the oil resource base, and the potential of new technology to access greater portions of that base, that lead to more optimistic assessments of fu-

Table 2.—Projections of Future U.S. Oil Production, 1985 Outlook

Source	Projected crude plus condensate production (mmbd) 1990	1995	2000	2010	Price expectation (per barrel)
1. DRI	8.60		6.81	5.66	Price to $20 (1984 dollars) by 1987, stays there until 1994, up to $30 by 2000.
2. Chevron	8.30	7.60	7.60	6.90	Prices stagnant until 1990s, then rise.
3. Chase "Consensus"	8.31	6.96	5.71	NA	Price drops to low $20s (1985 dollars) by 1990, rise 0.9 percent/yr to 2000, real 2000 price below 1984 price.
4. EIA Energy Outlook	8.05	6,53	NA	NA	Price dips but is at $27 (1985 dollars) by 1990, $30 by 1995.
5. GRI Baseline	8.46	8.18	7.76	6.79	Price dips but is up to $32 (1984 dollars) by 1995 and $38 by 2000.

[a]1985 production was 8.92 mmbd

NA = Not available

SOURCES 1 *Energy Review,* winter 1985.2 Economics Department, Chevron Corp , *World Energy Outlook*, June 1985 3 Chase-Manhattan Bank, Global Petroleum Division, *World 01/ and Gas 1985,* August, 1985.4, Energy Information Administration, *Annual Energy Outlook* 1985, DOE/EIA-0383(85), February 1986 5 Gas Research Institute, *Baseline Projection* Data Book 1985 *GRI Baseline Projection of U S Energy Supply and Demand to* 2010.

ture U.S. oil production potential. These views focus particularly on the continued potential for the growth of reserves in the United States' older fields through both conventional drilling and, via improved technology, through enhanced oil recovery methods. These views, and the expectation that U.S. production could have been maintained for several more decades had prices not dropped so precipitously, are definitely minority positions. Nevertheless, the uncertainty associated with the resource base and the potential for technological innovation easily encompasses such alternative views.

Recent Projections of U.S. Oil Production Assuming Continued Low Oil Prices

Short-Term Projections

Table 3 presents 10 alternative views of the likely magnitude of U.S. oil production during the next 2 to 3 years. Few in the industry expected large reductions in annual oil production by 1986, primarily because the adverse effects of reduced drilling of exploratory and development wells would just be surfacing, and because it was felt

Table 3.—Recent Short-Term Projections of U.S. Oil Production at Low Prices

Source	Projected crude plus condensate production prices (mmbd) 1985	1986	1987	1988	Prices
1. Stolz	8.9		7.7		
2. API			8		$15
3. API			7.1		$10
4. EIA		8.73	8.52		$10 by third quarter 1986, $15 by summer 1987
5. Spears			7.9		
6. CWW		8.35	7.83		$15
7. ARCO		8	7		"low prices"
8. Chevron				7.6	
9. DRI		8.75	8.5		$15-$16
10. IPAA		8.8	8.5		

SOURCES: 1 Earl Stolz, of Howard, Weil, Labouisse, Friedrichs, reported in *Platt's Oilgram News*, Friday, Sept. 5, 1988 2. American Petroleum Institute, Two *Energy Futures. National Choices Today for the 1990s*, July 1988 (1990 production actually for 1991). 3. Energy Information Administration, *Short-Term Energy Outlook, July 1986*, DOE/EIA-0202(88/3 Q). 4. John Spears, Spears & Associates, Inc., reported in *Oil and Gas Journal Newsletter,* July 28, 1986 5 Jack L. Copeland, Copeland, Wickersham, Wiley & Co., Inc., Presentation to the Keystone Energy Futures Project: Liquid Fuels Policy, July 14, 1988.6. Robert O. Anderson, ARCO. 7. Economics Department, Chevron Corp., *World Energy Outlook, June 1986* 8. Data Resources, Inc., *Energy Review,* summer 1988.9 Independent Petroleum Association of America, "Report of the IPAA Supply and Demand Committee Annual Meeting—Dallas, TX, Oct. 26-28, 1986. "

that most operators of marginal wells would be unlikely to stop production this soon. For many marginal wells, reservoir characteristics dictate that a prolonged shutdown of production will damage future production potential; for others, stopping production will violate lease terms and result in lease forfeiture. The great majority of operators with wells of this type will hesitate before "shutting in" production because this would be essentially abandoning their investments. Thus, the production projected to be lost by year-end 1986 was expected to largely be from:

- marginal wells requiring immediate expensive repairs,
- the modest number of uneconomic wells and enhanced recovery operations that could be shut in without losing the well or the lease, and
- a small number of marginally economic operations whose owners believed that a price rebound was inevitable and therefore decided to forego small current profits for larger future profits.

The actual 1986 average production, estimated at year end 1986, was about 8.67 mmbd, down about 3 percent from 1985's average production rate. However, the daily rate at year end 1986 had sunk considerably below the average, to about 8.35 mmbd, or nearly 8 percent below the rate a year earlier.[1]

The projections for 1987 show more strongly the effects of the expected slowdown in drilling and resulting failure to compensate for natural production declines in existing wells. These projections show a very wide variation. This is partially a function of assumed price; the API projections show a 900,000 barrel per day (bbl/day) production loss in going from a $15 to a $10 per barrel oil price. Another potential reason for the variation is a disagreement about how much stripper well production and other marginal production will be shut in, primarily because the available database on the physical and economic characteristics of these wells is too weak to allow reliable projection of production losses.

Both the 1986 and 1987 projections would have been somewhat more pessimistic without widely expected increases in Alaskan oil production. Despite cutbacks at the Milne Point field, increased flows from the Kuparuk River field and the Lisburne reservoir of the Prudhoe Bay field were expected to yield 1.6-percent increases in Alaskan production in both years.[2]

Longer Term Projections

Table 4 shows 12 recent projections of longer term U.S. oil production. If the two projections with somewhat higher price tracks (GRI and Chevron B) are set aside, there is a strong consensus among the forecasters that a continuation of low oil prices will drive U.S. oil production, which was about 8.9 mmbd in 1985, to 7 mmbd or below by 1990. Coupled with expected drops in natural gas plant liquids production—the GRI projection, assuming moderately higher prices, expects a drop of over 400,000 bbl/day by 1990—these forecasts project total U.S. liquids production to drop by well over 2 mmbd by 1990. In comparison, none of the pre-price break projections (table 2) show expected production declines above 1 mmbd, and most expect a decline of about half that amount.

[1]Energy Information Administration, *Weekly Petroleum Status Report, Data for Weeks Ended: December 26, 1986, January 2, 1987*, DOE/EIA-0208(87-01)(87-02), Jan. 7, 1987.

[2]Energy Information Administration *Short Term Energy Outlook /u/\ / 986* DOE 'E IA-0202 (86/3 Q), August1986

Table 4.—Recent Projections of Future U.S. Oil Production at Low Prices

Source	Projected crude oil production (mmbd) 1990	1995	2000	Price expectation (dollars/bbl, 1986 $)
1. DRI	7.8	6.3	5.5	**$20** by 1995, $30 by 2000
2. Chevron	5.9-6.9			$10 to $15 thru 1987, $18-22 by 2000
3. API	6.2			constant $15
4. CWW	6.1			$15
5. Unocal	6-6.5			$13.50
6. Amoco	6.7		4.5	"Low Price"
7, Fisher	6.8			$15
8. Conoco A	7	5.5	3.5	<$12 thru 1995, $20 in 2000
9. Conoco B	7.8	6.9	6.1	<$20thru early 1990s, $20 in 1995, $26 in 2000
10. GRI	7.3	5.4	5.0	$12 in 1986, $14 in 1990,$21 in 2000
11. NPC	7.1	5.7	4.5	$12 in 1986, $14 in 1990,$21 in 2000
12. DOE	6.9	5.2		$14-16 thru 1990,$21 in 1995

SOURCES: 1. Data Resources, inc. Energy Review, summer 1986 2. Economics Department, Chevron Corp.,*World Energy Outlook*, June 1986 3. American Petroleum Institute, Two *Energy Futures: National* Choices *Today for the 1990s*, July 1986 (199) production actually for 1991) 4 Jack L. Copeland, Copeland, Wickersham, Wiley & Co., Inc., Presentation to the Keystone Energy Futures Project" Liquid Fuels Policy, July 14, 1988.5. Fred L. Hartley, Unocal Corp., "The High Cost of Low-Priced Oil, " submitted to the U.S. Senate Energy and Natural Resources Committee, Mar. 20, 1986.6. Economics Department, Amoco Corp., *World Energy Outlook,* Apr. 30, 1986. 7. William Fisher, Bureau of Economic Geology, University of Texas at Austin, Testimony to the Fossil and Synthetic Fuels Subcommittee, Energy and Commerce Committee, Mar. 6, 1986 8. and 9. A Coordinating and Planning Department, Conono Inc., *World Energy Outlook Through 2000,* September 1986 10. Gas Research Institute, submission to the National Petroleum Council's Survey of U.S. Future Oil and Gas Outlooks 11 National Petroleum Council, Factors *Affecting U.S. Oil and Gas Outlook,* February 1987 12 U S Department of Energy, *Energy Security A Report to the President of the United States,* DOE/S-0057, March 1987

Chapter 3
International Oil Prices: Where Are They Going?

History

The two surges in oil prices that marked the 1970s shocked a generation of oil company executives and analysts who had known decades of oil price stability. Many—though certainly not al l—of those same executives and analysts were shocked again by the sharp price drop of 1985 to 1986. The surges convinced most observers that the world was entering an era of energy scarcity, and touched off an expensive search for alternative energy sources and a new round of governmental intervention in energy markets. The price drop has served to remind us, however, that oil is a commodity, albeit one whose concentration of low cost reserves in the Persian Gulf establishes some real potentials for price manipulation . . . and, like other commodities, it may undergo periods of rapid price movements in either direction.

The era of stable prices that preceded the first price shock–l 935 to 1972–was a reflection of continuing intervention in the marketplace by both State and Federal forces and the major oil companies, with the Texas Railroad Commission (TRC) playing a critical role. The United States' leverage on the world market was made possible by the dominant role played by Texas and the United States Gulf of Mexico in world oil production during this period. In 1951, for example, world crude production was 4.3 billion barrels, of which 2.2 billion barrels, or 52 percent, was supplied by the United States. Texas' production of 1 billion barrels was 45 percent of the United States and 24 percent of the world's production. (In comparison, Saudi Arabia in its peak year produced only 17 percent of the world's oil.) Using this leverage, the TRC controlled the amount produced by Texas producers (through "prorationing") and, along with similar actions by other producing States and with Federal import restrictions, was able to balance domestic supply and demand and maintain a stable domestic price. A stable price in the United States, in turn, meant a stable world price.

For this to work, the TRC needed cooperation. Texas producers and property owners had to accept a stable price as adequate compensation for sometimes operating their best wells at less than half capacity. In addition, the other major United States producer States needed to be supportive in their own State policies. And finally, the major companies that dominated the rest of the world markets had to honor the status quo in their behavior.

In the period 1930 to 1970, the United States had a substantial surplus production capacity; in the last two decades of the period, the surplus was as high as 2 million barrels per day. in addition to the older major fields still producing in California, Kansas, and Oklahoma, there were the later, major discoveries that stretched from West Texas to Southern Louisiana, including the huge East Texas field (discovered in 1931). In the absence of restrictions on production, the price wars that were triggered by the discovery of East Texas would have continued until the excess supply had been absorbed by the financial exhaustion of the industry.

Despite these four decades of relatively stable oil markets, the long-term history of oil has been one of price volatility. Even with the inclusion of the Commission's 37 year reign, the real price of oil has swung up or down by an average of about 20 percent per year during the 125-year period of U.S. oil production.[1] More importantly, the slow but sure response of oil supply and demand to prices tended to guarantee that periods of scarcity and high prices would be followed by periods of oversupply and falling prices, and vice versa.

[1] A. R. Tussing, "How To Think About Energy Prices, " Society of Petroleum Engineers Paper No. 13193, 1984.

In retrospect, the price increases in the 1970s and the subsequent price decline and then free fall can be easily explained. In the decade or two prior to the Arab Oil Embargo and the first price shock, oil's ready availability, low price, and convenience had won it a rapidly increasing share of the world's energy consumption: from a 28-percent share of primary energy consumption in 1950, oil had risen to a 43-percent share by 1968. The rapidity of oil's rise in consumption and the absence of apparent supply problems had led oil-importing nations to ignore the fact that their consuming sectors had little fuel flexibility in the short term. With OPEC, and specifically the Persian Gulf nations, producing a large share of the oil in international trade, the importing nations were vulnerable to any artificial manipulation of supply. As a consequence, when the Persian Gulf nations wrestled control from the United States oil companies and prices began to rise in response to their manipulation of supply, the importing nations attempted to secure assured supplies by competing among themselves, thus further driving up prices.

Over the long run, however, the resulting restraint in demand and the increase in supply, natural consequences of a quadrupling of price, created an oversupply that OPEC could not manage and drove the price right back down. For example, although in the early 1970s the demand for oil seemed to display little response to the higher prices,[2] between 1979 and 1985 world oil consumption declined by 7 mmbd (13 percent) while economic output rose 15 percent. Oil's share of worldwide primary energy consumption dropped to 45 percent from 55 percent. Although a substantial part of this decline came from greater efficiency in use, much of it represented a shift to cheaper energy forms: at prices above $20 per barrel, oil often found itself at a competitive disadvantage against alternative fuels–such as coal—in

> markets for electric-utility and industrial boiler fuels, cement and brick making, distillation of water, alcohols and petroleum itself, metallurgy, the drying of materials, and every other application where the object of demand is raw calories.[3]

[2] In the United States, price controls masked the price increases.

[3] A, R. Tussing, "Oil Prices Are Still Too High, " *Energy Journal,* vol. 6, No, 1.

At the same time, there was an explosion of successful oil exploration and accelerated development of previous large discoveries which resulted in stabilization of or actual increases in production among the mature producing regions, such as the United States Lower 48 and Mexico, and the opening up of major new provinces such as the North Sea. Non-OPEC production, 26 mmbd in 1974, had surged to 37 mmbd by 1985. Coupled with the reductions in worldwide demand, the new production forced OPEC into dramatic cutbacks in its own production—a 50 percent reduction between 1979 and 1985—to prop up prices. Saudi Arabia, which bore the brunt of the cutbacks, had seen its production drop to 2.2 mmbd from a peak of about 10 mmbd. The eventual Saudi reaction to the drastic reduction in its revenues was its late 1985 doubling of production to 4.5 mmbd coupled with enactment of attractive "netback" deals[4] to consumers to assure sales. These actions caused an almost immediate collapse of worldwide oil prices. This seems, in retrospect, an almost inevitable conclusion to the pressures caused by the 1979 to 1980 price hike and the radical changes in oil supply and demand that had been set in motion 10 years earlier. And although the first half of 1987 has seen oil prices firm and rising back above $20/bbl, the potential for renewed price instability and a repeat of 1986 price levels is now an accepted "fact" in the industry.

Alternate Projections of Future Oil Prices

Before the strong upward price movement in mid-1987, there were a wide range of projections of future oil prices, but with a central theme to which many oil analysts appeared to subscribe: that oil prices would undergo a fairly brief period of instability around a relatively low mean price (perhaps $1 s, or possibly as high as $18 to $20), ranging in length from a year to perhaps 5 or 6 years, and would then begin a moderate although not inconsequential rise. The uncertainty in the timing for a settling down of prices was based primarily on differing estimations of the potential for a successful **and sustainable production agree-**

[4] A ''netbac " deal ties the price of crude to the sales price of refined products, effectively guaranteeing to the refiner a minimum profit margin on product sales.

ment in OPEC. A shorter time period was based on the thesis that OPEC members would soon see the strong self interest in reining in production and profiting from the resulting higher prices even at decreased sales volumes. A longer interlude of instability presumed that such an agreement must wait until increased worldwide demand and a significant decline in non-OPEC production, both in response to the lower prices, tightened the market. A tighter market would in turn allow an agreement to succeed with only moderate production cutbacks required among those OPEC members who traditionally have found it difficult to stay within their allowable production levels. The gradual rate of increase was based on the assumption that OPEC's, and primarily Saudi Arabia's, goal is to stabilize the market and maintain price levels that allow high production profits without stimulating excessive competition or stifling demand.

Two other price projections had a number of adherents. The first presumed that prices would stay low—at or below $1 5—long enough for higher cost production to be severely damaged or even crippled and for oil demand to increase substantially. At this time, prices would soar back to or above 1981 peak levels. These projections generally presumed a Saudi strategy of crippling its high cost competition; alternatively, an ascendance to OPEC power of the price "hawks," led by Iran, would do equally well as a baseline assumption for this scenario.

The second projection foresaw an indefinite continuation of price instability, with prices cycling about both short term events (rumors, wars, temporary production cutbacks) and long term supply and demand trends responding to changes in mean price levels. The long term cycling would generally fall inside the $10 to $20 range in today's dollars, in line with the long term average price of oil over most of its history; shorter excursions considerably above and below this level are possible and probable. This projection is based on the conclusion that oil is essentially a commodity and will follow the same unstable price paths followed by most other commodities. The $10 to $20 range is based on the loss of substantial production capacity below $10 and the large fuel substitution and conservation potential above $20.[5]

Notwithstanding the recent apparent return to a semblance of price stability, these alternative views of future prices still demand attention. In the absence of a functioning and effective institutional control of prices, the history of oil price projections has been one of abject failure. For example, a recent report[6] concludes that, during the last decade and a half, there has been a succession of strong consensuses about future prices, each clearly based on an extrapolation of price trends of the immediate past, and each dead wrong. Thus, the history of oil prices implies that policy makers would be unwise to accept the price path of the past six months as a forerunner of future prices. Also, if the "central theme" described above actually does represent a general consensus among oil analysts, a prudent businessperson or government executive should still hesitate before using it as a planning tool. Additionally, there are substantial reasons for industry spokespersons to be circumspect about their true beliefs, including competitive pressures and ongoing legislative initiatives with important implications for future industry profits.

The petroleum industry's investment decision process is guided to a considerable degree by its future price expectations and the potential for profits they imply.[7] A reasonable way to guess industry's true belief about future prices is to examine its behavior, although interpreting recent behavior is difficult because the past several months and the coming year or so represent a transition period with a high "noise" component. Nevertheless, drilling costs are now quite depressed, and the potential profit from many longer term prospects would be very high it oil prices were to rebound near the time when production could

[5] For a more detailed examination of future price trends, see J.J. Schanz, Jr. and L.C. Kumins, *The Many Faces of Oil*, Congressional Research Service Report No. 86-1 36S, July 24, 1986.

[6] *The Future of Oil Prices: The Perils of Prophecy*, D. Yergin, J. Stanislaw, B. Kates-Garnick, and I .C. Bupp, Cambridge Energy Research Associates and Arthur Andersen & Co., CERA 497-6446, 1984.

[7] Although decisions about the overall magnitude of spending depend as well on capital availability, and particularly on the industry's Internal cash flow.

be brought on line. Despite this, the industry has been showing lessened interest in drilling for prospects that have a delayed prospect, as demonstrated by the drop in exploratory drilling offshore. Consequently, this may indicate that most producers are not confident that prices will increase significantly within a few years, and perhaps not even within 5 or 6 years. Unfortunately for the reliability of this conclusion, however, the industry's investment behavior is also a response to its recent poor cash flow and earnings, which would tend to focus investment onto projects which can add quickly to cash flow.

Determinants of Future Oil Prices

An examination of the factors influencing current and future oil prices shows a mixed picture with regard to pressures for high or low price levels. In general, arguments for a future of high oil prices focus on the immediate depressing effects of low prices on oil and gas exploration and development and subsequent expected declines in future supply, the likely increases in oil demand in response to current prices, the tremendous financial incentives for OPEC nations to cooperate with one another in limiting production, and finally the concentration of basic oil resources within OPEC and especially within the Persian Gulf. Arguments for continued low prices, or for instability centered around a low price level, focus on the entrenchment of oil use efficiency in the economy, the availability of cheaper substitutes for oil, especially natural gas, at prices above $20, the low marginal production costs and low replacement cost for much of the world's

Table 5.—"Why Oil Prices Will Remain Low"- Arguments Used by Forecasters of Low Future Oil Prices

1. The current worldwide excess of producing capacity is larger (absolutely and relative to consumption) than during the late 1960s and early 1970s, and the worldwide Reserves to Production ratio is just as high.
2. The diversification of major oil producing countries is considerably greater than when OPEC established market control. In addition, the concentration of commercial control in a few multinational firms no longer exists.
3. Natural gas, given its availability, can readily substitute for more than half of world oil use, and can potentially substitute for much of the rest. Also, availability is becoming less of a problem. Natural gas resources and producing/distributing capacity have exploded since the early 1970s. Since 1973, global gas reserves have increased by the energy equivalent of 30 years of OPEC oil production. The United States has gone from apparent shortage to surplus, Europe's available supply has exploded, and West Africa and the Middle East can displace oil in space heating, industry, and electric generation if delivery systems can be built.
4. Coal capacity and delivery systems are in surplus.
5. A large percentage (some say more than half) of the existing fossil electric generating capacity—and virtually all of the new capacity—has dual fuel capacity.
6. Despite current low prices, oil consumption still is likely to stagnate because oil intensity is controlled by the replacement of facilities and equipment and the substitution of goods and services . . . and this will continue to be in the direction of the less efficient to the more efficient, and more oil intensive to less oil intensive. This tendency will be reinforced by consumer skepticism about the stability of low oil prices.
7. Contrary to conventional wisdom, world oil production capacity is not likely to decline dramatically in the face of lower oil prices; it may even be able to increase over time. In the past, higher prices had the perverse effect of depressing investment in new capacity in low cost areas, where most of the world's known reserves occur. At lower prices, these nations will be more likely to seek to increase capacity in order to maintain revenues. (Likely candidates for expansion include Kuwait, Iraq, Mexico, and Saudi Arabia) Also, initial declines in drilling have spurred many current and prospective producing countries towards greater flexibility in their dealings with oil companies, and this should lead to expanded investment.
8. Also, the costs of replacing oil and gas reserves have followed prices down, primarily because many of these costs were inflated during the drilling boom and are now at distress levels. The production levels in the so called high-cost regions will not suffer as much as is supposed as investors become better aware of the new cost/price relationships.
9. Oil prices do not occur in a vacuum, and oil will not readily recapture the markets it lost when oil prices soared, because prices for natural gas and coal will follow oil prices down in order to compete and retain the markets they now have.
10. Importing nations are in a far better position now than in the past to beat down attempts by OPEC to create artificial shortages and raise prices. In particular, strategic reserves and agreements on oil sharing will serve as buffers. In addition, past experience has taught the importers some important lessons about strategic behavior, especially about the futility of seeking to attain unilaterally assured supplies at the expense of other nations. Nor will they, given the uncertainty about price behavior, be willing to risk too much on a dependency on low oil prices as a permanent condition.
11. Arguments about declining supplies ignore the strong potential for new technologies and expanded knowledge. For example, producers are likely to push development of new cost-saving technologies to allow them to prosper in a low-price environment.
12. The 1973 to 1985 period was an anomaly as far as oil prices are concerned; during the entire 125-year period of oil production, prices averaged less than $15 in today's dollars. Thus, $15/bbl or less is likely to be the world long-term oil supply price.

Table 6.— "Why Oil Prices Will Increase"- Arguments Used by Forecasters of High Future Prices

1. Past successes in exploration provided the Middle East with known oil reserves, both developed and undeveloped, well beyond the immediate needs of this region given their current rate of production, Outside of the Middle East, on the other hand, there is little excess production capacity and far less undeveloped reserves. This imbalance in both present and future production capacity, coupled with the worldwide slowdown in exploration and development caused by current low prices, and with the dominance of the Middle East in undiscovered resources, will lead inexorably to a resumption of OPEC market control and, subsequently, to higher prices.
2. Oil demand is bound to increase during a period of low prices, planting the seed of future market tightening. Although the demand increase will not mirror the decrease caused by high prices, any expectations that our interest in energy efficiency and other energy savings is "locked into" the energy system are as incorrect as were past expectations that high levels of growth in oil demand would continue despite high prices.
3. Low prices have already begun to stifle oil production in high cost areas; failure to continue intensive exploration will result in substantial losses in worldwide producing capacity within a few years.
4. An increase in demand for OPEC oil of only about 5 mmbd caused by demand growth and loss in non-OPEC production capacity (or drop in production in cooperation with OPEC) would restore OPEC's leverage in its efforts to influence world oil prices.
5. Expectations that the availability of natural gas as a substitute boiler fuel will provide a buffer to oil price increases ignore the likely declines in gas production capacities as a result of the overall slump in drilling, especially in the United States, and, elsewhere, the difficulty—and great expense—of building the gas transmission infrastructure needed to allow effective competition with oil.
6. The incentive for OPEC nations to manipulate production—i.e., the potential to maximize revenues over time because price increases can be balanced against lower sales volumes—is sufficiently high, and sufficiently well understood, to eventually lead to a higher level of cohesion and cooperation within OPEC.

oil, and the historic inability of cartels to sustain high prices. Tables 5 and 6 summarize the arguments for low and high oil prices.

Clearly, these differences in the alternative views of future oil prices are based in large part on differences in judgments made about the response of supply and demand to price, as well as on the expected actions of major players such as the OPEC nations. The major uncertainties in the direction that future prices will take are the following:

1. the response of oil demand to lower prices;
2. the possibility of increases in production capacity in the low cost oil regions[8];
3. the uncertainties in OPEC actions, based on uncertainties about the underlying motives of the Saudis, if any, the potential for the "hawks" to gain control of OPEC and to seek higher prices immediately, and the ability of the OPEC nations to maintain production discipline;
4. the potential for new oil disruptions; and
5. the future levels of non-OPEC production, including the uncertain ability of supposedly high-cost oil producing regions to find an answer to maintaining production levels in a low and unstable price environment.

[8] High oil prices and the attempt to control supply actually led to stifling expansion of productive capacity in the low-cost oil regions; most investment went into relatively high-cost regions. Some analysts now speculate that the reverse could happen at low oil prices.

Chapter 4

What Will Determine Future Production?

Introduction

There is widespread agreement among oil industry analysts that United States oil production is likely to drop substantially in the coming years if oil prices remain at or near their current low levels. As noted earlier, the production decline would come from the combined influence of the closing of thousands of wells and enhanced oil recovery (EOR) projects whose production costs are too high, reduced levels of drilling of production and exploration wells, cutbacks in new EOR projects, and a slowdown in technology improvement with reduced R&D spending.

The logic of these predictions appears generally correct. For one thing, the evidence "on the ground" right now is extremely supportive of a long-term decline in U.S. production; the overall level of activity in development drilling, in all phases of exploration, in enhanced oil recovery, and in R&D *have* undergone a drastic decline, the existence of natural production declines in existing wells is simply indisputable, and monthly domestic oil production has already dropped by nearly 8 percent over a one year period.[1] Second, many of the companies involved in drilling, well servicing, and other aspects of oil exploration, development, and production have suffered serious financial reversals as a result of the loss of revenue associated with the price drop and the decline in oilfield activity, and their ability to maintain previous levels of activity has suffered as well. Third, the large drop in prices would appear to have an inevitable adverse effect on the economics of drilling and other production prospects, thus sustaining the decline in activity and the current trend towards lower production. And fourth, the variety of available projections of future U.S. oil production have used several different approaches, yet they have arrived at similar conclusions about a substantial production drop.

However, there is considerable uncertainty about the *magnitude* of a production decline, and there are even some grounds to question the idea that the decline must be very large. Before acquiescing to the view of inevitable and large production declines, policy makers should ask whether recent forecasts of future oil production are basically reliable, and should examine carefully the assumptions underlying the pessimistic projections. In OTA's view, there are important questions about the accuracy of these projections, because of changes to the industry that the projections have not taken into account, because of basic uncertainties about key aspects of oil supply responses to price changes, and because the nature of the price changes that have occurred are outside the experience of forecasters. In the following discussion, OTA outlines the concerns about the forecasts, and then reviews some of the primary factors that should be taken into account in projecting future production. OTA does not attempt to arrive at any "most likely" rate of future U.S. oil production. *OTA cone/udes, however, that the available evidence, although incomplete, points strongly to a continuing, and substantial, decline in U.S. oil production if oil prices remain well below $20 per barrel.*

The Reliability of Forecasts of U.S. Oil Production

Despite the variety of their level of detail and specific analytical approaches, most forecasts of future oil production can be divided into two basic categories: those that rely primarily on applying relationships (e.g., between production revenues and drilling rates) discovered by examining the historical record of oil exploration, development, and production and those that rely on economic analyses of expected exploration, development, and production opportunities. The two forecasting methods are not mutually exclusive; all economic analyses include the application of some historical analysis.

The great majority of forecasts made available to the public and to Congress use historical rela-

[1] A drop ot 680,000 bbl/day in domestic crude production, from December 1985 to December 1986, in Energy Information Administration, *Short-Term Energy Outlook. Quarterly Projections*, January 1987, DOE,' EIA-0202(87/1Q)

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tionships to project future U.S. production. In general, forecasts of this type are particularly vulnerable to errors caused by applying the relationships outside a relatively narrow band around the independent variables. Such forecasts basically are extrapolations from past trends, and remain valid only when the degree of extrapolation—represented by the changes in the independent variables—is small. Current and expected future conditions affecting the oil industry, however, represent considerable changes from past conditions. In fact, as discussed in several of chapters below, there are good reasons to believe that straightforward extrapolation of past trends in several areas—e.g., in the way companies decide how much of their revenues to allocate to exploration and development—will give inaccurate results. Consequently, extrapolative methods now appear to be working well outside of their range of reliability. In OTA's view, forecasts of U.S. oil production based on *uncritical* acceptance of the results of extrapolative methods are an unreliable basis for policymaking.

Forecasts that rely primarily on direct economic analyses of exploration, development, and production prospects may appear more reliable because they are more closely tied to the decision process used by the oil industry. However, such forecasts cannot escape entirely from the problems associated with extrapolating from historic trends; they may use historic data to simulate the industry's method of selecting drilling prospects or budgeting its overall E&D programs, or to estimate certain key variables such as the success rate of wildcats. In addition, the economic analyses are likely to use proprietary data on oilfield opportunities, preventing the access to analytical scrutiny necessary for credibility. Although some of the forecasts of major oil companies may be based on a careful economic analysis of drilling prospects, the assumptions and detailed methodologies behind these forecasts are not available for review. The possibility that some companies have unannounced agendas will, deservedly or not, undercut the credibility of their forecasts. Finally, the reliability of forecasts based on economic analyses demands an accurate assessment of the geologic resources that may be accessed by the industry within the time frame of the forecast. OTA believes that the reliability of resource assessments—especially at the level of detail needed for economic analysis—is inherently low.

Factors Affecting Future Oil Production

In discussing why they believe that U.S. oil production will fall, and fall drastically, in the years to come if world oil prices remain both low and volatile, oil analysts have stressed a number of forces driving the predicted decline. Most have stressed that drastically lowered industry revenues have crippled the industry's ability to recover its past capital investments and pay off its loans, severely damaging the industry's financial health. Some analysts stress in addition (or instead) that the basic economics of E&D investment have been damaged severely by lower oil prices, in other words, that it is no longer profitable to conduct much of the drilling and other E&D activity that was attractive at higher oil prices.

The precise role in industry investment decisionmaking of cash flow, on the one hand, and E&D profit prospects on the other is by no means a settled issue. Some analysts are convinced that cash flow is the critical determinant of the magnitude of E&D investment, and that profit prospects primarily shape only the *nature* of that investment. Indeed, many analytical models of investment spending and drilling use cash flow as the key parameter. Other analysts are equally convinced that cash flow will *not* be the primary determinant of future industry investment, at least for the longer term, that the basic economics of drilling will be the key driving force. A correct assessment of the roles of each of these factors will be critical not only to projecting future production but also to determining effective policy actions to combat a production decline.

Aside from cash flow and the economic prospects for new investment, additional factors that will affect future oil production levels include:

- *the potential for premature loss of some existing production with high operating costs;*
- *the nature of the oil resource base,* which is intimately linked to the economic prospects for new investment because it determines the physical character of available investment opportunities;

- *the current surplus of gas deliverability,* which discourages gas drilling and can hurt the economics of some oil drilling;
- *structural changes in the oil industry* that have increased debt, altered the industry's likely business strategy and objectives, and are likely to affect industry efficiency;
- *changes in the "efficiency" of exploration and development activity* (as measured by factors such as the reserves found per well and the success rate of exploratory drilling), which will alter the historic relationship between E&D activity levels and their results in terms of reserves found and production capability added;
- *changes in the climate for oil investments in the United States and overseas* that will influence company decisions about dividing E&D investment budgets between the United States and overseas;
- *prospects for technological change in the industry,* and especially the potential for cost-saving technology to help the industry successfully adapt to an environment of low prices; and
- *the damage to the oilfield service industry,* which might hamper attempts at a drilling rebound if oilfield investment prospects improve.

The following chapters discuss these factors, where possible drawing conclusions about the direction and likely magnitude of their effect on future production levels.

Chapter 5

Economic and Resource Factors Affecting U.S. Oil Production

The Profitability of New Investment in Oil Exploration, Development, and Production

Introduction

As noted previously, there is a basic disagreement among analysts of the oil industry about whether it is the prospective profits of new investments in exploration and development (E&D) activity or **the revenues flowing into the industry from its previous E&D investments, that is, cash flow, that are the key determinant of the magnitude of the industry's future** E&D investments. This question is complicated by the substantial changes in the industry's management and structure that have been wrought in the 1980s, and the as-yet unknown long-term effects that the new oil price environment will have on industry investment decision making.

In the short term—perhaps for **2** or **3** years—the level of cash flow from past investments and the effect it has on the industry's basic financial health seems likely to have a very strong effect on the level of new investment **even if prospects for profitable investments are basically good.** Many of the financial entities generally responsible for U.S. drilling and other production activities have been hurt badly because of the large cut in their revenues. Because these companies may hold land positions that could yield profitable drilling opportunities but no longer have adequate financial resources, new investment will suffer from a mismatch between opportunity and capability. Over the course of the next few years, however, loans will be renegotiated, companies will be restructured, and properties will be sold; many of the companies will go under, but those remaining should be stronger financially. Eventually, investment dollars will be made available to the industry **if there are attractive investment opportunities.** Thus, **the long-term outlook for oil supply is dependent on the basic profitability of the oil exploration and development prospects available to the industry.**

In OTA's view, it is by no means obvious that the potential profitability of the industry's available investment possibilities in exploration and development have sunk in lockstep with oil prices. Because the costs of oilfield services had escalated so sharply during the late 1970s and very early 1980s, there was considerable room for deflation in these costs when oil prices began to slide in 1981, and in fact these costs continued to deflate into 1986.[1] Only a careful examination of the balance of development costs and the oil revenues that will flow from incurring these costs will yield a true picture of the likely future of the industry in the face of continuing low oil prices. If the basic prospect economics are not as bad as they seem at first glance, there may be some real potential for industry activity levels—and reserve additions and production potential—to begin to rebound within a few years.

An evaluation of the potential profitability of domestic oil production prospects available to the U.S. oil industry would be invaluable in projecting the likely future levels of reserve replacement and production for the United States. For a variety of reasons, such an evaluation is not readily available. First, there is no reliable inventory of the available prospects, although a partial inventory (particularly of development prospects) could be assembled from drilling data and lease and field inventories in databases managed by groups such as Dwight's, NRG Associates, and others. A particular difficulty here is the substantial uncertainty associated with the size and characteristics of the remaining oil resource base. Second, much of the information necessary to do economic analysis, as well as extensive analyses of new prospects carried out by oil companies and their consultants, are proprietary. Third, were the necessary data available, the complexity of the evaluation would be very great, in part because of the large site-to-site variations among the

[1] Although drilling costs rose briefly in 1985, according to the 1985 Joint Association Survey.

many thousands of prospects, and in part due to the complexity of the government taxes and regulations (e.g., the windfall profits tax) that strongly influence the profitability of the prospects.

To OTA's knowledge, there are no widely accepted, regularly updated evaluations of the potential profitability of new investments in oil E&D. There are, however, a number of sources of information and analysis that can provide some important insights about potential profitability:

- Industry comments: The oil companies conduct evaluations of profitability for their own properties and those properties they might wish to purchase, and most companies have recently undertaken extensive reevaluations in light of the new price environment.

  These evaluations are strictly proprietary, for obvious competitive reasons. However, a number of industry planners have been willing to discuss the **general results of these analyses with** OTA.
- **OTA economic analyses:** OTA has sponsored a limited series of economic analyses of potential oil exploration and development programs, in order to evaluate some of the claims of our industry contacts and to evaluate the impacts on profitability of alternative government policies, changes in expected oil prices, and improvements in efficiency.
- **Supply models using economic evaluation:** A few computer models of oil supply contain submodels that conduct economic evaluations, but these are very general in nature and appear unlikely to capture the full range of effects of the price drop. The Hydrocarbon Model used by the Gas Research institute contains an economic analysis package with one of the more detailed models of the oil and gas resource base, and the results of model runs can be useful in gauging changes in profitability; however, the model does not evaluate improved recovery of gas- and oil-in-place, an important factor in future reserve additions and production.
- **Analyses of one or a few types of investment:** A number of analysts have published results of individual profitability analyses for specific projects or areas. In addition, a few groups have conducted detailed economic analyses of some components of E&D activity. These include the Minerals Management Service's analyses of the U.S. Outer Continental Shelf resources and the National Petroleum Council's study of Enhanced Oil Recovery.[2]
- **Media statements:** Some industry executives have stated an oil price or price range that they claim is necessary to revive drilling or stabilize production, but these statements are essentially impossible to evaluate and they adopt different assumptions about costs, interest rates, future prices, and other critical variables . . . if they are indeed the result of actual analysis.

in addition, an examination of how drilling and other E&D costs may change over time will give further insight into how prospective profitability may change in the future.

Survey of Industry Analysts

Despite industry secrecy, some oil company analysts have offered to OTA some general information on the profitability prospects of new oil and gas E&D investment.

Essentially all of these analysts contend that the "inventory" of profitable oil and gas prospects has shrunk enormously at mid-1986 price levels of $12 to $15/bbl despite substantial declines in drilling costs and significant though lesser declines in other costs. One source estimates that only about 10 to 15 percent of the opportunities available at early 1980 prices remain available at $12 to $15/bbl. This figure is in line with the results of the IPAA/SIPES drilling survey, which shows an 80- to 85-percent drilling decline at $13,[3] and an API survey predicting an 83-percent decline (by 1991) at $10.[4] Although some companies claim that there are large numbers of economic prospects at these prices, most are said to be quite small and do not in the aggregate offer a major opportunity to replenish reserves. A

[2]National petroleum Council, *Enhanced Oil* Recovery, June 1984.

[3]Survey of their memberships conducted by the Independent petroleum Association of America and the Society of Independent Professional Earth Scientists.

[4]API Crude Oil Price Effects Survey, May 1986, compiled by Coopers and Lybrand for the American Petroleum Institute, results in API, *Two Energy Futures: National Choices Today for the 1990s, 1986* edition, July 1986.

very common theme is that the only arena that can support substantial drilling levels is relatively low risk, low-to-moderate cost development drilling, primarily for oil objectives (because gas markets are poor), with short lead times. This implies that most drilling will involve step-out (extension) and infill drilling, primarily at shallow depths, in areas with little risk of cost overruns or curtailments (for gas prospects). Other categories of prospects still viable at $12 to $15 include:

- continuation of projects where the majority of front-end capital has already been spent (enhanced oil recovery, offshore development drilling, and waterfloods that have passed the early development stages);
- projects that are necessary to maintain company positions, e.g., development and exploratory drilling needed to satisfy lease requirements, and joint ventures with substantial performance penalties; and
- projects with very distant production start-ups, if the company is confident of higher future oil prices. Although a few companies are continuing a portion of their long-term projects, more commonly these are being canceled despite company projections of "inevitable" long-term price increases.

A common and disturbing theme is that exploratory drilling is virtually dead at $12 to $15. A limited number of high-grade exploration prospects are said to remain economic, such as shallow pressured objectives,[5] and the shallow Gulf of Mexico. However, the bulk of high reserve potential prospects, both exploratory and development, are thought to be no longer economic. These include:

- Beaufort and Bering Seas, and most other frontier exploration;
- deep gas prospects;
- heavy oil offshore California (but some development projects with large sunk costs will continue);
- deepwater Gulf of Mexico;
- higher cost enhanced oil recovery, especially "grassroots" projects; and
- Overthrust Belt exploration.

It has been reported in the trade press that there is little agreement in the industry about the crude price necessary to stimulate a drilling recovery, with some saying that $20/bbl would generate significant new activity and others that $35/bbl is necessary.[6] Most of our contacts were pessimistic that an increase to $18 to $20 oil prices would in any sense "rescue" the industry, although all admitted that significant additional prospects would become economic. These were said to include:

- some deepwater Gulf of Mexico exploratory prospects;
- considerable onshore wildcat drilling;
- additional enhanced oil recovery projects, especially select second-generation CO_2 projects with available CO_2 supplies, and some polymer projects;
- exploration and delineation drilling in the Beaufort Sea;
- limited offshore California development; and
- many waterflood projects, whose economic threshhold prices are-often between $15 and $20.

Although virtually all contacts would agree that there would be significantly more drilling activity at the $18 to $20 price, there was very substantial disagreement about the effect on reserve additions at that price. The more optimistic companies foresaw a considerable reduction in the rate of decline of reserves, for example, from a 9 to 12 percent/year decline at $12 to $15 to a 5 to 7 percent decline at $18 to $20. Other companies saw little improvement in reserve additions with a moderate price increase. Part of the disagreement may rest on the type of additional drilling activity foreseen at the higher price, with the pessimists possibly being skeptical that this price will elicit the high risk drilling they believe is necessary for the addition of important new reserves. All, however, agreed that a critical factor was price stability, which can be just as important as price level. Without stable prices, decisions on prospects will require either higher threshold rates of return or the functional equivalent, the need to satisfy profitability thresholds at prices substantially below the "expected" levels.

[5] That is, shallow drilling objectives with reservoir pressures above the pressure caused by the weight of the rock, requiring lower-than-average pumping energy for production.

[6] "Fiscal 1985 Returns for OGJ400 Mixed," in *Oil and Gas Journal,* Sept. 8, 1986.

OTA Economic Analyses of Drilling Opportunities

OTA Prospect Analyses of Hypothetical Drilling Prospects.—OTA[7] has examined the potential profitability of some hypothetical onshore drilling prospects, focusing in particular on how profitability has changed over time, using a commercial economic analysis software package[8] and additional software developed by our contractor. The analysis evaluates both development and exploration prospects.

The development drilling prospects are 2,000, 4,000, 8,000, and 12,000 ft onshore wells with "per well" drilling and operating costs averaged across several geographic areas. The perspective is from the viewpoint of a driller who has a land position and must determine whether or not to drill.[9] The basic cost assumptions used in the analysis are summarized in table 7.

For each well, OTA calculated the profitability **expected** at the time of drilling—1972, 1981, 1985, and 1986–and, for the earlier years, the profitability **actually obtained.** The "expected" calculations used price scenarios generally reflective of price forecasts of the time (see table 8);[10] the "actual" calculations used historic prices for west Texas crude to 1985, and then adopted a price scenario assuming, in 1986 dollars, a $14/bbl price through 1990 and then a gradual increase to $20/bbl in 2000. For windfall profits tax calculations, OTA assumed that the wells were "Tier 3" wells, i.e. wells drilled on properties or into reservoirs that were not producing before 1980. Drilling and other costs were based on Energy Information Administration compilations of cost data for the relevant years. The key well parameters, initial production rate and reserves **per well, were selected by calculating the values needed to allow a 15 percent before tax real rate of return in 1986, assuming the $14/bbl price scenario.**

Table 9 shows the (before tax) rates of return for the four drilling dates and expected/actual price paths. Although the precise results apply only to the particular cases evaluated, the consistency of the results as well depth varies and

[7]Analysis by Thomas Garland, OTA contractor, Dallas, TX.

[8]The OGRE I I Oil and Gas Reserve Evaluation System analysis packdge developed by David P. Cook & Associates.

[9]For a longer term view of drilling economics, front-end bonuses must be added to total capital costs.

[10]OTA recognizes, however, that there has not been at any time a universal consensus about future prices, nor is it necessarily true that the price expectations actually used in oil company prospect analyses were similar to those made public. For example, although OTA used a level price, in constant dollars, for the 1972 expected case, some operators claim that they had expected to see increasing real prices at that time. For those operators, our calculated rates of return for the 1972 expected case are too low.

Table 7.-Assumed Costs To Drill, Equip, and Operate Development Wells, Selected Years

	Depth			
Year	2,000 feet	4,000 feet	8,000 feet	12,000 feet
Average equipment ***cost per well (less*** tubing ***costs):***				
1972	21,690	29,074	39,121	30,143
1981	58,625	75,381	109,830	98,407
1985	54,278	70,413	98,396	82,154
1986	51,564	66,893	98,396	82,154
Average operating costs ***per well/yr:***				
1972	3,541	4,456	5,701	6,803
1981	9,976	13,227	16,530	22,914
1985	11,512	14,810	18,840	27,142
1986	10,594	14,070	17,898	25,784
Average oil well drilling ***costs:***				
1972	35,187	68,039	151,839	484,827
1981	144,598	296,037	705,519	2,113,390
1985	93,440	204,444	483,200	1,242,816
1986	74,752	227,555	386,560	994,253
Average dry ***hole drilling costs:***				
1972	23,164	43,682	94,383	318,824
1981	114,753	236,737	541,811	1,622,440
1985	68,320	145,600	321,778	992,448
1986	54,656	116,480	257,422	793,958

SOURCE: Energy Information Administration data.

Table 8.—Oil Prices for West Texas Crude (current dollars per barrel)

	1972	1975	1980	1981	1982	1983	1984	1985	1986	1988	1990	1995	2000
1972 actual	3.48	7.64	21.84	35.06	31.77	29.35	28.87	26.80	14.00	15.14	16.38		
1972 expected (4.6)[a]	3.48	3.98	4.99	5.22	5.46	5.71	5.97	6.24	6.53	7.15	7.82		
1981 "actual"				35.06	31.77	29.35	28.87	26.80	14.00	15.14	16.38	24.24	35.89
1981 expected (7)				35.06	38.64	42.38	46.93	51.72	57.01	69.24	84.10	136.74	222.34[b]
1985 "actual"								26.80	14.00	15.14	16.38	24.24	35.89
1985 expected (4)								26.80	27.04	27.40	28.07	38.54	53.00
1986 expected (4)									14.00	15.14	16.38	24.24	35.89

[a]... is the assumed inflation rate, percent.

[b]In 1981 dollars, $62/bbl.

NOTE: For "actual" cases, oil price is assumed to be $14/bbl (1986$) from 1986-90, gradually inflating to $20/bbl (1986$) by 2000. In other words, OTA deliberately assumes a "low oil price" scenario.

SOURCE: Office of Technology Assessment, 1987.

Table 9.—Economic Analysis of Drilling Prospects: Development Wells in Reservoirs Not Producing Before 1979 ("Tier 3" oil)

Depth (feet)		2,000	4,000	8,000	12,000
Initial production (bbl/day)		14	23	44	97
Reserves (bbl)		30,000	51,000	102,000	230,000
Year	Scenario	Real before tax rate of return (percent)			
1986	$14/bbl Oil	14.6	14.3	14.8	15.1
1985	Expected	52.0	44.0	41.5	35.2
	"Actual"	22.2	18.3	16.5	15.1
1981	Expected	42.9	38.2	32.2	22.6
	"Actual"	27.0	22.0	16.5	7.6
1972	Expected	Loss	Loss	Loss	Loss
	"Actual"	9.1	11.3	13.3	9.6

SOURCE' Office of Technology Assessment, 1987.

our examination of the regional variations in drilling costs lead us to believe that the general trends apparent in the results apply to a considerably broader set of oil development prospects.

The critical patterns apparent in the results presented in table 9 are as follows:

- At every depth, the expected profitability for 1986 is substantially lower than the expected values for both 1981 and 1985. Although drilling costs have declined substantially from previous years, many drilling prospects that appeared profitable in the early 1980s would not be drilled in 1986 **even if capital were available.** This tends to confirm, at least qualitatively, the claim made by most in the industry that a substantial part of the inventory of formerly economic prospects are now untenable.
- Because price expectations in both 1981 and 1985 were unrealistically high, the **actual** profitability of the drilling prospects would have been much lower than expected. In most cases, actual 1981 and 1985 profitability would have been similar to the expected 1986 profitability, which is based on quite modest price expectations.
- At every depth, prospects that would be considered profitable in 1986 would have been expected to be outright losses in 1972, before the initial price shock. This result is especially interesting because some analysts have likened 1986 conditions to 1972 conditions, concluding that U.S. production is likely to fall as quickly as it had been falling in 1972. Based on our results, these expectations may seem overly pessimistic. However, our analysis does not consider the availability of good drilling prospects. Most analysts would argue that, despite advances in technology and geologic knowledge since 1972, the availability of good physical prospects in 1972 was superior to that of 1986.
- Despite the substantial fall in prices between 1981 and 1985 and the reduced expectations for future price increases, the prospects looked somewhat more attractive in 1985. The improvement in profit expectations stems from the substantial decline in drilling costs between 1981 and 1985.
- Taking a longer term perspective, of an operator deciding whether to purchase and develop an unleased property, requires adding lease bonuses to the capital costs used in the analysis. This would tend to narrow the range of profitability between the different years, because bonuses typically are higher when profit expectations are higher, pulling down the profit from the prospects with the best potential. As discussed previously, the current slowdown in drilling activity gives the bargaining advantage to the operator, and lease bonuses for new property are likely to be low. Thus, the potential profitability of buying and developing a property in 1986 will be closer to the potential profitability of the same prospect in 1981 than the values shown in table 9.

Aside from the baseline analyses, we conducted a number of sensitivity runs to examine the effects of changing assumptions.

Table 10 shows the effect on profitability of drilling in an "old" reservoir rather than one

Table 10.—Economic Analysis of Drilling Prospects: Development Wells; Effect on Profitability of Windfall Profits Tax "Tiers"

Type of producer: independent
Wells: same physical parameters as in table 9.
Date of first production: 1981

	Real rate of return (before tax) (o/o)			
	"Actual" prices		Expected prices	
Depth (feet)	Tier 3	Tier 1	Tier 3	Tier 1
2,000	27.0	21.1	42.9	34.2
4,000	22.0	17.1	38.2	29.8
8,000	16.5	12.8	32.2	25.1
12,000	7.6	5.2	22.6	17.3

SOURCE: Off Ice of Technology Assessment, 1987

which was not producing prior to 1980. Because the tax rate is higher for old, "Tier 1" oil, and the "windfall profits" higher because of previous price controls on the oil, the profitability of the Tier 1 prospects would have been considerably lower than otherwise identical Tier 3 ("new oil") prospects. As shown in the table, both the actual and expected rates of return were substantially lower for the Tier 1 drilling prospects. In fact, for the deepest prospects, the expected profitability for 1981 is little different than the expected 1986 profitability. This effect would be exaggerated for major companies, because the windfall profits Tier 1 tax rate is 70 percent for majors and only 50 percent for independents (the results in the table are for independent drillers).

Table 11 illustrates the strong effect of expected oil prices on expected profitability. For every case, a price drop to $10/bbl transforms a modestly profitable prospect into a disaster, whereas a $20 price transforms the prospect into a handsome one. The strongly negative effect of the $10 price is particularly important because several of the exploration managers and planners interviewed by OTA claimed that drilling prospects were being subjected to a "low price hurdle, " i.e., being rejected unless they would remain profitable under the lowest price foreseeable . . . with the hurdle price often set at about $10. The effect illustrates the potential value of a government-legislated price "floor"; even if such a floor did not affect actual prices,[11] it might encourage drilling by raising the hurdle price required for drilling prospects, presuming that the companies trusted the government not to remove the floor if world prices fell well below it. Also, of course, the strongly positive effect on profitability of the $20 price implies that a mechanism to raise oil prices could have significant positive effects on drilling. The ultimate value of such a mechanism cannot be judged, of course, without a reliable analysis of how much drilling—and how much additional reserves and production capacity—would be created by each additional dollar in the oil price.

[11]Except, perhaps, by discouraging exporters from selling at below the floor, since the eventual landed price would be taxed up to the floor anyway.

Table 11 .—Economic Analysis of Drilling Prospects: Effects of Oil Price on Rate of Return Tier 3 Development Wells, Drilled and Production Begun in 1986

	Real rate of return (before tax) (o/o)			
Oil price ($/bbl)	2,000 ft	4,000 ft	8,000 ft	12,000 ft
20	41.3	37.2	34.3	33.0
14	14.6	14.3	14.8	15.1
10	Loss	Loss	1.3	3.49

SOURCE: Off Ice of Technology Assessment. 1987

The price sensitivity calculations were made assuming drilling costs would not change within the price range examined. This is likely for the $10 case because current costs are so low that there is little room for downward movement. If $20 oil generates substantial new drilling activity, however, drilling prices might rise somewhat, reducing profitability.

Table 12 illustrates the effect on profitability of changing drilling costs, for a single 4,000 ft development well. As discussed in the section on costs, drilling costs have gone through a classic boom and bust cycle during the last decade or so, and some analysts fear that a substantial rebound in costs could occur if drilling activity begins to pick up. Conversely, substantial improvements in drilling technology have occurred over the same time period, although the effects on costs of the improvements were submerged by the imbalance between demand for and availability of drilling services. Continuing technology improvements could keep costs down if the industry accepts fully the challenge of finding and producing oil in a low price environment.

The results show that the movement in drilling costs from the 1985 average ''per well' costs to

Table 12.—Economic Analysis of Drilling Prospects: Effect of Changing Drilling Costs on Rate of Return

4,000 ft. development well, Tier 3
Initial production = 23 bbl/day
Reserves = 50,000 bbl
Drilled, production begins in 1986
$14/bbl oil price

	Rate of return (o/o)	
Drilling cost	Before taxes	After taxes
1985 average	8.1	7.8
10°/0 below 1985	10.8	10.1
20°/0 below 1985	14,3	12.8
30°/0 below 1985	18.5	15.8

SOURCE: Office of Technology Assessment, 1987.

30 percent below the average–which has occurred in some areas—approximately doubles the rate of return, a substantial effect.

Finally, table 13 illustrates the effect on profitability of changing Federal and State tax policies to ease tax burdens on the industry, as has been called for by numerous industry spokespersons. As shown clearly by the results, a moderate easing of taxes—adding investment tax credits, raising depletion allowances, and cutting State severance and ad valorem taxes—does improve the 1986 expected profitability of these wells, but only modestly.

In addition to the analyses of development prospects, OTA examined the comparative profitability over time of a series of exploration and development programs that find and develop small oilfields (each field requires five producing wells for full development) in known producing provinces. The wildcat wells in the program are successful in one out of six attempts; development wells are assumed to be 80 percent successful. Well costs, expected oil prices, and other economic variables are assumed to be the same as in the previous analysis, except that geophysical and other costs associated with exploration wells are assumed to add 20 percent to the total costs of these wells.

Table 14 displays the rates of return (real, before taxes) associated with the exploration and development efforts at 2,000, 4,000, 8,000, and 12,000 ft, with and without lease acquisition costs included.[12] A constant (real) $20 oil case is included to show the effects of an import tariff set at this level. In contrast to the earlier effort, only "expected" rates of return—associated with typical oil price expectations of the time—are shown for the 1972, 1981, and 1985 cases. The table also shows the per well initial production rate and reserves necessary to obtain a 15 percent before-tax real rate of return for 1986.

The rates of return results are very similar to the previous analysis for development well drilling: at every depth, prospects that would be considered profitable (15 percent before-tax real rate of return) in 1986 would have been expected to be outright losses in 1972 and, in contrast, considerably **more** attractive in 1981 and 1986, whether or not lease acquisition costs are in-

[12]Values for lease acquisition costs were obtained from the Congressional Research Service analysis described below, see table 17.

Table 13.—Economic Analysis of Drilling Prospects: Policy Options for Improving the Profitability of Development Drilling

Same physical parameters as in table 9
Date of drilling and first production: 1986
Expected price = $14/bbl
Type of producer: small independent

	Real after tax rate of return (o/o)			
	2,000 feet	4,000 feet	8,000 feet	12,000 feet
1. 1986 tax system	13.27	12.75	12.73	12.78
2. Change investment tax credits				
a. to 200/0	14.16	13.44	13.30	13.19
b. to O (new law)	12.08	11.83	12.05	12.33
3. Allow 80°/0 depletion limit.	13.38	12.80	12.74	12.78
4. Cut severance and ad valorem taxes from 100/0 to 50/0	15.56	14.71	14.39	14.33
5. Allow higher depletion allowance:				
200/0 of gross.	14.00	13.53	13.50	13.50
300/0 of gross.	14.35	14.15	14.26	14.25

SOURCE: Office of Technology Assessment, 1987.

Table 14.—Economic Analysis of Exploration and Development Projects

Well depth, feet	2,000	4,000	8,000	12,000
Initial production rate, bbl/day/well	20	35	71	172
Reserves, bbl/well	41,000	72,000	146,000	377,000
Initial year	Expected rates of return, real before tax, percent			
A. Without ***lease acquisition costs:***				
1986 $20/bbl oil	38	34	33	30
1986 $14/bbl oil	15	14	15	15
1985	45	39	38	33
1981	35	31	27	21
1972	Loss	Loss	Loss	Loss
B. With ***lease acquisition costs:***				
1986 $14/bbl oil	9	8	9	9
1985	30	25	25	21
1981	21	18	16	12
1972	Loss	Loss	Loss	Loss

SOURCE Office of Technology Assessment, 1987

eluded. Also as in the previous analysis, expectations of a constant $20 oil price from 1986 on will boost expected profits to the same general range as the 1981 and 1985 prospects. This result lends some credibility that an import tariff set to produce a minimum $20 domestic price might do some good, at least for this sort of "small target" drilling and assuming that drillers (and their investors) trust the Federal Government to maintain the tariff even if world oil prices were to plunge.

Comparing the initial production rates and reserves needed to produce a 15 percent return between this exploration case and the earlier development drilling case demonstrates that exploration requires better prospects than development to achieve the same return. Although this only confirms the obvious—the exploration program must pay off the high cost of multiple dry holes (and buying the lease), whereas for incremental development drilling this cost is "sunk"-it serves to bolster the industry's contentions that exploration drilling will absorb substantially greater cuts than will development drilling.

The "dry hole risk" is crucial to the economics of exploratory drilling. Although technological optimists have often predicted large reductions in this risk, and in certain situations this has been accomplished, improved technology has been essentially unsuccessful in boosting the **industrywide risk in any measurable way, Table 15** shows how such a boost might effect the economics of exploration programs, by examining how the rate of return would shift if the wildcat success rate shifts from one new field discovery in six attempts to two or three discoveries in six attempts. As shown in the table, an improvement to a 50 percent success rate would double the rate of return for the type of exploration program examined in this analysis. Unfortunately, most oil producers would view such an improvement as a more appropriate topic of science fiction than of scientific analysis. Nonetheless, the results illustrate the value of pursuing improvements in the efficacy and cost of seismic and other exploration techniques.

Prospect Analyses Conducted for OTA by the Congressional Research Service. -Jane Gravelle, Specialist in Industry Analysis and Finance, and Bernard Gelb, Analyst in Industry Economics, both of the Economics Division of the Congressional Research Service, have conducted a ser-

Table 15.—What Happens If Dry Hole Risk Is Reduced? ($14/bbl oil, no lease acquisition costs)

	Well depth, feet			
	2,000	4,000	8,000	12,000
Success rate	Expected rates of return, real before tax			
1:6	15	14	15	15
2:6	20	19	20	20
3:6	29	29	30	33

SOURCE Office of Technology Assessment, 1987 ies of economic analyses for this study.[13] The analyses are of a series of combined exploration/development programs hunting for relatively small fields in four producing regions: the Permian Basin, Powder River Basin, Anadarko Basin, and the Gulf Coast Basin of Offshore Louisiana. The exploration/development programs are described in tables 16 and 17. As in the OTA analysis described above, the same physical prospects are evaluated for four different years: 1972, 1981, 1985, and 1986. The oil prices used in the analyses generally conform to the price expectations of the times (table 18), except for 1986, which uses three hypothetical price scenarios. Only the "expected" profitabilities are examined, since decisions to drill are made on the basis of such expectations.

The prospect evaluation employs a discounted cash flow analysis, with revenues and costs discounted to the present, to arrive at estimates of "net present value''—the amount that the net after-tax revenues (gross revenues less operating costs, royalties, and all taxes), discounted to the present, exceeds the initial investment. In the baseline runs, the lease acquisition costs were not included, primarily because these costs are so variable from project to project. The real discount rate was set at 10 percent, so that when the net present value is zero, the project earns a real (i.e., corrected for inflation) 10 percent rate of return. Table 19 presents the tax and financial variables used in the analyses.

The results of the baseline series of prospect analyses are presented in table 20, with the results displayed in the form of the net present value expressed as a percent of the initial investment. If a real 10 percent rate of return is considered the minimum "hurdle rate" of a prospect–the minimum expected profitability that would convince the operator to proceed with the program —then the 1972 Powder River Basin project, with zero net present value, could have proceeded if the operator did not have to pay a lease bonus (unlikely) or if he had paid the bonus already and, perhaps on the basis of new information, reevaluated the property to arrive at the expected result displayed in the table. Prospects with positive net present values allow the operator some leeway to pay bonuses, with the amount determined primarily by the competition for properties and the land's potential for some alternative use that might be hindered by a drilling program.

The results are generally similar to those of the OTA analysis of development and exploration

[13] B.A. Gelb and J.G. Gravelle, "Oil Prospect Profitability in the United States: Estimated Expectations in 1972, 1981, 1985, and 1986," CRS Report No, 87-38E (revised), Mar. 24, 1987.

Table 16.—Characteristics of Hypothesized Prospects

Variable	Producing region and type of operator: Permian Basin Independent	Powder River Basin Major	Powder River Basin Independent	Anadarko Basin Independent	Offshore Louisiana Major
Number of wells:					
Dry	10	10	10	10	6
Successful	10	10	10	10	13
Well ***depth (feet):***					
Dry	8,500	6,400	6,400	3,300	8,800
Successful	8,900	6,100	6,100	3,300	8,900
Initial year production:					
(thousands of barrels)	222	169	169	48	1,450
Annual physical depletion:					
(percent)	10	10	10	10	10

NOTE: The Permian Basin is mainly in Texas; the Powder River Basin, in Wyoming; and the Anadarko Basin, in Kansas. Except for well depths, the data shown refer to each individual prospect as a whole.

SOURCES AND METHODS OF ESTIMATION: Number of holes (wells) —Based on Congressional Research Service (CRS) geologist's field experience and industry rules of thumb regarding: a) ratios of dry holes to successful wells holes; and b) the typical number of producing holes for a reasonably profitable prospect. The ratio of successful holes to dry holes for the offshore prospect is higher than onshore because the much higher cost of drilling offshore forces operators to be more cautious in drilling "wildcat" wells. Well depth—Typical well depths of the respective producing regions in 1972, based on data from the Joint Association of Drilling Costs, published by the American Petroleum Institute. Offshore wells are assumed to be drilled in 100 feet of water, and production platforms to have 12 "slots," Initial year production-Derived by CRS from the relationships among total industry production, outlays (for exploration, development, and production), and reserves for a "normal" year. Based on data from the Annual Survey of Oil and Gas, compiled and published by the U.S. Bureau of the Census. Annual physical depletion—Based on actual ratio of total U S crude oil production in a year to proved reserves.

Table 17.—Estimated Investment and Operating Costs (thousands of dollars)

		Producing region			
		Permian Basin	Powder River	Anadarko	Offshore Louisiana
Geological and geophysical	1972	12% of sum of drilling plus lease and well equipment			
	1981				
	1985				
	1986				
Land acquisition and leasing[a]	1972	25°)0 of sum of drilling plus lease and well equipment			14,400
	1981	33°/0 of sum of drilling plus lease and well equipment			16,416
	1985	25°/0 of sum of drilling plus lease and well equipment			3,000
	1986	20°/0 of sum of drilling plus lease and well equipment			1,500
Drilling	1972	2,424	1,775	436	9,680
	1981	11,956	6,753	1,851	50,929
	1985	10,140	5,165	1,436	28,571
	1986	7,600	3,850	1,080	21,150
Lease and well equipment	1972	293	325	153	2,170
	1981	1,155	872	575	6,200
	1985	1,145	935	520	6,200
	1986	1,090	890	495	5,830
Annual operating costs	1972	50	49	27	742
	1981	142	142	82	2,417
	1985	165	152	93	2,360
	1986	164	151	92	2,300

aNot includedin the estimation of expected profitability

SOURCES AND METHODS OF ESTIMATION Geological and Geophysical average ratio— derived from data in the Annual Survey of Oil and Gas, compiled and published by the U S Bureau of the Census Land Acquisition and Leasing—Onshore: Ratios for 1972 and 1981 derived from data in the Annual Survey of 011 and Gas, ratios for 1985 and 1966 estimated by authors, based on price expectation scenarios. Offshore: Derived from average lease bonuses paid per acre in Federal offshore lease sales Drilling —Assumed number of wells Onshore—10 dry, 10 pay; offshore—6 dry, 13 pay. Drilling costs estimated from Joint Association of Surveys on Drilling Costs published by the American Petroleum Institute, for 1972, 1981, and 1984, from the 1985 Survey of Combined Fixed Rate Overhead Charges for Oil Producers, published by Ernst and Whinney, and from comments by an oil industry association economist Lease and Well Equipment—Estimated for 1972 1981, and 1985 from data in Costs and Indexes for Oilfield Equipment and Production Operations in the United States, published by the Energy Information Administration, estimated for 1986 based on comments by Energy Information Administration industry expert. Annual Operation Costa-Same as for lease and well equipment

Table 18.—Assumed Crude Oil Prices

Producing region	1972	1981	1985	1986
	Price per barrel in initial year (initial year dollars)			
Permian Basin	$3.35	$35.90	$26.00	$14.00
Powder River Basin	3.30	35.90	28.00	14.00
Anadarko Basin	3.25	35.90	25.50	14.00
Offshore Louisiana	3.55	36.00	27.25	14.00
	Anticipated annual change as of initial year (constant dollars)			
All producing regions	No change	A) +2°/0 indefinitely B) See note	1985-90: –3.00/0 After 1990: +2.5°/0	A) 1985-90: + 8% After 1990: +2°/0 B) 1985-90: O°/o After 1990: 3.5°/0 C) 1985-90: O°/o After 1990: 0°/0

NOTE: Anticipated annual changes for 1981 price scenario "6'' -1981 to 1985: – 0.80/0; 1985 to 1990 + 8 20/0, 1990 to 1995: +6.5°/0, 1995 to 2000 + 2 3°0, 2000 to 2020 + 0.9%. Initial year price for 1981 price scenario "B'" asumed to be $34 per barrel for all producing regions

SOURCES Initial year prices based directly and/or indirectly on data from the Energy Information Administration, U.S. Department of Energy, Petroleum *Supply Annual, Monthly Energy Review,* and *Annual Energy Review* Anticipated changes based directly and/or indirectly on Projections by the Energy Information Administration and by several private organizations, including oil companies, energy industry groups, and other organizations

Table 19.—Tax and Financial Variables

	1972	1981	1985	1986[a] Old	1986[a] New
Interest rate	8.20/o	16.0%	12.7%	10.2%	
Inflation rate	4.60/o	9.6%	4.0%	4.0%	
Debt share	17.0%	17.0%	17.0%	17.0%	
Federal Income Tax Treatment					
Rate	48.0%	46.0%	46.0%	46.0%	34.0%
Intangible drilling costs	Expensed	Expensed	Expensed*	Expensed*	Expensed+
Losses	Expensed	Expensed	Expensed	Expensed	Expensed
Equipment					
Investment credit rate	10.0%	10.0%	10.0%	10.0%	0
Tax Life (years)	9.2	4.5	4.5	4.5	7
Depreciation method[b]	SYD	150 DB	150 DB	150 DB	DDB
Reduction in basis	No	No	1/2	1/2	No
Depletable costs[c]	Percentage depletion	cost depletion	cost depletion	cost depletion	cost depletion
State Tax Treatment					
Severance Tax					
Louisiana	.078**	.125	.125	.125	
Texas	.046	.046	.046	.046	
Wyoming***	.03	.04	.015-.06	.015-.06	
Kansas	0	0	.08	.08	
Income Tax					
Louisiana	,04	.08	.08	.08	
Texas	0	0	0	0	
Wyoming	0	0	0	0	
Kansas	.0675	.0675	.0675	.0675	

[a]Old refers to Federal tax law in effect in 1986. New refersto the Tax Reform Act of 1986, which became effective in ?987.
[b]SYD—Sum of years digits; 150 DB—150 percent declining balance; DDB—Double declining balance
[c]22% percentage depletion for 1972.
+Thirty percent of costs of majors amortized over five years.
*Twenty percent of costs of majors amortized over three years.
"'The Louisiana severance tax wasa per unit tax of26 cents per barrel in 1972. The rate equivalent in the table would decline overtime.
***The Wyoming severance tax rises to 6 percent after 1989, but is currently 15 percent
NOTE: Because of data limitations, it was not possible to incorporate local property taxes. Application of the windfall profits tax depends on price levels,

SOURCES: inflation and interest rates are basedon lagged values following Patrick Hendershott and Sheng-Cheng Hu, "Investment in Producer's Equipment;'How Taxes *Affect Economic Behavior,* Herrry Aaron and Joseph A. Pechman (eds.), Brookings institution, Washington, DC, 1981, p. 85-128, Debt ratios are from Don Fullerton and Roger Gordon, "Afle-examination of Tax Distortions in General Equilibrium Models,'' *Behavioral Simulation Methods in Tax Policy Analysis*, Martin Feldstein (ed.), National Bureau of Economic Research, Universityof Chicago Press, 1983, p 372.

Table 20.—Estimated Anticipated Profitability of U.S. Oil Prospects 1972,1981,1985, and 1986 (net present value as a percent of initial investment)

Initial year and price scenario	Producing region and type of operator: Permian Basin, Independent	Powder River Basin, Major	Powder River Basin, Independent	Anadarko Basin, Independent	Offshore Louisiana, Major	Unweighted average
1972	7	0	0	–4	16	4
1981A	74	113	113	86	97	97
1981 B	74	114	114	84	97	97
1985	60	119	120	72	142	103
Old Tax Law:						
1986 A	21	49	50	13	66	
1986 B	14	39	40	6	51	28
1986 C	1	24	24	–7	29	
New ***Tax Law:***						
1986A	25	59	60	14	79	
1986B	17	46	48	6	60	33
1986 C	1	28	29	–10	34	

NOTE Real discount rate assumed to be 10 percent,

SOURCE: Congressional Research Service, 1987 wells, but the regional detail provided by the CRS analysis yields some interesting insights. The expected profitability of the hypothetical prospects in mid-1986 was lower than the expected profitability in 1981 or 1985, but generally higher than in 1972—precisely as in the OTA analysis. Even if future oil prices are assumed to rise quite rapidly (8 percent per year in real dollars, as in price scenario 1986A), and despite a sharp drop in drilling costs between 1985 and 1986, expected profitability in 1986 is appreciably lower than in 1985 for all five prospects. However, in the Permian and Anadarko Basins, under the 1986B prices (identical to those used in the OTA analysis), the expected profitability for 1986 is only modestly better than it was in 1972, If the $14 oil price is assumed to hold, except for rising with the cost of living, the 1986 prospects are slightly inferior to the 1972 prospects in these basins.

The Permian and Anadarko Basins correspond to regions JS and JN in table 24 (in the next section), which displays the relative development prospects computed by GRI's Hydrocarbon Model. That model calculated the prospects for both these regions to be quite good. These results are not necessarily contradictory, because the Hydrocarbon model runs incorporated relatively optimistic assumptions about oil prices.

In addition to the cases discussed above, CRS examined the effects on prospect profitability of the Tax Reform Act of 1986 (which will take effect starting in 1987). A most surprising result is that the new tax rules show a small but significant **improvement in profitability over the current tax law in every prospect, for every price scenario. Apparently,** the lower tax rates in the new law override the effects of losing the investment tax credit. This conclusion would likely not hold for a company that had excess tax credits or an actual net loss under the current law (because the lower tax rates under the new law would be irrelevant), nor does it account for any adverse effects of the alternative minimum tax in the new code. It will hold, however, for situations where the decision to pursue the prospect is at the margin where the company is deciding whether to pursue one more prospect, and the company does not have excess tax credits or a net loss for the year. In OTA's view, this is the decision most worth examining, since it is the one faced by most companies trying to decide whether to increase their rate of drilling . . . and thus it is the decision that, made in the aggregate, will determine whether a drilling rebound is likely to occur.

CRS also examined the effects of a $10/bbl and $20/bbl expected (real) price, an assumed repeal of all State severance taxes, a 20 percent refundable tax credit for drilling costs (costs which are currently in the nature of intangible drilling costs, and which exclude depreciable equipment and depletable geological and geophysical costs), and a 27.5 percent oil depletion allowance.[14] The results are displayed in table 21.

The results for the $10 and $20 oil price and the cut in severance taxes are pretty much the same as those arrived at in the OTA analysis. The $10 price–which is particularly significant since conservative industry analysts may use this price as a "hurdle" price for profitability—creates a disastrous drop in profitability. The $20 price, which simulates a variable import tariff set at this value, boosts profitability substantially. (However, it drilling costs were to increase as a result of revived activity, the boost in profitability would be partially offset.) The cut in severance taxes has only a modest beneficial effect in most regions (the Louisiana offshore prospect is an exception), and does not appear capable **by itself** of making a substantial difference in industry activity.

An interesting exercise is to compare the results of the $20 price case to the 1981 and 1985 results, because drilling in these two years was at a high level (even though the 1985 rig count was somewhat depressed). The net present values at $20 oil were back to 1981-85 levels for all regions but the Anadarko, implying that an import tariff set at this level might spur a significant drilling rebound **if the oil companies trusted the Federal Government to leave the tariff in place AND if sufficient capital were made available to the independent producers.** Of course, confidence in such a result would require an examination of a far wider set of cases than was accomplished here. Also, we stress that this result does **not** imply that a return to a free market price of

[14] All of the cases incorporate the new tax rules.

Table 21 .—Estimated Anticipated Profitability of U.S. Oil Prospects, Under Specified Price and Policy Alternatives (net present value as a percent of initial investment)

Price or policy alternative	Producing region and type of operator: Permian Basin, Independent	Powder Major	River Basin, Independent	Anadarko Basin, Independent	Offshore Louisiana, Major	Unweighted average
$10/bbl constant price[a]	–14	6	7	–25	6	–4
Variable import tax setting price at $20/bbl[a]	53	102	103	44	120	84
20°/0 drilling cost credit[b]						
1986A	41	73	74	26	93	
1986 B	32	61	62	18	74	47
1986 C	17	42	43	2	48	
No State severance taxes						
1986A	30	65	66	24	106	
1986B	21	52	54	15	85	42
1986C	5	29	31	– 3	54	
27.5°/0 depletion allowance						
1986A	39	76	77	29	105	
1986 B	29	64	65	20	84	49
1986 C	11	44	45	1	53	
27.5°/0 depletion allowance, with old tax law						
1986A	40	76	77	33	103	
1986 B	31	64	65	25	84	51
1986 C	15	44	45	8	55	

[a]Prices are per barrel of crude oil Estimation procedure for import tax assumes that the price of domestic oil would equal that Of imported oil.
[b]Under this option, Federal income tax liability for a tax year would be reduced by an amount equal to 20 percent of expenditures for drilling in that year
[c]Under this option, Federal income tax liability for a tax year would be reduced by an amount equal to 27.5% of gross income from the property.

NOTE Except where Indicated, the estimates have been made using the provisions of the new tax law,

SOURCE: Congressional Research Service, 1987,

$20 might also accomplish a drilling rebound. It is the **expectations of future prices as much as the current price that drives industry activity, and the current volatility of prices will tend to undermine industry confidence.**

The 20 percent drilling credit, an idea not explored in the OTA prospect analysis, does produce a moderate improvement in profitability in all cases, and could prove interesting to policymakers who favor using the tax code to boost E&D activity.

The 27.5 percent depletion allowance also provides a moderate improvement in profitability in all cases. in general, it boosts profitability slightly more than the 20 percent drilling credit.

Inclusion of lease acquisition costs in the analyses will tend to make the 1985 and 1986 results look more favorable in comparison to the 1981 results, because 1981 was the height of the drilling boom and lease acquisition costs were especially inflated. As evident from table 17, these costs have come down considerably in recent years, especially in the offshore.

Table 22 presents the net present values for the same cases as in table 20, as well as for the $20 oil case, with the lease acquisition costs incorporated in the analysis. Inclusion of these costs changes none of the basic conclusions obtained from examining table 20, but the results do demonstrate more decisively than the original analysis that 1985 was actually a very attractive time to drill, that reduced oil revenues were often more than compensated for by reduced costs.

Analyses by the Gas Research Institute (G RI)

GRI operates an energy supply and demand forecasting system called the Hydrocarbon Model that incorporates a detailed description of the United States Lower 48 oil and gas resource base, on a field-by-field basis, and an economic analysis model that assesses the expected profitability of exploratory and development drilling based on the characteristics of the resource opportunities. GRI's Strategic Analysis and Energy Forecasting Division has recently conducted a spe-

Table 22.—Estimated Anticipated Profitability of U.S. Oil Prospects 1972, 1981, 1985, and 1986 With Lease Costs Included (net present value as a percent of initial cost, including lease acquisition costs)

Initial year price scenario	Producing region and type of operation: Permian Basin, Independent	Powder River Basin, Major	Powder River Basin, Independent	Andarko Basin, Independent	Offshore Louisiana, Major
1972	–12	–18	–18	–21	–46
1981A	34	64	64	43	58
1981 B	34	65	65	42	58
1985	31	80	80	41	125
1986A	3	27	28	–4	58
1986 B	–3	18	19	–lo	43
1986 C	–14	5	5	–21	26
$20 Constant Price	30	72	73	22	109

SOURCE Office of Technology Assessment based on Congressional Research Service analysis, 1987

cial run of the Hydrocarbon Model aimed at evaluating the effects on oil and gas production of low oil prices.[15]

The primary assumptions used for the analysis were:

- oil price (1986$) of $11.76/bbl in 1986, rising to $14.41 in 1990 and $21.60 in 2000; gas prices of $1.47/mmBtu, $l.60, and $2.95, respectively;
- 1986 drilling costs 10 percent below 1985 levels; and
- producers accept a minimum real rate of return, after tax, of 7 percent.

Some characteristics of the model and the assumptions used will tend to drive the estimates of oil and gas production both above and below a "most likely" level. For example, factors that would tend to overestimate supply include:

- The minimum rate of return, 7 percent, appears low. This rate is lower than the rate used by GRI in its baseline (higher price) runs. Most industry analysts expect that the perceived instability of oil prices will raise the minimum rate of return acceptable to the industry.
- The drilling model does not consider the availability of capital as a constraint, implicitly assuming that capital will be made available to the industry if there are acceptable drilling prospects to pursue. For at least the short term, a lack of capital is an important constraint on industry activity, especially among independent producers.

Factors that would tend to underestimate supply include:

- The model does not include the effects on supply of enhanced oil recovery and other activities to improve the recovery of oil- or gas-in-place.
- Actual 1986 drilling costs may be as much as 30 percent below 1985 level's, and not the 10 percent assumed in the model run (however, many operators do not expect costs to remain this low for long).

The results of the model run, displayed in table 23, show oil production declining at a 5 percent/yr rate through 1990, then 3.1 percent/yr rate through 1995, and a 1 percent/yr rate through 2000. Gas production holds constant through 1990 and then declines at about 1.2 percent per year through 2000. Development drilling is projected to dip considerably and remain at levels substantially lower than those of the early

Table 23.—Lower-48 Oil and Gas Production (excluding increased recovery from old fields)

Year	Oil[a] (million bpd)	Gas (tcf)[b]
1985	6.63	16.1
1990	5.13	16.1
1995	4.36	15.1
2000	4.16	14.3

[a]Does riot include lease condensate
[b]Trillion cubic feet

SOURCE T J Woods and P D Holtberg, "Hydrocarbon Activity in an Era of Low Oil Prices," 61st Annual Technical Conference and Exhibition of the Society of Petroleum Engineers, New Orleans, Louisiana, Oct. 5-8, 1986 SPE Paper 15355 Congressional Research Service, 1986.

[15]T. J. Woods and P.D. Holtberg, "Hydrocarbon Activity in an Era of Low Oil Prices," 61st Annual Technical Conference and Exhibition of the Society of Petroleum Engineers, New Orleans, LA, Oct. 5-8, 1986, SPE Paper 15355.

1980s—e.g., 32,500 total development wells in 1990 versus the rate of 50,000 to 70,000 wells per year sustained during the first half of the 1980s, (Part of this dip may be attributed to the model's exclusion of drilling designed to increase recovery efficiency in known fields.) On the other hand, exploratory drilling is projected to dip initially and then recover sharply, to nearly 14,000 wells/yr in 1990 and 23,000 wells/yr in 1995 versus 13,000 to 17,000 wells/yr during the early 1980s. This latter result is surprising because of the greater costs generally associated with exploratory drilling and the widely held industry opinion that most future drilling will focus on field development and away from exploration.

The model shows Lower 48 crude oil (not including lease condensates) production declining by 1.5 mmbd by 1990 and 2.3 mmbd by 2000 (from 1985 production). As shown in chapter 3, of the forecasts prepared in 1985, with expectations of stable oil prices in the low-to-mid $20s for the remainder of the 1980s, the most pessimistic—the EIA Energy outlook—projected a 0.9 mmbd reduction in **total United States crude plus condensate production[16] by 1990, with only 0.7 mmbd attributable** to Lower 48 production. The Chase "Consensus" forecast projected only a 0.6 mmbd drop for the United States as a whole. The EIA projection for 1995 is for a 2.4 mmbd drop in total United States production, with 1.9 mmbd attributable to Lower 48 production, whereas the Chase projection for the total United States is for a 2 mmbd drop. Thus, on the surface, the GRI results imply a substantial decline in future oil production attributable solely to the projected difference in prices between the moderate 1985 expectations and a lower price scenario based on an extension of 1986 price levels. However, the authors of the GRI papers describing this analysis do not themselves interpret these results so pessimistically, because they believe that greater recovery of oil-in-place—not incorporated in the model—will compensate for much of the projected reduction in "standard" oil production. They attribute the current drilling decline primarily to the immediate effects of the large drop in the oil industry's cash flow and conclude that the overall resource economics of drilling have not been greatly affected by the price drop.

[16]Presumably, lease condensate production will decline when natural gas production declines, so that the projected total decrease in crude plus condensate production implies a lesser decrease in crude alone.

Aside from the overall production projections, the GRI model exercise yields interesting insights into other potential changes associated with the 1986 price drop. In particular, the exercise yields insights into the viability of new drilling activity, and the profits likely to be gained from earlier activity, in different portions of the country. For example, the model results indicate that the extensive drilling in the early 1980s to all depths in southern Louisiana, to 5 to 15,000 feet in the Texas gulf coast, and to 10 to 15,000 feet in the Permian Basin are yielding poor economic returns, and new drilling in these area/depth combinations should drop sharply with continuing expectations for unacceptable rates of return or even outright losses. On the other hand, prospects for new drilling in many region/depth combinations remain surprisingly good despite the lower prices, including offshore California, especially in shallow water (less than 600 ft), onshore California to O to 10,000 ft, the Rocky Mountains and Northern Great Plains to all depths above 15,000 ft, and several other regions. Table 24 shows the economic prospects for drilling in the Hydrocarbon Model regions based on the low price exercise.

MMS Analysis of the Effect of Lower Oil Prices on OCS Recoverable Resources

A reduction in oil exploration activity on the Outer Continental Shelf (OCS) and the statements of industry planners imply that many OCS exploration prospects that were economic in the early 1980s at oil prices in the $25 to $35 price range are not economic at $15 or $18. This in turn indicates that the total recoverable oil resource was diminished by the recent oil price decline.

The Minerals Management Service (MMS) of the Department of the Interior has evaluated the effect of varying oil price on the magnitude of the undiscovered "leasable resources" in the Outer Continental Shelf (leasable resources are resources that would be profitable to explore for and develop). Table 25 presents MMS's estimate

Table 24.—Economic Prospects for Drilling, Based on GRI Hydrocarbon Model Runs

	Region	Prospects
A	(Ohio, Kentucky, Tennessee, Georgia further east and offshore)	excellent* at 0-10,000 ft (established depths), good to poor at greater depth
B	(Mississippi, Alabama, Florida)	good to excellent shallow and deep, poor at 5,000-10,000 ft (most common drilling interval)
c	(Minnesota, Wisconsin, Michigan, Iowa, Illinois, Indiana, Missouri)	marginal
D	(Arkansas, North Louisiana, Central Texas)	good at 0-10,000 ft (most common drilling interval), marginal to poor below
E	(South Louisiana)	poor at 0-15,000 ft, marginal at greater depth
G	(Texas Gulf Coast, South Texas)	good to excellent at 0-5,000 ft (high past active drilling), marginal 5,000-15,000 ft (most common drilling interval), poor at greater depths
HI	(Dakotas, Nebraska, Montana, Wyoming, Idaho, Colorado, Utah, Arizona, New Mexico)	good to excellent at 0-15,000 ft, marginal at greater depth
JN	(Mid-Cent-KanSaS, Oklahoma, Texas, RRD #lo)	good at 0-5,000 ft, and greater than 10,000, good to excellent at 5,000-10,000 ft
JS	(Permian Basin, Southeast New Mexico, Texas RRD 7C,8,8A)	good at 0-10,000 ft, greater than 15,000 ft, marginal 10,000-15,000 ft
L	(California, Nevada, Pacific North West)	excellent at 0-10,000 ft (most common drilling intervals), poor to marginal at greater depths
EGO	(West Gulf, offshore Louisiana and Texas, shallow offshore Alabama, Mississippi deep Norphlet)	good at all water depths except uncertain in Norphlet trend
LO	(Offshore California and Pacific North West)	excellent at 0-600 ft. water depths (most common drilling interval), good beyond 600 ft

* Definition of Terms Poor = below 5 percent real after tax rate of return; Marginal = 5-10; Good = 10-15; Excellent = above 15

SOURCE Off Ice Technology Assessment, based on GRI data

of leasable resources in 22 planning areas for United States Gulf of Mexico oil prices of $17, $23, $28, and $34/bbl[17] in January 1987.

The analysis indicates that a 50 percent drop in price yielded a 34 percent decrease in leasable resources overall, but that, in some basins (Beaufort Sea, St. Georges Basin, Chukchi Sea, and others), 100 percent of the resource was rendered uneconomic. Presumably, some of the basins were lost because the level of recoverable resources dropped below levels necessary to support the costs of required transportation systems or other minimum fixed costs.

A reliable evaluation of the effect of the OCS resource "loss" on U.S. oil production requires a detailed examination of the individual basins and the various governmental and industry plans for developing these basins. However, it appears likely to us that in most cases the effects on production of the loss at the $17 price will be small within this century, because of the long time lag–generally a decade or so–between OCS initial leasing and initial production, and because generally the higher cost resources would not be foremost on most development schedules anyway. Of course, this conclusion will not hold when the total loss in leasable resources becomes larger . . . as will certainly happen at prices substantially below $17.

OTA does not believe that the MMS analyses are necessarily relevant to projecting the incentives for exploratory drilling aimed at very large, long-term frontier prospects. Many or most major companies will pursue such prospects regardless of current prices because they cannot project prices for the time frame of actual development of any potential discoveries (in most cases, beyond 10 years) and they cannot pass up the chance of discovering a field that is so large it can be profitably developed at almost any conceivable oil price.

[17] With an assumed 1 percent annual real price growth.

Table 25.—Sensitivity of Leasable Resource Amounts to Current Oil Price

1987 U.S. Oil Price/bbl Gulf of Mexico	Leasable resources, million barrels of oil equivalent			
	$17	$23	$28	$34
Planning area:				
Western Gulf of Mexico	3,790	4,490	4,630	4,630
Central Gulf of Mexico	3,930	4,070	4,110	4,110
Southern California	540	730	880	880
Navarin Basin	0	180	720	790
Middle Atlantic	90	110	230	230
South Atlantic	250	410	680	770
St. George Basin	0	0	260	260
Eastern Gulf of Mexico	180	330	420	470
Chukchi Sea	0	0	0	400
Beaufort Sea	0	0	250	310
Northern California	150	280	410	410
North Atlantic	10	30	30	70
Central California	110	180	220	220
Washington/Oregon	50	50	60	60
Gulf of Alaska	0	0	0	30
North Aleutian Basin	0	0	0	20
Norton Basin	0	0	0	20
Kodiak	0	0	0	0
Florida Straits	0	10	10	10
Hope Basin	0	0	0	0
Shumagin	0	0	0	0
Cook Inlet	0	0	0	0
Total	9,100	10,870	12,910	13,690
Percent of $34 resource	660/0	79 "/0	94%	100%

SOURCE: U.S. Department of the Interior, Minerals Management Service, 5-Year Outer Continental Shelf Oil and Gas Leasing Program for January 1987-December 1991, app. F, draft

costs

The cost components relevant to a particular decision about exploration, development, or continued production depend on the precise circumstance of that decision:

- In deciding whether to continue production from an **existing well in good operating order, only the net production costs–called the "lifting costs"—are considered. The cost of acquiring the lease, finding the oil, drilling the production well, and building the necessary infrastructure such as pipelines** are important to the company's profit and loss sheet, but these costs are "sunk" and should not enter the specific production decision; production will continue as long as the net revenues from the well's production exceed the lifting costs. For wells needing significant repairs, the amortized cost of these repairs must be added to lifting costs, and the sum balanced against revenues.
- Decisions to expand production by drilling **new wells in known fields** need to consider the expected lifting costs plus the cost of drilling the well, including a risk factor to account for the possibility that the well could be dry. If the well is drilled outside the known boundaries of a reservoir, i.e., a new pool test or an extension test, the risk component could be quite substantial.
- Adding production from a **new** (as-yet-undiscovered) **field requires considering the costs of acquiring the lease, drilling a number of exploratory wells to discover the field, drilling development wells, and, at times, adding significant infrastructure.**

Finally, many decisions must be made at stages intermediate to these cases . . . for example, the decision whether to drill exploratory wells after the lease is acquired. Such intermediate decisions are forced on producers when economic conditions change suddenly, disrupting the previous calculations that led to the initial phases of oil-field activity.

In other words, at any instant, the oil industry has a large "inventory" of potential investment opportunities ranging from unleased, unexplored land with potential oil reserves that are only a gleam in a geologist's eye, to older fields with a few remaining undrilled sections, or with some potential for infill drilling (drilling at a closer spacing than was initially planned) or other production-enhancing investments. For the older fields, most or all of the leasing, exploration, and infrastructure costs have already been incurred. Thus, it is inherently cheaper to pursue a prospect in the most developed areas, and becomes progressively more expensive—in terms of incurring expenses for lease bonuses, seismic exploration, laying pipelines, etc.—to pursue prospects at earlier and earlier stages of the production cycle. The only reasons why undeveloped prospects are pursued at all are because the inventory of prospects in known and partially developed fields is limited and must be replenished, and because the company believes it will find more profitable oil or gas wells–with more reserves, higher production rates, higher quality oil, with less water cut and lower operating expenses–than in the more developed areas.

Lifting Costs.—As noted above, decisions to continue production from existing wells are dependent on lifting costs remaining below the revenues flowing to the producer, that is, total revenues less royalties and taxes[18] **must exceed costs. Thus,** when oil prices are $15/bbl, royalties are one-sixth, and taxes are 5 percent, lifting costs must be less than $ (15 - 15/6) * .95, or $11.88/bbl for the well to remain profitable to operate.

According to the "standard reference" for lifting costs—the Joint Association Survey[19]-average lifting costs for oil and gas in the United States have been well below "per barrel" oil prices, even with taxes and royalties factored in. Average U.S. lifting costs were between 60 and 70 cents per barrel between 1959 and 1970, and did not rise above $2 per barrel until 1980. The 1982 **Annual Survey of Oil and Gas** shows 1982 lifting costs (without taxes) for oil and gas to be about $3.40 per barrel of oil equivalent (BOE), with average costs for Alaska at $0.97/BOE,[20] the Lower 48 onshore at $4.03/BOE, and the offshore at $2.81/BOE. Lifting costs for oil alone should be a bit higher because operating costs are generally higher for oil wells than for gas wells. The averages conceal a wide range, especially for the Lower 48; for onshore production, wells with high water production or in high cost secondary and tertiary recovery operations may have lifting costs exceeding $15/bbl, whereas certain high output wells may produce oil at less than $1/bbl.

Estimates of U.S. lifting costs at values considerably higher than the values reported in the Joint Association Survey have been reported in the media and elsewhere. The reasons for the discrepancies are not clear, although they may include definitional problems (the estimates may include excise taxes, although these are unlikely to add much more than $1.00/bbl to the total, or may refer only to higher cost wells without specifying that this is so). Some examples of higher reported lifting costs are:

- "Average United States lifting costs, including taxes" reported to be just above $10/bbl for the oil and gas system as a whole, in testimony of Dr. Alan Greenspan, President, Townsend-Greenspan & Co., Inc.
- The lifting cost of bringing oil to the surface is reported as varying from $7 to $15/bbl at onshore wells by R. Stanfield in National *Journal, 3/29/86.*
- Operating costs (including royalties and severance taxes) for different U.S. regions are presented as: Texas, $4 to $8/bbl except strippers, Gulf of Mexico $8 to $10/bbl, Arctic North Slope $14 to 24/bbl, in N. Barakat and S.M. Chronowitz, "Crude Oil: Nearing and Equilibrium, " Smith Barney Financial Services, Futures Special Report, Vol. 8 No. 5, spring 1986.
- Average lifting costs in sample lower 48 fields estimated as $6.80/bbl, in J. L. Copeland, Presentation to the Keystone Energy Futures Project on United States Liquid Fuel Policy, July 14, 1986, Copeland, Wickersham, Wiley & Co., Inc.

In general, OTA is skeptical of estimates of lifting costs well above those of the Joint Association Survey. However, the Copeland, Wickersham, Wiley, & Co. estimates were derived from a field-by-field survey of production costs and cannot be dismissed so lightly.

To what extent might lifting costs decline further in response to low oil prices?

Operating costs for specific categories of wells have begun to trend slightly downward during the past few years as a result of reductions in energy costs and some reductions in the costs of services and equipment for well maintenance. In particular, costs for fuel have declined in parallel with oil prices; this is an important cost component for enhanced oil recovery projects, but generally is less important for ordinary production because pumping energy often is electric and electricity costs have not fallen significantly. In general, the very substantial cost reductions seen in drilling services have not been matched by similar reductions in operating costs, nor are they likely to be. The drilling cost reductions have been driven primarily by the very large decreases in demand for these services; for example, the

[18] Some analysts choose to ignore taxes and royalties because these are viewed as negotiable; they believe these will be reduced sharply by their collectors if the alternative is a massive shutdown of drilling and production. For example, see the writings of M. Adelman dnd A. Tussing. Thus tar, there is little indication that major reductions in royalties and taxes are taking place.

[19] Joint Association Survey, America n petroleum Institute.

[20] Lifting costs for Alaska are low because the high transportation costs to bring this 011 to market have precluded the development of resources with high lifting costs.

number of operating rigs has declined from over 4,000 in 1981 to about 700 in 1986. The number of wells, on the other hand, will not decline drastically, and may even increase, so maintenance services will not have to face the enormous idle capacity faced by the drilling service industry. However, many well operators will defer maintenance, lessening the overall demand for these services, and certain categories of services—e.g., workovers for offshore wells—will face competition from equipment formerly devoted to drilling new wells. Other costs–e.g., electricity costs—may face downward pressure from State governments concerned about the potential for well closings. For example, the Oklahoma Corporation Commission has asked Oklahoma electric utilities to lower rates for well operations. Therefore, operating costs seem likely to remain stable or perhaps decline slightly in the near future, assuming oil prices stay low.

In addition to some moderate reductions in technical operating costs, there is some potential for reductions in royalties and taxes. In general, most royalty reductions are likely to be concentrated on new operations where operators can take advantage of the dropoff in competition for new properties to pressure property owners for concessions. There is less potential for royalty reductions with properties that have already been leased. For them, the property owners may be particularly reluctant to accept a lower royalty rate because their royalties have already been slashed because of the lower oil prices. Also, further development of producing properties will often remain quite attractive even at low oil prices because the major capital expenditures have already been made, so there will be less economic pressure on the owners of such properties to grant royalty concessions. However, on the most marginal properties, those most likely to be shut in, some property owners may be faced with the choice of accepting a lower royalty rate or losing their royalties entirely as the production shuts down.

The potential for lower tax rates is uncertain. The primary oil-producing States face a considerable dilemma in assessing tax strategy for oil production. A major portion of their operating revenues are derived from taxes on oil production, and the substantial dropoff in collections associated with the price drop has caused considerable budgetary problems. Reductions in tax rates probably would save some wells from shutting down. Given the low average lifting costs for oil wells, however, it seems likely that any reduction would lead to a further significant drop in State revenues, because the revenues "saved" because of the few wells prevented from shutting in would be overwhelmed by revenue losses associated with wells that would have continued to produce without a tax break. However, each shut-in well costs the State jobs, reduced taxes associated with employment, and costs associated with added needs for social services.

From the above, OTA concludes that pressures for reductions in lifting costs from existing wells are likely to continue to drive down average U.S. lifting costs, although only to a moderate extent. In addition, new drilling in a low price environment may tend to avoid areas and geologic situations known to yield high operating costs, even though operating costs are not the primary factor considered in drilling decisions; this would tend to hold down the average lifting costs of new wells. Finally, the wells being shut in and thus removed from the U.S. inventory of producing wells are those with the highest costs. Thus, OTA expects the U.S. average lifting cost to decline in the coming years if oil prices remain low, although most of this decline will result from a shift in the distribution of physical characteristics in the U.S. inventory of wells rather than from a substantial lowering of costs for particular services and types of wells.

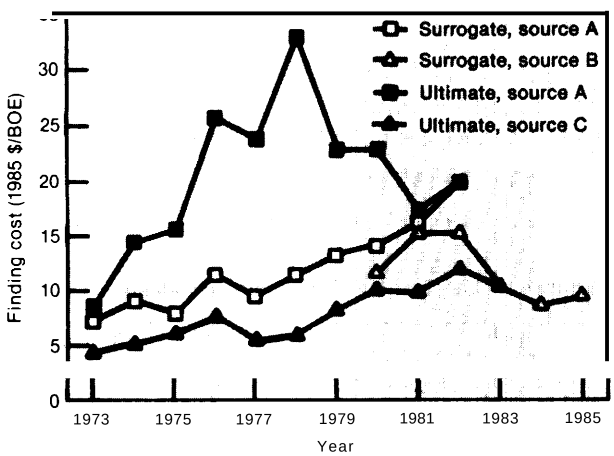
"Finding" Costs.– Finding costs are the full range of costs—including the cost of lease acquisition, seismic surveying, exploratory drilling, reservoir modeling, and development drilling—needed to bring oil and gas reserves to the point where they can be produced.

As explained above, decisions to drill new wells or otherwise develop new production depend on expected finding costs, or on components of these costs, depending on the stage of development the proposed activity is in. For example, the decision to buy a lease and drill new field wildcats should consider every component of finding costs as well as expected lifting costs if oil and gas are discovered. The decision to drill a development well should consider only the components of finding cost beginning with the cost of planning that particular well, since all previous costs have been sunk and cannot be retrieved.

Finding costs have undergone a major cycling, through boom and bust, during the past decade. For example, figure 6 illustrates the changes in finding costs over the past decade and a half, first during the drilling surge that followed the 1972 embargo and then during the decline accompanying the oil price declines that began in 1981. The major factors affecting these costs include:

- **The hyperinflation associated with the rapid increases in demand for drilling services, land, and other factors of production.** The inflation was caused by a growing inefficiency in providing drilling services and the greater "economic rent" collected by providers of these services . . . and the turnaround in costs was caused by the overall drop in oilfield activity. Similarly, the costs of the other "factors of production" —including land and seismic analysis—rose with the drilling boom and have deflated with the slide in drilling activity.
- **Changes in drilling targets,** with operators expanding their drilling efforts towards marginal targets and targets in difficult-and high cost—environments during the period of rising oil prices (driving finding costs up), then adjusting during the price slide by withdrawing from higher cost targets and focusing primarily on targets in less difficult environments with lower finding costs. Some of the movement towards marginal targets, however, reflected not economics but resource depletion, that is, a declining **availability** of low-cost opportunities.
- **Technological improvements** in drilling, seismic surveying, and other components of exploration and development.

Figure 6.—Oil and Gas "Finding Costs"
(costs for exploration and development)



NOTES
1 "Surrogate finding costs" match reserves booked in a year to expenditures made in that same year, even though actual costs to find and develop reserves are spread out over a number of years "Ultimate finding costs" attempt to match exploration and development costs to reserves by assuming typical lag times and levels of field growth.

2 The conversion to 1985 dollars was based on the GNP price deflator

SOURCES
A—L T Byrd, (The Keplinger Companies) and D.L. Moore (Arther Anderson & Co), "U S Oil and Gas Finding and Development Costs, 1973-1982, Lower 48 Onshore and Off shore," Sept 18, 1984 For lower 48 States.

B—Arther Andersen & Co., *Oil and Gas Reserve Disclosures, 1980-1983* and *Oil arrd Gas Reserve Disc/osures,* 1981-1985. For entire United States

C—A T Guernsey, ***Profitability** Study, Crude **Oil** and **Natural** Gas **Exploration, Development** and **Production Activities** in the USA 7959-1983,* report to Shell 011 Co , June 1985 For lower 48 States

There currently is no consensus on how finding costs will vary in the future. Although many analysts expected finding costs to continue a downward trend, established in late 1982, into 1985, the 1985 finding costs appear to have trended upwards.[21] In all probability, a substantial part of any future changes will be the result of changes in drilling patterns, as these patterns continue to adjust to the new economic conditions caused by the lower oil prices. Effects of technological change are difficult to predict because lower research budgets would tend to slow change whereas the radically new price environment might act to spur it on.

There also is no consensus on how the basic costs of services and other factors of production will behave in the future, although changes in these costs were a primary driver of past changes in finding costs. Right now, certain of these costs—especially drilling costs—are so low that the providers of the services are barely surviving,

21 According to the Arthur Andersen & Co. *Oil and Gas* **Reserve** *Disclosures, 1981-1985, 1985* finding costs per barrel were $11.85 (without revisions) and $9.39 (with revisions) compared to $9.94 and $8.29 in 1984.

deferring equipment maintenance and actually losing money in many operations.[22] For these services, any tightening of supply will surely lead to price increases, but the extent of such increases and their timing is not readily predictable (certainly, the overhanging surplus of equipment will limit cost increases in the near term). For factors that need not involve risk or investment on the provider's part—such as lease acquisition—it seems more likely that costs can remain extremely low until there is a substantial recovery of drilling activity.

Capital Availability and the Permanence of Capital Flight

Many industry analysts point to a shortage of capital to finance investments in exploration and development as a major factor in the severe depression that is rocking the upstream sectors of the oil industry, especially the independent producers. The severity and duration of this capital shortage would appear to be a critical determinant of future U.S. oil reserve additions and production.

During the late 1970s and early 1980s massive amounts of capital flowed into the oil industry as oil prices and corporate revenues soared amid expectations of even higher world oil prices. Between 1978 and 1985 over $300 billion was invested in petroleum exploration and development (see table 26). Annual expenditures peaked at $57.7 billion in 1981 and then declined to $33 billion in 1985. In the wake of the 1985-86 price drop, industry spending on E&D dropped sharply to half the 1985 level.[23] As can be seen from table 26, much of the increased E&P spending up to the early 1980s came from the independent sector.

The original wave of investment in exploration was funded from several sources: from rapidly expanding internal cash flows generated by higher oil prices; from private investors seeking high returns on publicly traded stocks and bonds or tax sheltered investments in oil and gas drilling funds, partnerships and trusts; from conventional bank loans secured by equipment or reserves; and from private placements by banks, other financial institutions, and large investors. Table 27 shows the sources of funds for the Chase Manhattan Group of large oil companies. Similar aggregate information is not available for independents.

Since the 1981 peak in the exploration boom, several trends have combined to limit internal and external capital availability for new exploration:

[22] For example, certain types of drilling services can now be obtained at less than the cash cost of providing these services. The providers are willing to accept the loss because the cost of mothballing their rigs is greater than the net cost to them of drilling.

[23] *Oil and Gas Journal,* Feb. 23, 1987.

Table 26.—U.S. Exploration and Development Outlays for 1973 to 1985 (billions of dollars)

	Larger firms[a]			Independents[b]			Total	
Year	$ Billions	% Change	% Total	$ Billions	% Change	% Total	$ Billions	% Change
1973	5.3	25	65	2.9	27	35	8.1	26
1974	8.6	62	69	3.8	33	31	12.4	52
1975	6.4	–25	62	3.4	–10	33	10.3	–17
1976	8.6	36	60	5.7	66	39	14.5	42
1977	10.3	19	62	6.2	9	38	16.5	14
1978	11.3	9	58	8.0	30	42	19.3	17
1979	15.0	33	56	11.8	46	44	26.8	39
1980	20.6	37	57	15.6	33	43	36.2	35
1981	29.8	45	53	26.7	71	47	56.5	56
1982	30.0	1	54	25.4	–5	46	55.4	–2
1983	22.7	–25	55	18.2	–28	45	40.9	–26
1984	22.1	–3	53	19.4	6	47	41.5	1
1985	NA	NA	NA	NA	NA	NA	33.0	–20

Exploration and Development Outlays include both capital expenditures and and exploration expenses excluding that portion associated with proven property acquisition.

[a] "Larger firms" includes most of the major oil companies in the Chase Manhattan Bank Group plus several other large domestic independents. Figures are drawn from the annual publication by the Chase Manhattan Bank, "Financial Analysis of a Group of Petroleum Companies" and adjusted for the additional companies.

[b] "Independents" includes all other oil and gas exploration and production companies. Figures are derived by subtracting expenditures by larger firms from total industry expenditures.

NA = not available.

SOURCE: Independent Petroleum Association of America, "United States Petroleum Statistics—19Bf3° (final).

Table 27.—Sources and Uses of Working Capital of a Group of Petroleum Companies (million dollars)

Year	Funds available from: Cash earnings	Long term debt issued	Stock issued[a]	Other[b]	Total	Funds used for: Capital expenditures	Dividends	Long term debt repaid	Other[c]	Total	Internal funds	External funds	Total funds
1975	22,714	10,129	a	1,217	*34,060*	*24,205*	4,819	5,316	1,740	*36,080*	23,931	10,129	34,060
1976	25,828	10,310	a	2,426	*38,564*	*26,036*	5,208	5,230	829	*37,303*	28,254	10,310	38,564
1977	29,003	8,678	a	4,424	*42,105*	*27,156*	5,995	5,954	1,508	*40,613*	33,427	8,678	42,105
1978	33,184	4,930	a	5,226	*43,340*	*28,770*	6,781	6,885	1,562	*43,998*	38,410	4,930	43,340
1979	55,844	8,568	a	6,984	*71,396*	*42,229*	8,127	8,249	2,473	*61,078*	62,828	8,568	71,396
1980	66,859	11,900	a	5,862	*82,821*	*53,776*	10,305	9,728	2,613	*76,422*	70,721	11,900	82,621
1981	63,207	16,585	a	1,723	*81,515*	*63,976*	11,068	10,020	4,867	*89,931*	64,930	16,585	81,515
1982	60,884	14,980	450	6,283	*82,597*	*64,538*	11,265	9,281	3,731	*90,019*	67,167	15,430	82,597
1983	60,256	8,704	300	6,706	*75,669*	*49,521*	11,057	7,524	4,507	*72,609*	66,962	8,707	75,669
1984	53,549	22,168	179	–4,738	*71,158*	*43,182*	10,297	8,280	21,671	*83,430*	48,811	22,347	71,158
1985 (est.)	63,600	19,100	500	14.200	*97,400*	*47.900*	12,600	22.600	19,500	*102.600*	77.800	19.600	97.400

[a]Included in Long Term Debt Issued.
[b]Other includes sales of assets and other transactions
[c]Other includes investments and advancements and preferred and common stock retired
a Included in Long Term Debt Issued

SOURCE. The Chase Manhattan Bank, Financial Analysis of a Group of Petroleum Companies

- The windfall profits tax cut sharply into the majors' earnings from oil production at prices over $20/bbl, removing an additional source of funds that might have been available for exploration and production (E&P) spending and perhaps deterring additional investments. (Countering the effects of the WPT, however, were tax incentives such as the investment tax credit.)
- Lower wellhead oil and gas prices meant lower revenues and earnings for many of the independent producers, who carried a lower WPT burden, and thus reduced internal cash flows that could be available for exploration.
- Federal income tax law changes in 1982 diminished the attractiveness of oil and gas tax shelters for private investors at the same time as the overall rate of return on oil industry investments began to decline in relation to the rate for manufacturing industries.
- The price-related decline in the value of oil and gas reserves and drilling equipment also reduced the value of assets that could be used as CO l lateral for bank loans.[24]
- The high debt levels incurred by many independents to fund the boom in exploration in 1979 to 1981 began to take an increasing share of available cash flow as prices fell and cut into discretionary capital spending.
- Similarly, the increased debt levels incurred by restructuring strategies (see section on "The Restructuring of the U.S. Oil Industry") absorbed a significant share of cash flow.
- A number of regional banks in the Southwest which had heavily financed E&P spending came u rider pressure from the simultaneous poor performance of loans to the oil and gas drilling services and equipment sectors and the agriculture and real estate sectors. With a rise in problem loans, many of these banks were less willing to lend their available funds for risky drilling ventures.

[24]Banks were commonly using a rule of thumb that required posting of collateral that had at least twice the value of the secured loans under several price scenarios. Oil prices have fallen as much as 60 percent in 1986. Moreover, some analysts believe that proven 011 reserves have declined in average price from $9 to $5 per barrel as of late 1986 and the value of loans that they could be used to secure has gone down correspondingly.

Even as the amount of capital available was constrained by these trends, disappointing exploration results and a decline in both oil and natural gas prices deterred investments of available funds in many high risk plays by oil companies and private investors. Exploration no longer enjoyed a privileged status among the major integrated oil companies and larger independents, as management weighed various options for enhancing shareholder values, and some opted instead to use available internal and external funds to pursue acquisitions, share buy backs, and other investments.

The sharp drop in oil production revenues and earnings that followed the 1985-86 price drop drastically increased the entire industry's capital availability problems by dramatically reducing the cash flow available to fund exploration and capital investment. The decline in capital availability has affected sectors of the industry differently, however, with the drilling and service companies and the smaller independent producers suffering the most. The high debt loads incurred by these companies, which funded much of the boom, placed them at greater risk during the initial price decline and the 50 percent fall in drilling activity between 1981 and 1985. By 1985, many of these firms were under financial stress, some were forced into default and were liquidated, and some sought protection under the bankruptcy laws. Of the remaining operators, many saw their financial condition weakened as a higher share of their cash flows went to debt service and the value of assets that could be used as collateral plunged. This reduction in collateral values also caused some loans to go into technical default, even though operators remain able to meet scheduled payments. As noted above, the regional banks which had financed their efforts were also u rider pressure from poor performance in the agriculture and real estate sectors, and were less likely to lend their available funds for risky drilling ventures. Although there are no reliable sources of information on private financing, which is a major source of funds for independent operators, many industry analysts believe that availability of private funds has declined because of current conditions in the industry and uncertainties over the implementation of the 1986 tax law. With fewer willing investors, companies may have to offer better terms to acquire funds, and combined with uncertain oil prices, this provides a strong incentive to avoid the high risk exploration ventures that often represent the best opportunities for reserve replacement.

Also hard hit were larger companies that were highly leveraged due to corporate acquisitions or anti-takeover strategies. These firms cut E&P spending first in 1985, with only a modest decline in world oil prices. They took even larger cuts in 1986 as cash flow was diverted to meet or reduce debt obligations and to maintain key financial indicators. These companies have less flexibility in the use of their available cash, and their ability to borrow further may be impaired by the high level of existing debt and uncertainty over future revenues. Perhaps because of this concern, several of these highly leveraged companies have devoted substantial efforts to reduce their high debt levels and/or to refinance the debt at more attractive interest rates.

In general, however, the larger companies—and especially those companies that did not incur sizable debt loads during the boom years—do not appear to have suffered nearly as much from capital availability problems. In particular, the integrated companies' downstream earnings helped to cushion some of their upstream losses as refinery margins increased and demand for gasoline and residual fuel oil increased. For example, as table 27 shows, total funds available from internal and external sources declined by only about $11 billion in 1982 to 1984, while capital spending (excluding acquisitions) dropped over $20 billion. Rather than a capital shortage, there appears to have been a deliberate shift away from E&P spending towards other uses of capital, such as acquisitions and debt repayment. Statements in company annual reports and congressional testimony generally attribute the reduced capital spending to a lack of profitable opportunities and not a lack of funds from internal or external sources. Also, the 1985 annual and 1986 quarterly reports of many major integrated oil companies and larger independents continue to show new long-term debt, indicating that their access to financing has not been substantially impaired. In 1985 to 1986, the **use of** borrowed funds changed; with limited exceptions, these funds have been largely used to refinance existing obligations, to repurchase shares, and to acquire assets of other companies rather than to fund new oil and gas development.

Even with the most recent drop in revenues, large oil companies remain among the largest cash flow generators in the United States and the world. Table 28 shows changes in revenues and earnings for selected major U.S. oil companies for the first 9 months of 1986. Not all of the earnings losses in the exploration and production segments this year will translate into lower cash availability, as many companies took one-time paper writeoffs against earnings.

Even the problems of the independent sector must be evaluated carefully. According to **Energy Performance Review,** independent oil and gas producers and oil field service companies suffered sharp declines in revenues and earnings in 1986; a group of 126 independent producers posted losses of $1.8 billion for the first 9 months of 1986. However, more than 100 percent of year to date losses were attributable to noncash charges against income.[25] The size of the noncash charges indicates that many companies likely posted net gains on their continuing operations that were then reduced by noncash charges against earnings to reflect such things as writedowns in the values of reserves because of lower prices, and losses on the sale of operations.

The critical question for determining the future of industry investments in exploration and development is: To what extent is the current pattern of the domestic oil and gas industry a transitional phase, and to what extent is it essentially stable so long as prices do not rise?

Many industry observers believe that uncertainty over oil prices and the factors noted above virtually ensure that, in the short run, little outside capital will flow into oil exploration and development. In the longer run, however, the relative importance of these factors is less clear. Other industries have been able in the past to adjust

[25] "Rough Third Quarter for Energy Companies," *Energy Daily*, Dec. 8, 1986, p. 1,

Table 28.—Financial Performance of Selected Oil Companies, First 9 Months 1986 v. First 9 Months 1985

	Revenues		Net profits			Capital and exploration expenditures				
Company	Million $	85-86 % Change	1986 Million $	85-86 % Change	1985 Million $	1986 Million $	1985 Million $	% Change 85-86	% of net income 1986	% of net income 1985
* Exxon	57,470	–16	3,880	27	3,065	5,627	7,144	–21	145	233
• Mobil	37,233	–16	1,204	96	615	2,179	2,436	–11	181	396
• Chevron	21,685	–37	801	–15	946	2,019	2,914	31	252	308
• Texaco	24,800	–29	675	–27	926	1,601	2,005	–20	237	217
• Shell	12,841	–14	628	–37	998	2,131	2,636	–19	339	264
• Amoco	15,394	–28	582	–63	1,563	2,114	3,372	–37	363	216
• ARCO	11,368	–33	551	—	—	—	—	—	—	—
Conoco	7,495	–21	331	–27	—	—	—	—	—	—
• Sun	8,230	–23	315	179	—	—	—	—	—	—
• Phillips	7,642	–36	217	–33	—	—	—	—	—	—
Ashland	7,300	–11	209	42	147	281	290	–3	135	198
* Occidental	1,175	4	161	–75	643	687	749	–8	427	116
• Unocal	6,297	–28	127	–73	460	666	1,100	–40	526	239
Texas Oil & Gas	732	–39	38	–87	—	—	—	—	—	—
Louisiana Land & Exp	620	–29	25	–67	—	—	—	—	—	—
Murphy	1,048	–37	13	–79	—	—	—	—	—	—
Coastal	48	–9		–95	94	125	219	–43	2655	233
Marathon	6,100	–23	(1)	—	—	—	—	—	—	—
Pennzoil	1,414	–17	(1)	—	—	—	—	—	—	—
American Petrofina	1,493	–15	(30)	—	—	—	—	—	—	—
• Tenneco	10,930	–2	(42)	—	—	—	—	—	—	—
• Diamond Shamrock	1,951	–21	(73)	—	—	—	—	—	—	—
Amerada Hess	3,139	–45	(278)	—	105	184	427	–57	—	405
Kerr– McGee	1,946	–20	(301)	—	109	230	325	–298	—	298
* Standard	7,750	–24	(376)	—	1,079	1,380	2,115	–35	—	196
Total	270,805	–22	8,660	–28	10,751	19,224	25,731	–25	263	239
• OTA group total	224,766	–23	8,649	—	10,295	18,404	24,471	—	213	238

*OTA Group

SOURCE : Oil and Gas Journal

to economic shocks by writing off bad investments, selling capital stock to new investors who can make a profit because they are buying at bargain prices, restructuring to reduce costs, rethinking their investment strategies, and developing new technologies that can better deal with a changed business environment. For larger integrated companies and independents without sizable debt loads, bank loans and private financing appear to remain available. Even though these funds have been largely used to refinance existing obligations, to repurchase shares, and to acquire assets of other companies rather than to fund new exploration ventures, it is by no means certain that this spending pattern will continue.

It may be overly pessimistic to assume that the oil industry's level of investment in exploration and development will not improve without a rise in oils prices that will restore some of the profitability of prior investments and boost cash flows. In the long run, the level of investment in E&D may be determined primarily by the basic economics of exploration and development, as defined by the question: How much return on investment can be gained by an additional dollar of investment? If new investments in oil exploration and development appear profitable, companies may once again plow back more of their funds into those ventures, and either new sources of capital could appear or else the old sources could return.

However, a critical and highly uncertain issue, for which there are no readily apparent answers, is the amount of time it might take for investment capital to return. Given the rapidity of projected production declines, an uncertainty of a year or more in a recovery from the industry's capital flight translates into a substantial uncertainty in the amount of any actual production decline. Furthermore, it is probable that any initial injection of capital into the industry will tend to gravitate to the lowest-risk opportunities. For a time, these opportunities may be the purchase of reserves and producing properties.[26] Only after the inventory of available properties shrinks is capital likely to flow primarily to the exploration and development activities needed to revitalize the industry.

Premature Loss of Existing Production: Stripper Wells

There is widespread concern that low oil prices will force many of the Nation's "stripper" oil wells, wells averaging 10 barrels or less per day, to shut down, with many or most never to reopen, their reserves lost. This concern is magnified by the importance of stripper wells to the U.S. oil supply, Approximately 1.3 mmbd–14 percent of total domestic oil production—are produced by stripper wells. There are over 400,000 of these wells in operation, producing an average 2.8 barrels daily .17 U.S. oil reserves associated with stripper wells total about 4.5 billion barrels,[28] 16 percent of current U.S. reserves of 28.4 billion barrels .29

A large shutdown, were it to occur, would affect a few States disproportionately. Between them, Texas and Oklahoma have a bit over half the Nation's stripper well production. Adding stripper production from California and Kansas incorporates fully three-fourths of the Nation's stripper production .30

The concern about shutdowns stems from the wells' physical characteristics as well as from the State and Federal regulations that govern them. Many of the wells have high per barrel operating costs because their maintenance costs are spread over so few barrels of production and also because, in many areas, the well production includes a high proportion of water that must be pumped to the surface, separated from the oil, and properly disposed of. At low oil prices, revenues from oil sales may drop below operating costs for many wells. For other wells with small positive cash flows during ordinary operation, the onset of any extraordinary repair costs may signal an impending well closure. And even without closure, many operators are likely to delay needed repairs and thus forfeit the additional production rates these repairs would allow.

If the oil production from shut-in stripper wells could be restarted, there would be no impact on national security. in many cases, however, production shutdowns will be permanent. For example, for "water-drive" wells—wells where formation water pressure moves oil to the well bore —a prolonged production shutdown may ruin the well, i.e., renewed pumping would produce only water. For all stripper wells, the time period during which a well's production can be shut in is limited by State and Federal regulations to prevent contamination of groundwater aquifers penetrated by the wells. Prior to the current price drops, most State and Federal regulations limited shut-ins to 90 days, with requirements that the well either be returned to production or be permanently plugged (with a concrete seal) after that time. With current well-plugging techniques, reentering a well is said to be little different in cost from drilling a new well. For wells with particularly low production rates, it seems unlikely that production would ever be restarted, and plugging these wells would likely result in a permanent loss of the reserves associated with the wells. Because of the concerns about a widespread loss of both production and reserves, some States have lengthened their shut-in grace period to a year or more.[31]

There is little disagreement with the thesis that oil prices at levels near or below $15 per barrel will have a significant adverse effect on stripper well closure rates and U.S. oil production rates. Unfortunately, however, a general lack of data on stripper wells makes it quite difficult to estimate quantitatively just what the effect will be.

[26]The price of oil and gas reserves has plunged from about $9/BOE in the first quarter of 1984 to about $5/BOE in the third quarter of 1986. Source: Strevig & Associates, in *Business Week,* Dec. 1, 1986, p. 114.

[27]As of Dec. 31, 1984, from Interstate 011 Compact Commission and National Stripper Well Association, "National Stripper Well Survey, " Jan. 1, 1985.

[28]Ibid.

[29]As of Dec. 31, 1985, from Energy Information Administration, *Advance Summary of the U.S. Crude 011, Natural Gas, and Natural Gas Liquids Reserves 1985 Annual Report,* September 1986, DOE/EIA-0216(85)Ad\ance Summary.

[30]Interstate Oil Compact Commission, op. cit.

[31]Of the two States with the highest stripper production, Texas now allows 1 year and Oklahoma 2 years before a shut-in well must be plugged, The Department of the Interior also has lengthened its grace period to 1 year for wells on Federal leases. *Energy Daily,* July 21, 1986, and other dates.

Also, the severe dislocations caused by the sudden price drop have altered operating and other costs and may have affected the business strategies followed by the well operators.

Estimates of production losses generally assume that traditional operating costs and business practices still apply. These estimates will likely overestimate the effect of lower oil prices. The lower oil prices have been accompanied by small but significant reductions in day-to-day operating costs and large reductions in costs for major items such as well reworking. Operators are negotiating with their service companies for lower prices or switching to alternative services. They are cutting labor to the bone and deferring maintenance.[32] In some States, authorities are pressuring utilities to grant lower rates of service to well operators. For example, the Oklahoma Corporation Commission has ordered the State's utilities to develop lower electricity rates for oil wells, with reported rate reductions ranging up to *22* percent.[33] And, in the face of declining oil production and threats of extensive well closures, States may take ameliorative actions such as cutting taxes to prevent the loss of jobs and the other economic hardships that the closures would create.

Before the price drop, stripper well operators generally would abandon wells as soon as the incoming oil revenues could not cover cash costs. Unless fracturing or some other production enhancement treatment (most of which are expensive) could boost production, there was little likelihood that the well would be profitable again soon enough to justify continuing to operate it at a loss. In the current situation, however, many operators are likely to believe that there is a fairly high probability that prices will rise sufficiently quickly, and to high enough levels to justify continuing production for (currently) unprofitable wells. Indeed, many stripper well owners view their wells as a family inheritance, one that has provided the means to keep family farms or educate their children. These owners are especially unlikely to give up their wells in the face of what many see as a short-lived attempt by OPEC to eliminate its competitors, to be followed by an inevitable price hike.

OTA knows of two analyses of the potential stripper oil production lost to low oil prices. One widely quoted analysis was sponsored by the Interstate Oil Compact Commission and conducted by The RAM Group, Ltd. of Oklahoma City.[34] This study first computes the stripper well production at different oil prices in Oklahoma using data obtained for that State's wells, and assumes that other States will sustain the same percentage stripper well production loss at each price level as Oklahoma. The study also assumes that wells will shut down when cash flows become negative, that is, when operating expenses exceed oil revenues.[35]

The results of the study for the United States as a whole are shown in table 29. At a $15 oil price, the study predicts a first year production loss of 277,000 barrels per day (bbl/day), or 3 percent of U.S. production.

The general approach of this analysis seems reasonable given the limited data, although OTA believes that the focus on cash flow and the inability to account for still-continuing changes in operating costs will tend to lead to an overestimate of the likely production loss. Also, the pattern of results as shown in table 29 does not appear realistic. Taken together with the data problems, the problems with the trends shown in the published results may limit the usefulness of the results as the basis for policymaking. OTA's overall objections are explained in more detail in box B.

The second analysis was conducted by the Dallas Field Office of the Energy Information Administration as part of their short-term oil production forecasts.[36] In this analysis, EIA used data on oil, water, and gas production from Dwight's Energy Data, Inc. production tape and Dwight's

[32] Of course, deferring maintenance will cause production problems sooner or later,

[33] *Energy Daily*, July 21, 1986.

[34] Interstate Oil Compact Commission, "Impact of Decreasing Crude Oil Prices on Stripper Oil Wells, Production, and Reserves," The RAM Group, Ltd.

[35] William Talley, President, The RAM Group, Ltd., personal communication, 1986.

[36] Energy Information Administration, *Short-Term Energy Outlook July 1986, DOE/EIA-0202(86/3 Q),* August 1986, updated by letter of Apr. 7, 1987, John Wood, Dallas Field Office, EIA to Steve Plotkin, Office of Technology Assessment.

Table 29.—Effect of Falling Oil Prices on Stripper Wells*

Oil price ($/bbl)	Percentage of stripper wells abandoned	Number of stripper wells abandoned	Production lost first year (b/d)	Gross value of production lost first year (thousand $)	Total reserves lost (million bbl)
$10/bbl	40.8	184,547	638,046	2,328,869	2,610.880
$15/bbl	22.5	101,958	277,090	1,517,065	733.812
$18/bbl	15.6	70,370	175,746	1,154,654	278.490
$20/bbl	10.0	45,390	106,586	778,077	92.783
$23/bbl	5.0	22,446	49,756	408,618	16.862
$25/bbl	0.0	0	0	0.000	0.000

* Based on 452,543 stripper wells as of Jan. 1, 1985, and average production of 2.8 bbl/day.

SOURCE: Interstate Oil Compact Commission and Ram Group Ltd. , 1988, in Oil *and Gas Journal, Mar 3, 1986, page 38*

Petroleum Data System, and published well operating cost data[37] to construct a distribution of stripper wells according to their oil production (and, given an oil price, their revenues) and operating expenses, by State. The primary data problems were the unavailability of water production data (critical to determining well operating costs) for some States and the overaggregation of much of the production data, some of which was available only at the field level.

The EIA analysis estimates that first year production losses will be *148,000* bbl/day at an oil price of$15/bbl, with additional losses of 77,500 bbl/day a year or two in the future as more wells are abandoned when major expenditures become necessary, for a total loss of 225,000 bbl/day. At $18/bbl, first year losses are 85,000 bbl/day, with additional losses of 4,300 bbl/day later, yielding a total loss of 89,300 bbl/day. For the $15/bbl case, the major State losses occur in Texas (73,900 bbl/day total, or 18 percent of State stripper well production), California (46, 100 bbl/day, or 29 percent), Louisiana (15,400 bbl/day, or 57 percent), Oklahoma (1 3,400 bbl/day, or 5 percent), New Mexico (1 2,400 bbl/day, or 30 percent), and Kansas (6,200 bbl/day, or 5 percent).

Overall, the EIA estimates of first year stripper well losses are about half the IOCC/RAM estimates. However, although the difference between the two sets of estimates may appear great, in OTA's view the differences in the national total are not at all unusual given the lack of data.

[37] V.T. Funk and T.C. Anderson, Dallas Field Office, Energy Information Administration, *Costs and Indices for Domestic Oil and Gas Field Equipment* and Production Operations *1985*, DOE/EIA-0185(85), April 1986.

The EIA analysis' wide State-to-State differences among the fraction of total production that is abandoned is, however, quite different from the RAM analysis.

More recently, an IOCC survey of California, Kansas, New Mexico, North Dakota, Oklahoma, Texas, and Wyoming indicated that 110,000 wells in these States, with 307,000 bbl/day of oil production, were shut in during 1986, with 12 percent of the wells permanently abandoned. * These values do not break out the production lost solely because of low oil prices (each year, thousands of wells are abandoned even at high oil prices), and thus they are not strictly comparable to the projections above. However, most of the production loss is likely to be attributable to the price drop, and the survey appears to add credibility to the (higher) IOCC projections. However, the state-by-state breakdowns show a wide variation among the States in the percentage of production lost (range: 3.6 to 11.1 percent), contrary to the assumption of interstate uniformity in the IOCC analysis.

As noted above, warnings about impending reductions in stripper well production invariably include the prediction that the reserves associated with the abandoned wells will be lost, either forever or until oil prices reach $50 to $100 per barrel. This is undoubtedly true for older wells that have depleted a major share of their original recoverable oil, or for newer wells that have been fractured and have already passed through the initial production surge associated with fracturing, assuming the use of current well abandonment techniques and well drilling technology.

*Oil *and Gas Journal*, Apr. *27*, 1987, p. 24.

Box 8.—Potential Problems With the Interstate Oil Compact Commission/The RAM Group, Ltd. Estimate of Stripper Well Production Losses Due to Low Oil Prices

1. The significance of the consultant's assumption that the stripper wells in other States will respond identically to Oklahoma's is not known. This assumption was forced on the consultant by the available data. The Energy Information Administration analysis projects significant differences among the State-by-State responses.
2. The decision to base the analysis on cash flow appears likely to overestimate the first year production loss. Continuation of the low prices should eventually lead to a loss of this magnitude, however, assuming the remainder of the analysis is correct. Prior to the recent price drop, well shut-in decisions generally were made on the basis of cash flow, because a negative cash flow signaled a production drop below the profitable range. OTA believes that, in the current environment, many operators will be willing to continue production at a small loss for a few years—rather than abandon their investment—in the hope that oil prices will go back up to profitable levels.
3. Analyses of this kind do not take into account the actions taken by operators and governments to avoid well abandonments. Operators are cutting costs by bargaining with suppliers, cutting labor, and deferring routine maintenance. Governments can take such actions as cutting taxes and exerting pressure on regulated suppliers to the operators (e.g., electric utilities). However, OTA notes that many of our industry contacts do not believe that oilfield operating costs can be cut substantially.
4. Of more significance than the above potential problems, the estimated rates of production lost per well do not appear at all realistic. According to table 29, the average production lost per shut-in well increases markedly as a higher and higher percentage of all wells are lost (i.e., as prices drop lower and lower). At very small production losses, the average shut-in well had produced at a rate less than 80 percent of the U.S. average stripper well production. As prices drop, and as the lower prices force some of the better producers to shut in and the percentage of wells lost increases, the average production lost per shut-in well increases steadily, reaching 1.25 times the U.S. mean production rate at a 40 percent loss and apparently still accelerating upwards.

   A possible physical explanation for this pattern is that, with a small decline in prices, the first wells to be abandoned are those with very low production rates and high fixed costs. At still lower prices, a relatively large group of stripper wells with high production rates but high costs—most probably because the wells produce a lot of water—are abandoned. Abandonment of this group of wells will pull up the average production lost per shut-in well. Finally, at even lower prices, wells with low production rates and relatively low costs are shut in, pulling down the average production rate lost per abandoned well.

   This type of distribution of stripper wells is theoretically possible but appears unlikely. OTA believes it is more likely that, as prices drop to lower and lower levels, the average (lost) production of the wells being shut in will begin (with only a few wells shut in) considerably below the mean U.S. stripper production rate and gradually (as more and more wells are shut in) rise to the mean production rate, equaling it when all of the wells are abandoned. This distribution is based on the observation that, in general, the lowest producers will tend to have the highest per barrel production costs and thus tend to be shut in first. (There will, of course, be lots of individual exceptions to this, such as higher producing rate wells that also produce lots of water and thus have high per barrel operating costs. These seem unlikely to be able to pull the average (lost) production of the shut-in wells way over the mean, however.) Consequently, OTA has severe reservations about the shape of the production curve implied by table 29, and is skeptical about the validity of the analysis.*

However, much of the drilling during the recent boom was aimed at geologic targets that promised stripper-type production levels. This implies that, where a substantial level of depletion has not occurred, a return to the economic conditions of the late 1970s to early 1980s may allow recovery of the "lost" reserves through new drilling. in addition, previously there was no incentive to devise well plugging techniques that would allow a relatively inexpensive reentry into the well. If such techniques could be devised, or if advances in drilling technology substantially decreased drilling costs, stripper abandonment could be reversed more readily.

The Nature of the Resource Base

The nature of the oil exploration and development prospects available to the industry and, in particular, the distribution of high- and low-cost oil is a primary determinant of future supply, and a critical uncertainty. Future development prospects, for example, range from a variety of enhanced recovery operations, to infill drilling and extensions, to high cost development in the Arctic and deep offshore; exploration prospects similarly range from new pools in old fields, to large numbers of small onshore fields, to the search for giant fields in difficult frontier areas. There is substantial controversy about the number of viable prospects in each category, and thus a similar degree of controversy about the true replacement costs of oil and the likely supply response at any price.

There are three types of prospects that represent the critical sources of uncertainty in considering the ability of the remaining U.S. oil resource base to support continuing development and production, especially in a low price environment. These are:

- the range of conventional drilling prospects that create field growth,
- exploration for small fields. and
- exploration for large fields including frontier giants.

The Prospects for Continued High Levels of Field Growth

The basic argument that continuing low oil prices will devastate future U.S. oil production hinges on the conception of the U.S. oil resource base as a mature, high cost resource base. According to this concept, most of the United States' low-cost oil has been found and produced; increasingly, new production must come from oil finds in hostile, expensive frontier areas or from high technology, high cost enhanced oil recovery operations, and neither of these sources can be developed at world oil prices of $15/bbl.

The recent history of the oil industry's efforts to regenerate the United States' oil reserves implies that this conception of a high cost resource base may be somewhat misleading. It is true that the geographic and technological frontiers—complex enhanced oil recovery technologies, drilling in the deep waters of the Outer Continental Shelf, onshore drilling to depths well below 15,000 feet, and exploring and producing in the extreme conditions of the arctic–have captured the major publicity. However, the great majority of oil reserves added to the U.S. inventory during recent times has come from non-glamorous sources. Fully 70 percent of the total U.S. reserve additions during 1979 to 1984 came from drilling thousands and thousands of extension and infield wells in the United States' large inventory of discovered oilfields. If Alaska and the offshore are subtracted, extensions and infield drilling from previously discovered fields accounted for 76 percent of reserve additions during the last decade, up from 66 percent during the 1950s and 1960s.[38] The potential for continuing high rates of reserve growth in discovered oilfields at relatively low cost is one key to the future of U.S. domestic oil production in a low price environment.

When new fields are discovered, their reserves are "booked" according to the geologic information gained from the discovery well and other initial delineation wells. For most fields, the initial estimates of reserve volumes are associated

[38] W.L. Fisher and R.J, Finley, "Texas Still Has Big Resource *Base,*" *Oil and Gas* journal, June 2, 1986, pp. 57-69.

only with those wells drilled in the discovery year. Afterwards, as the field is developed, the reserve estimates change, and most often grow. Reserves grow as additional wells are drilled to delineate the field's outer boundaries (extension wells) or to find additional reservoirs associated with the field (new pool tests). If prices rise or more efficient recovery technologies are developed, areas of the field that were previously subeconomic will be developed with additional development wells. Further knowledge of the reservoirs gained by production histories may lead to revisions in the reserve estimates, or may indicate that the existing well spacing is not recovering all of the recoverable oil, leading to an infill drilling program that can add to total recovery and thus to reserves. Rising prices may change the "abandonment" point (when the well is shut in because operating expenses overwhelm revenues) of the existing wells, leading to further positive reserve revisions. In some cases, for example when the reservoir rock has low permeability, well stimulation techniques such as fracturing may allow increased recovery, further adding to reserves. Finally, the portion of the oil-in-place that would not normally flow to the wellbore might be recovered with enhanced oil recovery (EOR) techniques that loosen the oil's bonds to the rock by heating or chemical means or that drive the oil to the well using a fluid or gas.

How will U.S. fields grow in the future? The historical record of reserve additions suggests that older oilfields have "grown" by a factor of about 7 to 8 and gas fields by a factor of about 4 over the 60-year period from 1920 to 1979.[39] Thus, the potential for further reserves from field growth will depend on the extent to which these old fields will continue to grow, and the extent to which more recently discovered fields, and new fields, will duplicate the growth potential of the older fields.

The primary argument for a relatively high reserve growth in new fields and continuing growth in older fields is that the volumes of "mobile oil''—oil that can be recovered with conventional drilling and well stimulation techniques–have been consistently underestimated, and that large amounts of this oil can be recovered with more intensive drilling even in the Nation's most mature oil basins. Proponents of this view point to the 1978 USGS estimate, based on a statistical analysis of past field growth, of potential reserve growth in Texas. The estimated ultimate growth of 4 billion barrels has already been virtually achieved in the **8 years since the original estimate was made,[40] and growth is continuing at a steady pace.**

A high estimate of the volume of mobile oil in existing oilfields is based on the proposition that the so-called "macroscopic" heterogeneity of hydrocarbon reservoirs is "the least studied, the least known, and the most difficult of the . . . types of variations to define with precision,"[41] and is often ignored or severely underestimated. Macroscopic heterogeneity refers to changes in reservoir characteristics that can partially or wholly isolate significant volumes of the reservoir, extending a few acres a really or a few feet vertically, from the remainder of the reservoir. Isolated compartments or layers of this nature would be obvious targets for infill drilling and multiple-zone completions.

A recent study of the potential volumes of mobile oil **over and above that recoverable with normal field development suggests a "target" on the order of 80 billion barrels of mobile oil-in-place for the total United States, with** an unknown but possibly high fraction of that being economically recoverable.[42] Continued advancement of the state-of-the-art of reservoir modeling and engineering, it is hoped, will allow infill drilling and well stimulation programs to be undertaken with relatively low technical risk. Assuming that this is so, the potential profitability of investments aimed at recovering additional mobile oil will depend on the trade-off between drilling and stimulation cost, on the one hand,

[39] D. H. Root, "Estimation of Inferred Plus Indicated Reserves for the United States, " app. F in G. L. Dolton, et al *Estimates of the Undiscovered Recoverable Conventional Resources of Oil and Gas in the United States*, U.S. Geological Survey Circular 860, 1981.

[40] Lewin & Associates, Inc., *Reserve Growth and Future U. S. Oil Supplies*, prepared for U.S. Department of Energy, June 30, 1986.

[41] W.L. Fisher and W. E. Galloway, "Potential for Additional Oil Recovery in Texas, " Geological Circular 83-2, Bureau of Economic Geology, The University of Texas at Austin, 1983.

[42] Lewin & Associates, Inc., op. cit.

and the additional oil volumes recovered. The referenced study[43] gives some examples of infill projects that appear, on the basis of the reserves/ well recovered, to have some economic potential even at today's low oil prices if drilling costs can be sustained at current low levels. However, there is little guarantee that these examples are reflective of the actual resource potential; it is worth noting that the analysts primarily responsible for raising the issue of mobile oil are acutely pessimistic of the potential for continuing high rates of field growth at current low prices.[44]

To place this potential for field growth in further perspective, it is important to note that there is by no means a consensus that heterogeneities within known field boundaries will yield large quantities of additional oil. Controversy about the ability of infill drilling to add substantively to reserves—rather than just to speed production—has continued for years. In 1967, a massive study of 312 reservoirs by the American Petroleum Institute's Subcommittee on Recovery Efficiency could not determine a relationship between well spacing and ultimate recovery.[45] And a recent review in the *Journal of Petroleum Technology* reiterated that:

> A key question in the debate is: "What portion of the additional oil recovered by infill drilling results from accelerated production of old reserves and what portion results from increased reserves?" This relationship is hard to quantify, and assessments differ.[46]

OTA's past work supports an optimistic view of the potential for infill drilling to add significantly to recoverable oil reserves. In a previous study, OTA examined the question of infill drilling's ability to add substantially to domestic gas reserves.[47] As part of this examination, OTA conducted a series of interviews with persons familiar with infill drilling and reservoir analysis. OTA found a definite majority in favor of the view that infill drilling could add substantially to gas reserves, not only in fields that were widely known to be heterogeneous, but also in fields that were generally considered to have relatively homogeneous, blanket-type reservoirs. This majority favored the view that recent experience supported the view of oilfields as more heterogeneous than previously understood, that this led to a substantial potential for increasing ultimate recovery through carefully selected infill drilling, and that this experience applied to gasfields as well.

Aside from the technical argument about reservoir heterogeneity, many producers argue that the large amount of infill drilling conducted in the 1970s and early 1980s has used up most of the infill potential in the Nation's stock of older fields, or at least that portion of the potential that was economic at the earlier oil prices. Furthermore, these producers argue that today's "less favorable" drilling economics reduce the current infill potential still further. The investigations of infill potential have not as yet produced detailed evaluations of the distribution of drilling prospects that would allow an economic analysis. As implied by OTA's analyses of some limited drilling ventures, however, low risk drilling prospects may be less attractive to producers at prices of $14/bbl or so than were identical ventures a few years ago, but prices closer to $18 or $20/bbl could turn this around; lower drilling costs have lowered significantly the "minimum required price" for most prospects.

Pessimists about the role of future field growth also believe that **new** fields may have less ultimate growth potential beyond their first year reserve estimates than the older fields. For one thing, the size distribution of new fields is weighted more heavily towards the smaller end of the spectrum, both because the largest fields tended to be discovered first and because recent higher prices had allowed fields to be developed in a size range that would have been termed uneconomic in earlier times. Most analysts would expect field growth to be highest for large fields, because the first year's discovery and delineation wells will discover more of a small field's reserves

[43] Ibid.
[44] Fisher and Finley, op. cit.
[45] A. F. van Everdingen, letter to George Fumich, Department of Energy, January 1980.
[46] "Industry Weighs Infill Drilling and EOR in Planning To Maximize Ultimate Production," *Journal of Petroleum Technology*, November 1983.
[47] U.S. Congress, Office of Technology Assessment, Energy and Materials Program, *Staff Memorandum on the Effects of Decontrol on Old Gas Recovery*, February 1984.

than they will of a large field's reserves.[48] Also, the location of many recently discovered fields in the offshore or frontier areas far from established pipelines demanded better delineation of field size before the reserves could be booked and transportation systems developed.[49] Our improved seismic technology and understanding of reservoir behavior also would tend to yield better —and generally higher—initial reserve estimates for newly discovered fields.

Exploration for Smaller Fields

A second important resource issue concerns the extent to which smaller fields–many of which might have been considered "dry" under previous economic/technological conditions—could provide substantial reserve additions, and production, in the coming decades. This issue hinges on both the magnitude of resources contained in small fields and the economic viability of pursuing small fields as a major exploration target.

Historically, small fields have played a minor role in oil and gas development. Fully 80 percent of all discovered oil and gas resources were found in fields of at least 50 million barrels of oil equivalent, whereas 1 million BOE is considered the cutoff point for "significant" field size. The size distribution of discovered oil and gasfields is shown in figure 7. As shown in the figure, as one moves to smaller field sizes, the number of discovered fields increases steadily down to about AAPG Field Size D and then rapidly levels off. At least a portion of this "truncation, " or leveling off, of the field size distribution is undoubtedly due to past economics. Many small finds were too small to be economically developed and consequently were reported as dry holes rather than added to the historical record as a class D or E field. Also, explorers may have been quick to abandon the search for additional fields in a productive area when it appeared that most or all remaining finds would be small. Thus, it has been argued that a field size distribution of **all** fields, discovered and undiscovered, would look more like the dark bars in figure *8.* This distribution assumes that the progression of field sizes established by the discovered larger fields would continue for the smaller field sizes if economics did not intrude.

Arguments about the number of small fields that may be available for exploitation are necessarily speculative because they are based on extrapolation only; no petroleum basin has experienced the intensity of drilling that would be required to find the postulated number of small fields. Some past experience with field size distributions supports the general principal that at least part of the dropoff in the number of small fields is caused by economic rather than geologic forces, however. For example, USGS studies of field size distributions in the Gulf of Mexico, the Denver Basin, and the Permian Basin show that the "truncation point" of the distribution moves to larger field sizes when exploration and development costs are higher, which would be expected if the truncation were economically determined.[50] On the other hand, some analysts argue that certain types of petroleum basins—containing a significant portion of U.S. petroleum resources—show a dropoff in the number of discovered fields at a field size level that is too high to be explained by economics.[51]

If the most optimistic field size distribution postulated in figure 8 is correct, or largely correct, there may be a substantial oil and gas resource residing in small undiscovered fields. in many instances, these fields would be in producing areas with an existing pipeline and processing plant infrastructure, so development costs would be low. However, the small size of these fields implies that the costs of discovery will be

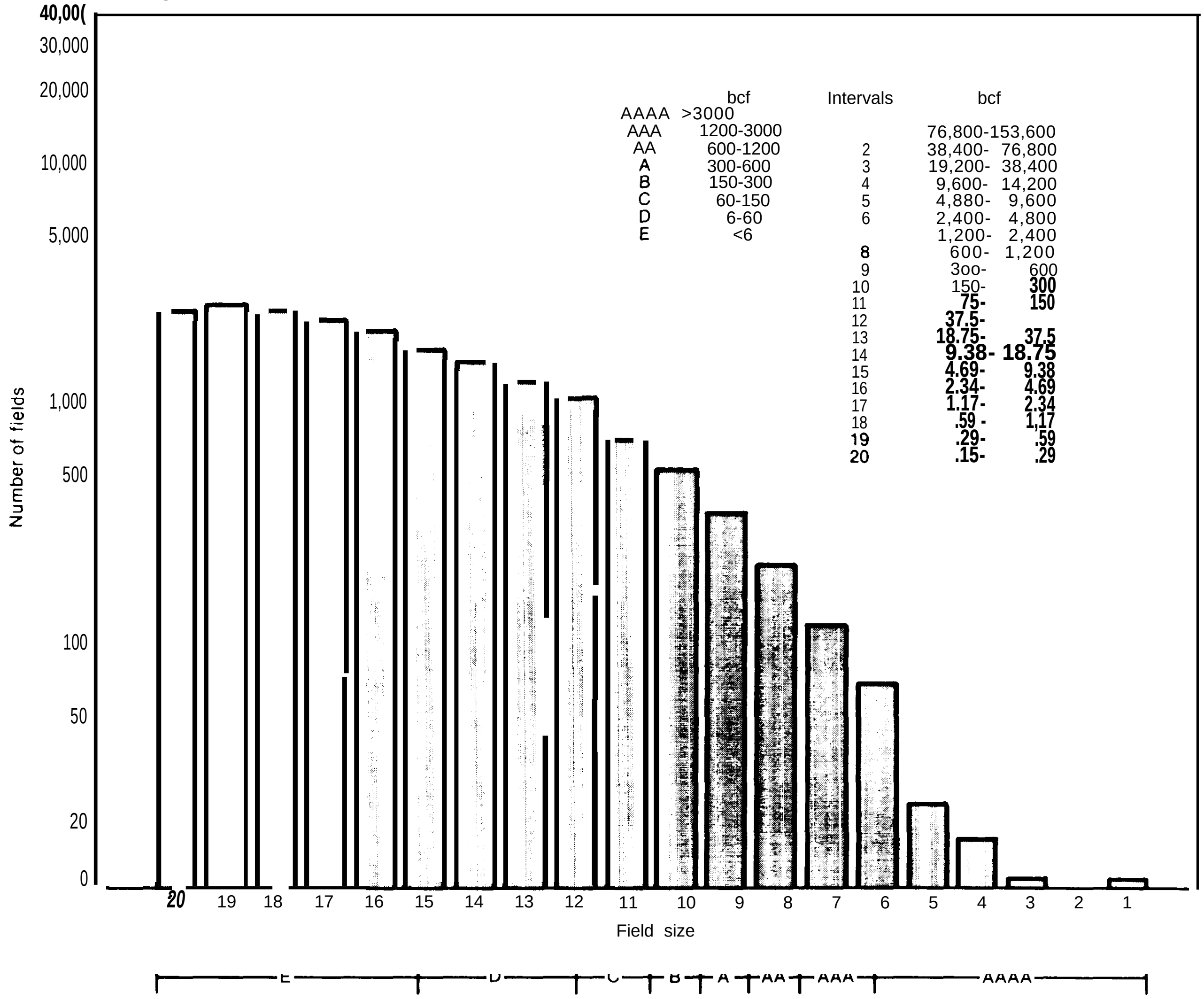
[48] One interesting though speculative counterweight to this argument is the observation that reserves found in small fields have more "boundary" than an equivalent magnitude of reserves in large fields (small volumes have a larger ratio of circumferential area to volume than large volumes), and thus may have more potential for extensions. Source: Charles Matthews, Senior Consultant, Shell Oil Co.

[49] However, the proportion of U.S. oil production from offshore areas has been relatively stable for the past two decades; the major period of growth was from the middle 1950s to the late 1960s. This somewhat weakens the lower field growth argument for oil. On the other hand, the proportion of offshore gas production has increased steadily from the 1950s to the present.

[50] J. H. Scheunemeyer and L.J. Drew, "A Procedure To Estimate the Parent Population of the Size of Oil and Gas Fields As Revealed by a Study of Economic Truncation, " *Mathematical Geology*, vol. 15, No. 1, 1983.

[51] R. Nehring, *The Discovery of Significant Oil and Gas Fields in the United* States, R-2654/l-USGS/DOE, RAND Corp., January 1981, pp. 78-94. Excursis, "The Distribution of Petroleum Resources by Field Size in the Geologic Provinces of the United States. "

Figure 7.—Size Distribution of Discovered Oil and Gas Fields in the Lower 48 States



SOURCE: R. Nehring. "Problems in Natural Gas Reserve, Drilling, and Discovery Data," contractor report to OTA, 1983

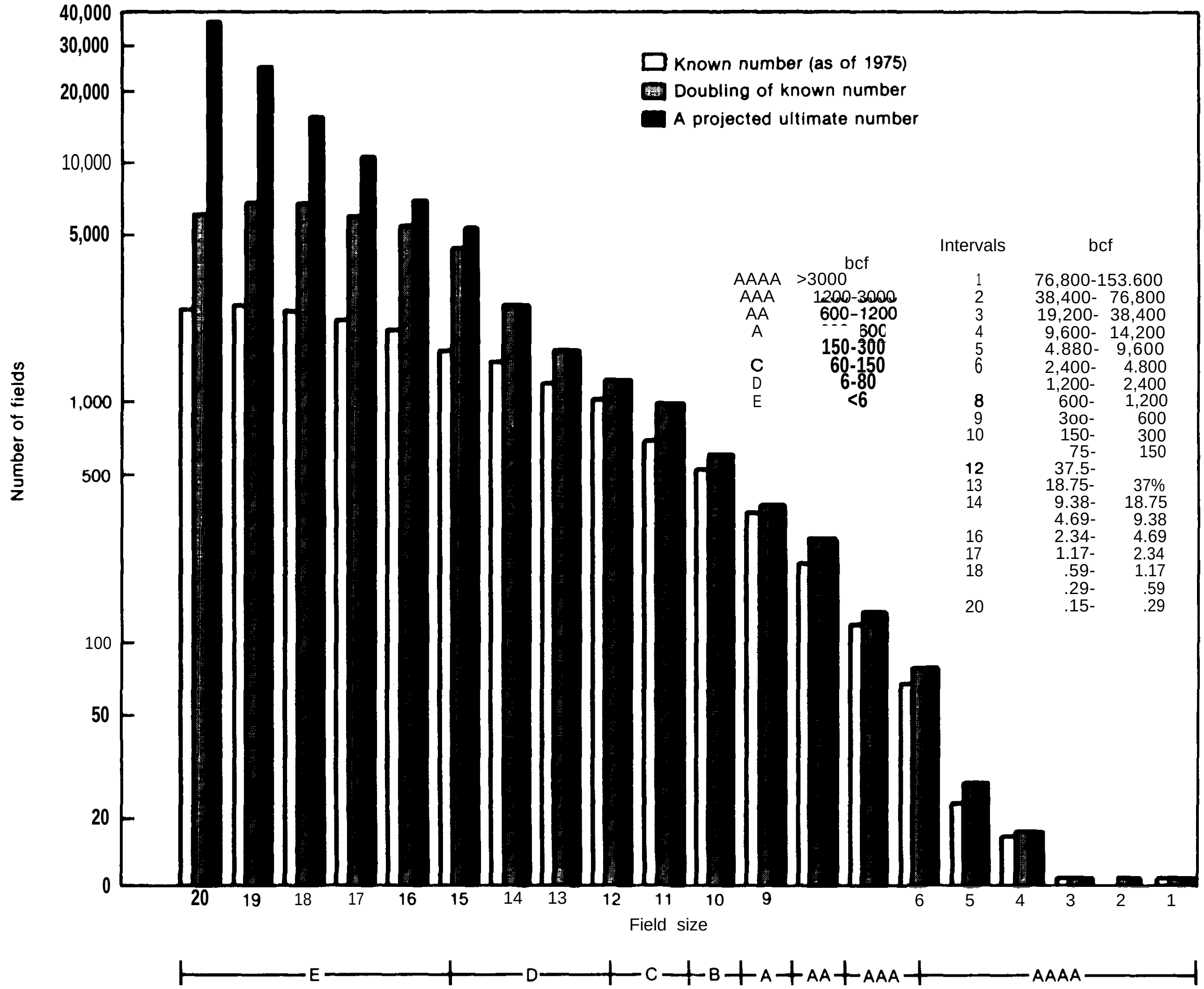
high, assuming historic ratios of dry holes to successful new field wildcats. Past studies of the economics of oil and gas recovery from the Permian Basin show that the number of exploration wells that will be drilled is extremely sensitive to oil prices, with as many as *38,000* exploration wells drilled at $40/BOE wellhead prices but only 5,000 drilled at a $10/BOE price.[52] Consequently, the possibility that substantial quantities of oil can be recovered from small fields at low oil prices depends primarily on the potential to lower the costs of discovering these fields by improving discovery technology and raising the success rate of exploratory drilling.

Finding New Large Fields

A third key to the continuation of high rates of reserve replenishment and the maintenance of long-term oil production is the extent to which U.S. oil explorers can continue to find large new fields at rates comparable to those of the past dec-

[52] U.S. Geological Survey, *Circular 828—Future Supply of Oil and Gas From the Permian Basin of West Texas and Southeastern New Mexico,* Interagency oil and Gas Supply Project, 1980, It should be noted, however, that the economic model used in this study does not capture the effect on drilling rates and resource economics of the dependency of drilling costs on 011 prices

Figure 8.—Known and Projected Size Distributions of Discovered Oil and Gas Fields in the Lower 48 States



SOURCE: Office of Technology Assessment, based on data from R. Nehring, "Problems in Natural Gas Reserve, Drilling, and Discovery Data," contractor report to OTA, 1983 ade and a half, and whether any of the few remaining prospects of extremely large size will be successful.

Since the early 1970s, the industry has discovered between *200* and 250 "significant" oil and gas fields (of size greater than 1 million BOE) every year.[53] In addition, the per well "finding rate" of exploratory drilling, which had been falling for decades, stabilized during the same time period and now appears to be relatively flat at about 470,000 BOE per exploratory well.[54] Nevertheless, this finding rate has not been sufficient to allow new field discoveries to play a really crucial role in reserve replacement during the past decade. For example, during 1979 to 1984 new field discoveries (with expected field growth) have added only about 2.4 billion barrels of reserves to the U.S. total, out of a total of approximately 15 billion barrels added during this period.[55] The reason for this is that very few of the new fields found have been the "giants" that played such a major role in the United States' emergence as an oil superpower. In recent years, the search for very large fields has been disappointing, with the well-publicized Mukluk dry hole being only one of a string of failures. Recent exploration efforts in the Gulf of Alaska, East Coast Jurassic Reef Play, Georges Bank, Beaufort Sea, St. Georges Basin, and the Norton and Navarin Basins have been either outright failures or have produced far fewer discoveries than anticipated, and recent assessments of U.S. recoverable petroleum resources are said to have severely downgraded prospects for frontier oil and gas. During the past decade, only six "one billion BOE''-size plays have been discovered–''the Barrow Arch oil and gas trend in Alaska, the Northwest Santa Barbara Channel oil trend in California, the overthrust Mesozoic oil and gas play in Utah and Wyoming, the Pliocene trend offshore Louisiana, and the Pleistocene Shelf and Slope trends offshore Louisiana and Texas."[56]

In the continuing search for large fields, the intersection of resource base issues and prospect economics comes into sharp focus. There still are sufficient geologic opportunities to continue the "baseline" discovery of 200 to 250 significant fields yearly **if the exploration effort aimed at finding** these fields holds up . . . but it is precisely in the area of exploration for new fields that industry analysts are most pessimistic about continuing the previous level-of-effort. Many companies are telling their stockholders that the focus of their reserve replacement efforts will be shifting away from exploration in the United States and towards field development. On the other hand, the "low oil price" run of the Gas Research Institute's Hydrocarbon Model, discussed elsewhere, indicated that, on a resource economics basis, exploratory drilling could hold up quite well. An accurate forecast of the level of exploratory drilling is critical to obtaining a credible forecast of reserve replacement and future U.S. production.

For the very most promising areas—those that appear to have real prospects for supergiant fields–arguments about current resource economics may be somewhat meaningless because the only remaining areas with such promise are in the deep offshore and Arctic regions, with time lags between leasing and production of a decade or more. It does not appear likely that the more aggressive majors would pass up opportunities to explore in these areas, because oil prices at the time of any production are unlikely to bear any relationship to today 's.

Two such prospective areas critical to longer term U.S. oil production potential are the unleased California offshore and the coastal plain of Alaska's Arctic National Wildlife Refuge (ANWR). Both these areas boast structures that could hold reserves of supergiant size, although the recent Mukluk disappointment should serve as a warning that there often is a long distance between potential and reality when it comes to petroleum

[53] R Nehring OTA Workshop on the Effects of Lower Oil prices on U.S. Oil Production, June 25-26, 1986.

[54] T. J. Woods and P.D. Holtberg, "Hydrocarbon Activity in an Era of Low Oil Prices," Society of Petroleum Geologists Paper 15355, 1986.

[55] Lewin & Associates, inc., *Reserve Growth and Future U.S. Oil Supplies,* op. cit., based on Energy Information Administration, U.S. *Crude Oil, Natural Gas and Natural Gas Liquids Reserves, 7984 Annual/ Report, DOE/E IA-021 6(84),* September 1985,

[56] Committee on U.S. Oil and Gas outlook, National petroleum Council, *Factors Affecting U.S. Oil and Gas Outlook,* draft final report, Nov. 3, 1986, quoted with permission.

resources. Both areas are extremely controversial leasing targets as well, California because of the remembrance of the Santa Barbara spill and a longstanding aversion among many of the State's residents to offshore development, and Alaska because of the wildlife and wilderness Issues.

Because the ANWR is considered by many geologists to represent the most prospective remaining frontier area in the United States, and because it is today embroiled in controversy, OTA thought it useful to discuss it here in greater detail.

The Arctic National Wildlife Refuge

ANWR was established in the extreme northeast corner of Alaska in 1960 as the Alaska National Wildlife Range. It is the part-time residence of approximately 180,000 caribou and millions of waterfowl and home to such species of animals as musk oxen, Dall sheep, wolves, arctic foxes, wolverines, brown bears, polar bears, and arctic ground squirrels and other rodents. Originally comprising 8.9 million acres, the Range was expanded in 1980 to 19 million acres (about half the size of the State of Washington) with the adoption of the Alaska National Interest Lands Conservation Act (ANILCA). In all, ANILCA added more than 106 million acres to Federal conservation systems in Alaska. ANWR was redesignated as a refuge at this time, and 8 million acres of it were added to the wilderness system. At the behest of Senator Stevens of Alaska, 1.5 million acres on the coastal plain, which were considered to have significant oil and gas potential, were set aside for further study. The area is known as the 1002 area, since Section 1002 of ANILCA required the Secretary of the Interior to prepare a report to Congress on the fish and wildlife resources and oil and gas potential of the area and to recommend whether further exploration, development, and production of oil and gas should be allowed. A draft of the study was released in December 1986, and the final report was delivered in April 1987.

Petroleum Resources

The western boundary of ANWR lies approximately 60 miles east of the giant Prudhoe Bay oilfield—the largest in the United States. Prudhoe Bay was discovered in 1968 and was estimated to contain over 10 billion barrels of recoverable oil. Once in full production, the field produced about 1.5 million barrels of oil daily —approximately 12 percent of the crude oil processed through U.S. refineries each day. The so-called 1002 area of ANWR, which is being considered for possible future mineral leasing, is located in the coastal plain as is Prudhoe Bay and shares many of the geological features of that highly productive field. For this reason it is believed that large recoverable oil and gas resources may also occur in ANWR.

All of the oil production from the Prudhoe Bay and the smaller adjacent Kuparuk River field is from sandstone rocks of the Ellesmerian sequence. At the time the Ellesmerian sequence was formed, conditions prevailed for the accumulation of potential petroleum-producing sediments which are believed to have later undergone transformation into hydrocarbons. The porous Ellesmerian sandstone is believed to have permitted the petroleum to migrate through the formation until intercepted and trapped by impervious, folded basement rocks. Geologists believe that the petroleum potential of the 1002 area will largely depend on the extent that the Ellesmerian sequence underlies the ANWR coastal plain.

Other parts of the 1002 area are underlain by the younger Brookian sandstone sequence which is producing oil in the Endicott oilfield offshore Prudhoe Bay and in the Point Thomson field near ANWR. A number of offshore wells in the Canadian portion of the Beaufort Sea north of Mackenzie Bay are also producing oil from Brookian rocks. Geologists expect fewer sealed traps to exist in areas underlain by the Brookian sequence, hence the prospect for large quantities of petroleum to exist in such areas is less than for the Ellesmerian sequence. Oil seeps on the coast near Kaktovic, Point Thomson, and Demarcation Point are additional evidence of oil potential in the 1002 area.

In preparing its Section 1002 resource report for Congress, the Department of the Interior collected seismic information over 1,300 miles of the ANWR coastal plain. Interpretation of the seismic data by the U.S. Geological Survey identified 26 potential hydrocarbon traps. Underground features or structures in the northwest quarter of the 1002 area appear to dip gently to the northeast with comparatively little deformation, in a manner similar to the Prudhoe Bay structures. The southeastern portion of the 1002 area is much more complex and contains many folded and faulted structures. Complex geology of this kind makes interpretation of the existing seismic data more difficult, but several very large structural closures that could contain oil have been identified. Similar overthrust structures in the Canadian and U.S. Rocky Mountains have produced significant amounts of oil and gas.

The 26 identified possible hydrocarbon traps are located in 7 plays (areas with similar geologic characteristics that share common geological elements). Resource estimates for the 1002 area are based on geologists' judgment about the geologic factors necessary for formation and retention of oil and gas and evaluation of the properties that could determine the size of a petroleum deposit. Based on such expert judgment, statistical analyses are used to determine probability estimates of possible in-place oil and gas resources. Finally, economic analyses are applied to the geological estimates to determine the volume of oil that could be removed from the deposit using current technology.

Because of the inexactness of resource estimates based largely on seismic data, geological analogies, and future cost-price assumptions, petroleum resource estimates such as those assigned to the 1002 area should be considered as "relative indicators" for comparison with other potential resource-rich areas rather than as absolute volumes of recoverable petroleum. A shift in assumed oil prices can significantly change the economics of the minimum field size, which in turn can increase or decrease estimates of recoverable oil. Changes in the geologic assessment can dramatically change the estimates of economically recoverable oil. In the final analysis, estimates of both in-place and recoverable oil and gas resources should be considered more "guesstimates" than scientific assessments. Exploratory drilling remains the only certain and totally objective way to determine the presence and extent of oil and gas resources.

it is clear that ANWR ranks high among the range of potential petroleum-producing prospects remaining in the United States either onshore or in the Outer Continental Shelf. Even though the resource potential for the 1002 area is considered to be great, however, USGS geologists give odds of only one in five (20 percent) that a commercial discovery will be made in the entire area should it be explored. This so-called "marginal probability" for discovering an economic deposit seems surprisingly low for an area with such favorable geological attributes and demonstrated oil production close by. However, the National Petroleum Reserve in Alaska (NPRA), which lies to the west of Prudhoe Bay about 50 miles in a similar coastal setting, has thus far failed to yield a commercially important oilfield after substantial drilling, although the U.S. Geological Survey estimated in 1979 that 7 billion barrels of oil in-place (not gauged by its recoverability) could be expected.

DOI's resource estimates for the 1002 area of ANWR are shown in table 30.

**Table 30.—Estimated Oil and Gas Resources in the Arctic National Wildlife Refuge Section 1002 Area (recoverable volumes based on oil price of $33/bbl,** 1984$)

	Oil (billion barrels)			Gas (trillion cubic feet)		
Type of estimate	95 "/0	Mean	5%	950/0	Mean	5%
In-place resources[a]	>4.8	>13.8	>29.4	>11.5	>31.3	>64.5
Conditional recoverable[b]	>0.6	>3.2	>9.2	—	—	—
Recoverable risked mean[c]	—	>0.6	—	—	—	—

[a]Total volume below the ground of which perhaps 25 to 35 percent may be recovered economically An estimate based wholly on geological factors
[b]Economically recoverable 011 that may be available if an economic deposit occurs The odds are one in five (20 Percent) that this will be the case
[c]The estimate of Conditionally Recoverable 011 reduced 80 percent to allow for the possibility that none may occur

SOURCE: U S Geological Survey

Undiscovered oil and gas estimates frequently result in confusion during debates over resource development on public lands. Petroleum geologists express oil and gas resource statistics in three different ways:

1. "In-Place" resources–the total volume of petroleum expected to occur without regard to economic recoverability or the chances that petroleum may not occur at all.
2. "Conditional, Economically Recoverable resources''—the volume of oil or gas that could be recovered under assumed economic conditions and levels of technology, ignoring the possibility that resources may not occur at all.
3 "Recoverable Risked Mean''–the conditional economically recoverable resource estimate adjusted downward by the probability that oil or gas may not occur in commercial quantities in the area.

Each type of estimate has its uses, but one must be careful about the interpretation lest he be misled. In-place resource estimates have not been subjected to the vagaries of economic and technological assumptions and predictions that determine how much of the oil in place can be economically recovered. Should oil actually be discovered in economic quantities in the ANWR 1002 area, in-place estimates can provide an insight to a field's ultimate potential as technologies or economics improve. This is important for long-range planning in anticipation that drilling and production technologies may improve or that energy prices may change in the future.

Conditional economically recoverable oil and gas estimates, on the other hand, provide information useful in determining the economic and strategic potential of a prospect based on existing or foreseen economic and technological trends. It provides a basis for evaluating the worst-case scenario for environmental and socioeconomic impacts that could result from development of the ANWR 1002 area should commercially important discoveries occur. The chance that commercial-scale deposits may not occur in the area is not a factor considered in the conditional estimate.

Risked mean economically recoverable oil and gas estimates factor in the possibility that no economically recoverable resources exist in the 1002 area. This reduces the conditional estimates of recoverable oil in proportion to the risk that no commercially recoverable oil exists in the area. In the case of ANWR, 3.2 billion barrels of economically recoverable **oil is reduced** by 80 percent (the probability that no commercial discoveries of oil will occur in the 1002 area) to determine the risked mean estimate of about 640 million barrels of oil. Natural gas was not considered currently economically recoverable, hence no estimates of gas were included in either the conditional and risked mean estimates, although a mean of 31 trillion cubic feet are estimated to occur in-place.

The risked mean resource estimate accounts for the realities of exploring for oil and gas in frontier regions where few exploratory or stratigraphic wells have been drilled. It is most useful for estimating regional and national oil and gas resources, where estimates of the potential resources in several unexplored areas must be combined, or for comparing areas. In the offshore frontier OCS areas, the marginal probability that oil might occur ranges from one percent in the Hope Basin to 70 percent in the Beaufort Sea off the north coast of Alaska. Why the marginal probability of oil in commercially recoverable volumes is 20 percent for the ANWR 1002 area and increases to 70 percent in the Beaufort Sea offshore area immediately north of ANWR, where even less is known about the subsurface geology, was not addressed in the U.S. Geological Survey's resource estimates of the 1002 area.

ANWR is one of the few remaining unexplored major onshore prospects in the United States. Although much of Alaska remains unexplored for oil and gas, ANWR holds the most promise for the discovery of giant fields. Most of the other highly prospective oil and gas areas are offshore in the Outer Continental Shelf. When risked mean resource estimates of oil for the ANWR 1002 area are compared with the frontier OCS oil and gas lease planning areas, it ranks third, behind the Navarin Basin (1.3 billion barrels), and the Beaufort Sea (0.9 billion barrels). Furthermore, when the results of recent drilling disappointments in the Navarin are formally factored into resource calculations, ANWR might rank still higher. Risked mean resource estimates for ANWR nearly match those expected for the entire Atlantic OCS Region (0.68 billion barrels).

Both the Navarin Basin (upper Bering Sea) and the Beaufort Sea, being in offshore Arctic waters, are located in difficult operating environments which must contend with sea ice, severe weather conditions, extremely low temperatures and long winter periods of near total darkness. Offshore exploration and development is extremely expensive under these conditions, and the distances that oil would have to be transported will likely require very high per-barrel prices (>$32 per barrel) and giant fields of 250 to 500 million barrels to warrant development. The Department of the Interior determined that the most likely minimum economic field size in ANWR would be 440 million barrels at $33/bbl (1 984$). This appears to be somewhat larger than might be expected when compared to more expensive offshore development. However, the determination of economic field size depends on many assumed economic factors, in addition to location onshore or offshore, which cannot be determined in frontier regions until a field is delineated.

ANWR Petroleum Resources in Perspective

The economics of any exploration and development of oil and gas resources that may occur in the ANWR 1002 area are closely tied to the existence of the Trans-Alaska Pipeline System (TAPS) which originates at Prudhoe Bay. TAPS has the capacity to transport about 2.2 mmbd of oil from the North Slope to its marine terminal at Valdez on the southern coast of Alaska. Prudhoe Bay throughput has ranged between 1.5 and 1.8 mmbd since the field came on line at maximum production. However, with Prudhoe Bay production soon to be declining and increases in oil reserves *through* field extension not keeping pace with drawdown, there will likely be ample excess pipeline capacity to accommodate as much as 1 mmbd of oil from ANWR by the time that maximum production could possibly occur,

While the cost of a feeder pipeline from ANWR to Pump Station No. 1 at Prudhoe Bay would be substantial, the existence of TAPS and its potential excess future capacity boosts the economic outlook for ANWR. However, the potential resource base is not equally distributed throughout the 1.5 million acres of the ANWR 1002 area. Over three-quarters of the in-place oil is expected to occur in the extreme western portions and the extreme eastern portions, with the central area having the lowest potential. Resources that may be discovered in the eastern blocks of ANWR would require almost double the length of feeder pipeline required for resources occurring in the western block.

Although natural gas was not considered by the Department of the Interior in determining the estimates of economically recoverable resources, its potential as a future resource cannot be wholly ignored. Prudhoe Bay gas is currently reinfected into the producing formations to maintain pressure and conserve the resource. Production in ANWR would follow a similar course. But the uncertainty of the U.S. energy future suggests that Alaskan natural gas may evolve into a future economic resource of considerable value. Although no credible analysis could be devised to prove this point, sufficient uncertainties about energy pricing and hydrocarbon supplies exist so that the possibility of future economic viability should not be discounted.

Current prices in the depressed world oil market logically raise questions about the feasibility of exploring for petroleum in the high-cost Arctic Tundra. But today's oil prices are not a reasonable measure of economic feasibility for investment in exploration and development that may require decades to complete. From the time the Secretary of the Interior forwarded the ANWR report to Congress (in April 1987), at least 3 to 5 years may be necessary for the enactment of leasing legislation. Unless Congress approved administrative shortcuts, at least an additional 3 to 4 years would be needed to promulgate regulations, prepare an environmental impact statement, and process leases.

If exploration and development were to begin between 1992 and 1995–6 to 9 years after the legislative process begins–it would not be until

2002 to 2005 that production would likely begin in ANWR assuming 10 years from the beginning of exploration to development and first production. Recent experience with erratic changes in energy prices and the course of the national economy suggests that it is foolhardy to speculate on economic conditions 15 to 18 years in the future.

Exploration costs in the coastal plain of ANWR would be considerably cheaper than any comparable offshore exploration program in the OCS with the highest prospects for the discovery of very large oilfields. The cost of drilling an exploratory well onshore in the Arctic is generally estimated to be in the range of about $10 to $25 million. An exploratory well in the frontier Navarin Basin in the Bering Sea is estimated to cost about $55 million. Exploratory wells in the Beaufort Sea are estimated to cost on the order of $30 million for ice-free conditions and up to about $50 million for ice conditions. The Mukluk exploration well on an artificial island in the Beaufort northwest of Prudhoe Bay, when abandoned as a dry hole, cost an estimated $140 million, although part of the high cost has been said to be due to the need to maintain a very fast pace.

The Department of the Interior foresees the **need for about** 25 exploratory wells for the ANWR 1002 area under its full leasing scenario and 16 under a scaled-down alternative centered on the best drilling prospects. If drilling costs can be held to the low side of the range for onshore Arctic drilling, total cost for exploratory drilling (not including general support facilities) on ANWR could range between $160 million and $250 million. Compared with the costs for drilling exploratory wells at single locations in the best offshore prospects of Alaska ($30 to $50 million and up, for most situations), ANWR may offer the cheapest and perhaps the most direct way to determine whether another giant oilfield lies below lands under the jurisdiction of the United States. However, before ANWR is leased and explored, formidable environmental issues must be resolved.

Environmental Issues

Background.–A major battle is expected between development-oriented and environmental groups over the issue of whether or not to proceed with oil and gas exploration and eventual development in ANWR. The oil industry, as well as many elected officials from the State of Alaska, key personnel from the U.S. Department of the Interior, and several native Alaskan organizations, view the coastal plain of the ANWR as having the most promising oil and gas potential of any region in the country. Environmental groups contend that the wilderness value and wildlife habitat the area provides are unparalleled and that development would threaten the animals (particularly the Porcupine caribou herd) that spend all or part of their time in the Refuge.

The Fish and Wildlife Service (FWS) was designated by the Department of the Interior to conduct the 1002 study on the fish and wildlife resources and petroleum potential of the ANWR coastal plain. The study is essentially a response to the question of whether or not oil and gas development can coexist with wilderness and wildlife in the ANWR area, or, alternatively, a determination of the relative importance with respect to national needs of oil development and preservation of the refuge. FWS found that "long-term losses of fish and wildlife resources, subsistence uses, and wilderness values would be inevitable consequences of a long-term commitment to oil and gas development, production, and transportation,"[57] and also that leasing of the 1002 area "could contribute billions of barrels of additional oil reserves toward the national need for domestic sources."[58] Based on its findings, FWS has recommended that Congress authorize the Secretary of the Interior to lease the entire 1002 area for oil and gas exploration and development.[59]

Key Environmental and Socioeconomic Concerns.–The entire ANWR, including the coastal plain, is in fact if not in name a wilderness area, that is, an area essentially untouched by development. Although the area considered for leasing (1.5 million acres) is only a fraction of the refuge, it includes virtually the entire coastal plain of northeast Alaska.

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[57] U.S. Department of the Interior, *Arctic National Wildlife Refuge, Alaska, Coastal Plain Resource Assessment* (Washington, DC: U.S. Department of the Interior, November 1986), p. 6.
[58] Ibid., p. 8.
[59] Ibid., p. 1.

Environmentalists argue that oil development in ANWR would not only diminish the wilderness nature of the coastal plain but would eventually make it easier to explore adjacent offshore areas and the remaining State land between Prudhoe Bay and the ANWR for oil and gas potential. All of these developments would have additional negative environmental impacts on the Arctic coastal plain. A bill to designate the coastal plain of the ANWR as wilderness has already been submitted to Congress by Congressman Morris Udall and was recently reintroduced in the 10Oth Congress.

A key concern is the impact that development will have on the approximately 180,000 caribou of the porcupine herd that use the refuge. One part of the coastal plain is particularly important as a calving area for the Porcupine herd. The coastal plain also offers relief to the herd from insects. Before actual exploration and development occurs, it is difficult to say what the impact of oil and gas development on the herd will be. Those in favor of development point out that the Central Arctic caribou herd, whose range includes the Prudhoe Bay area, has actually increased in size since development began. The Porcupine herd, however, spends less time on the coastal plain than the Central Arctic herd, and the question of whether the Porcupine herd can be acclimated to development like the Central Arctic herd is open to debate.

The U.S. Fish and Wildlife Service has concluded that it is reasonable to assume that development can proceed with minimal adverse impacts on the herd. In the draft 1002 report, FWS proposed that the most sensitive area (an area of approximately 242,000 acres) be leased last—after determining how the caribou respond and what mitigation measures would be most effective. The final version of the draft, however, recommended that the entire coastal plain be opened to leasing. Most environmental groups are not convinced that oil and gas development is compatible with the health of the caribou herd. Also, although the focus of attention has been on caribou, other wildlife in the area could be affected by development.

Of particular concern to some environmentalists is construction of a haul road and pipeline connecting Prudhoe Bay with the ANWR. The presence of either would disqualify the coastal plain for wilderness status. in addition, the pipeline could be a barrier to caribou migration, and some worry that it could eventually be extended to the MacKenzie Delta area in the Canadian Arctic,[60] thereby eliminating more wilderness.

Socioeconomic consequences for the native Inuit population (especially in the village of Kaktovik) are also expected to be significant. The Inuit have subsurface rights to a considerable amount of acreage and can be expected to profit from development. Two native corporations, the Kaktovik Inupiat Corp. and the Arctic Slope Regional Corp., are involved, and have generally been supportive of controlled development. Other native groups–particularly those dependent on the Porcupine herd but unlikely to share in the direct economic benefits of oil development—have opposed development.

Development would bring changes in the traditional subsistence lifestyle of most natives, as more Inuit would have the opportunity to work for cash in the oilfields. Introduction to 20th century culture has proven to be a two-edged sword to Inuit in other parts of the Arctic, however. Modern conveniences benefit Inuit just as they benefit others, but development is also at least partly responsible for the increase of such social problems as alcoholism. While happy to have additional income, many Inuit regret the decline of traditional culture.

The Effects of the Natural Gas Surplus

Since the early 1980s, natural gas production capacity has been in substantial surplus, primarily because of declining demand in the electric utility and heavy industry sectors but also because of a surge in gas deliverability. This surplus has been remarkably persistent, and it has created a situation in which producers in some parts of the country cannot be assured of markets for new gas production. The disincentive for gas drilling

[60] Although there appears to be little reason for such an extension, because the TAPS pipeline should have adequate excess capacity in the appropriate timeframe to handle any ANWR production.

created by poor markets has affected overall drilling patterns of the past few years. The overall economic effect on oil drilling is mixed: on the one hand, because many oil wells produce gas and because some drilling seeks hydrocarbons rather than oil or gas in particular, the slack gas market can hurt oil drilling; on the other hand, the reduction in total drilling caused by the poor gas market was one of the causes of the large reduction in drilling costs between 1981 and the present, and this reduction in turn improved the economics of oil drilling. Most probably, an end to the surplus and reestablishment of firm gas markets would aid in a general E&D recovery because drilling costs are unlikely to rebound without a very large increase in drilling—an unlikely event if oil prices remain low. However, the two determinants of the date of an end to the surplus—gas supply and gas consumption—are quite uncertain. Consumption is greatly affected by fuel switching to oil, which in turn is dependent on uncertain oil prices and the ability of gas pipelines to compete with oil on price. Future gas supply is the subject of a substantial divergence of opinion, even more so than is future oil supply, although most forecasts agree that U.S. domestic production will decline in the 1990s and will require added imports, especially from Canada.

Chapter 6

Changes in the Oil Industry Affecting U.S. Oil Production

Changes in the Climate for Oil Investments in the United States and Overseas

The United States represents the most "mature," most intensively drilled of the world's petroleum regions, yet continues to attract a lion's share of exploration and development expenditures. The raw statistics—70,000 barrels found per U.S. wildcat well v. 7 million per wildcat for the rest of the world—paint too extreme a picture of the United States' geologic inferiority, because the nature of its infrastructural development makes economic many low-payoff drilling ventures that could not be attempted elsewhere. It is nevertheless true that geological prospects generally are far superior overseas than in the United States, particularly the Lower 48 States, yet the major oil companies, most based in the United States, continue to spend most of their capital domestically.

An important reason for this appears to be the greater stability and security available within the United States. The major oil companies learned **a** harsh lesson when the Middle East OPEC nations nationalized their oil production and transformed these companies from producers to buyers. Also, the governments of many oil-bearing countries offered only relatively harsh terms for development of their oil resources. Their strategy was stimulated by the belief that oil prices would continue to rise, so that they could benefit by withholding their resources for later development (at much higher prices).[1] **In addition, until recently, hostility to foreign, private investment** of any sort was common among the developing nations.

Industry analysts claim that the business climate for overseas oil investment is improving relative to that of the United States and that, in response, oil company attitudes towards overseas investment are shifting. Industry experts at an OTA workshop unanimously agreed that the large oil companies were shifting their attention to overseas drilling prospects. A recent Salomon Bros. survey found that U.S. oil companies expect to spend 29 percent of their 1987 budgets outside the United States compared to 12 percent in 1986.[2]

Presumably, the reasons for the improving climate are twofold. First, the developing nations have become more sophisticated both economically and politically. They have come to appreciate the potential benefits of private and foreign investments and do not fear as much as previously the accusation that they are selling out to foreign interests. Second, they have come to **recognize**, in light of falling prices, that the delay of oil and gas development has created a substantial loss, rather than a gain, in investment value. These shifts in attitude and understanding have been translated into a variety of concrete actions designed to attract oil and gas investment, **including:**

- removal or raising of former caps on prices paid to foreign producers (Angola, Color-n-bia, Morocco, Canada, Turkey);
- contractors now paid in dollars rather than local currency (Argentina, Chile);
- removal or reduction of prior oil taxes (Canada, Morocco, Trinidad, United Kingdom);
- reduction of royalty rates (Canada, China, Morocco, United Kingdom);
- easing of requirements for training and employing nationals (China);
- flexibility in shifting lease areas (China);
- tax **or** royalty relief for areas deemed difficult **to** explore (Chile, it-eland);
- customs taxes waived for imported materials needed for oilfield operations (Chile);

[1] See M.A. Adelman, "World Oil: Availability and Price: The Next Ten Years," Asian Development Bank, Regional Meeting on Energy Policy, Dec. 11-12, 1986.

[2] *Oil and Gas Journal,* Feb. 23, 1987, p. 30.

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- government loans for seismic surveys, exploratory drilling, etc. (Korea); and
- a variety of more favorable tax and cost recovery rules and other incentives.[3]

Oil industry spokesmen claim that the United States, in contrast to most other countries competing for oil investment, has enacted tax and regulatory changes that substantially worsen the business climate for oil and gas investment,[4] and weaken the Nation's ability to attract such investment. For example, the American Petroleum Institute claims that the 1986 Tax Law will cost the industry $10 billion over the next 5 years, and that the potential reclassification of drilling wastes to the hazardous category by the Environmental Protection Agency could cost the industry up to $8 billion annually.[5]

Evaluating the relative "business climate" for petroleum investments of the United States versus competing foreign nations is difficult. It is dependent on the type of investment being contemplated, the differences in geologic situations, the complex tax, royalty, and regulatory structures in the United States and abroad, differences in the availability of skilled labor and other factors of production, and impossible-to-measure differences in political stability and physical security. In general, we are impressed with the **failure** of most discussions of the opposing climates to deal with the above factors in a careful fashion, and we warn against drawing simplistic conclusions. Also, overseas oil investment can be beneficial to U.S. national security because increased reserves and production outside of the Middle East increases market stability and diffuses the potential for embargoes and price shocks. Thus, although it probably is fair to claim that the **relative** attractiveness of overseas investment is improving vis-a-vis domestic investment, it is not clear whether this shift is towards or away from a desirable balance of overseas and domestic investment.

[3] Barrows Company Inc., New York, NY, "World Incentives for Petroleum Investment, 1980-1 986, " prepared for the United Nations Department of Technical Cooperation for Development.

[4] See, for example, American Petroleum Institute, Two *Energy Futures: National Choices Today for the 1990s, 1986* edition, July 1986.

[5] "API Counts the Burdens of Regulation, " *The Energy Daily*, Dec. 2, 1986.

The Efficiency of E&D Activities

As drilling budgets and other indicators of E&D activity have declined in the face of sharply lower oil prices, the results of that activity, in new fields discovered, volumes of oil added to reserves, and added production capacity also would be expected to decline. However, it is unlikely that these results will drop precisely in lock step with the declines in activity levels, because the "efficiency" of this activity is likely to change also. Understanding how the various measures of efficiency might change is important to projecting future oil reserve additions and production levels.

Few if any of the measures of efficiency in exploration and development have remained stable over the past decade and a half. Such efficiency measures as finding costs (reserves added per dollar spent on exploration and development), rig efficiency (annual footage or wells drilled per active rig), finding rate (reserves added per well or per foot drilled), and completion rate (successful wells/total wells drilled) have varied substantially as oil prices and overall industry activity has ridden a cycle of boom and bust. Because these measures have in the past been so sensitive to changes in economic conditions and especially to changes in oil prices, they are likely to have shifted dramatically–and possibly to continue to shift-in the face of the severe economic dislocations of the past several months.

As an example, finding costs escalated rapidly during the 1970s and very early 1980s, **peaked in 1982 at $13.53/bbl (including revisions) and then have slid substantially in the face of declining oil prices.[6] Reliably projecting future finding costs is critical to projecting future production, and especially critical to production projections that rely on first predicting capital spending and then calculating** reserve additions by using the equation:

Reserves added = (Capital Spending) /(Finding Costs)

To project likely future finding costs, it is necessary both to understand the relationship be-

[6] Arthur Andersen & Co., op. cit. Note that the authors call these values "surrogate" finding costs because they combine expenditures made and reserves added **in the same year,** whereas true finding costs would match expenditures to the actual reserves these expenditures created, usually a few years later.

tween finding costs and the variables affecting them, and to predict the future values of these variables. Unfortunately, finding costs—like the other efficiency measures—are functions of several variables, some of which cannot be easily tracked. These variables, which are not independent of each other, include oil prices, drilling and other service costs, drilling strategies (especially the relative emphasis on deep drilling and other high cost drilling), resource depletion, the availability of promising exploratory acreage, and the technical efficiency of exploration and production technologies. In general, rising oil prices have led to rising finding costs, and vice versa, largely because higher prices stimulate activity aimed at smaller reserve targets or higher cost environments, and lower prices force operators to focus on higher quality (lower finding cost) targets. The past few years have seen sharply decreased finding costs. A fair expectation is that finding costs will remain low if oil prices remain depressed. However, this is not certain, and it will be difficult to predict the magnitude of finding costs with any precision. For example, the energy economist Arlon Tussing, in his testimony of March 6, 1986 to the House Energy and Commerce Committee, predicted that the slide in finding costs that began in 1982 would be found to have continued into 1985, with costs declining about $1.50/bbl from their 1984 value. The recently published Arthur Andersen survey found, however, that 1985 finding costs had gone up from 1984's costs by about $1/bbl, presumably because of the relatively low reported 1985 reserve additions as well as a 7 percent increase in completed well costs.

Another efficiency measure, so-called "rig efficiency" (footage and wells drilled per rig per year), declined from the middle 1970s to the early 1980s as oil prices rose and oilfield activity accelerated. Part of this decline was due to the use of inexperienced personnel and marginal equipment, made possible by the inability of the supply of services to keep up with the demand. Part was due to the spread of drilling activity to more marginal prospects, with lower reserves and perhaps more difficult drilling conditions, and to high payoff but high cost prospects–like deep gas–that required more rig time; this was partly a result of the improved economics of these prospects, and partly an effect of resource depletion as the best prospects were used up,

As oil prices began to decline in 1981, drilling became more efficient as the number of inexperienced drilling crews declined, inefficient rigs were dropped from service, footage and turnkey contracts replaced contracts that paid drillers by the day (day rate contracts offered little incentive for efficiency), and drilling technology improved . . . and thus rig efficiency increased sharply between 1981 and 1985: the industry drilled 89,000 wells in 1981 with nearly 4,000 rotary rigs active; 84,000 wells in 1982 with 3,100 rigs active; and 85,000 in 1984 with 2,400 rigs. Unfortunately, however, the precise dimensions of the actual increase in efficiency are obscured by other factors that also affect measured rig efficiency. These factors include: the proportion of total drilling devoted to exploration, because exploratory drilling is more time-consuming than development drilling; possible changes in the number of rigs that are not included in the data[7]; shifts in the balance of drilling for gas and for oil, because gas wells often require more rig time than oil wells; and shifts in the geographic distribution of drilling, because drilling in some areas, such as the gulf coast, is more rapid than in others, e.g., the Midcontinent and Rocky Mountain Overthrust Belt, because of different rock conditions and other physical factors. Although OTA is not aware of analyses that have systematically isolated the effects of the various factors influencing rig efficiency, several of our reviewers believe that shifts in drilling targets areas important as actual changes in drilling equipment and operational efficiency as causes of the changes in rig efficiency over the past decade and a half.

Another measure critical to many forecasting methods is the "finding rate" of drilling, measured in reserves added per well drilled. [8] The decline in drilling now occurring, and expected to

[7]Commonly used rig counts include only so-called rotary drilling rigs, rigs that drill by rotating a drill bit and its attached drilling pipe.

[8]There are other measures of finding rate, for example, reserves added per exploratory well. Problems in tying together "reserves added' and the specific activities that "created" these reserves are endemic to oil and gas analysis, and no particular measure of finding rate can escape these problems,

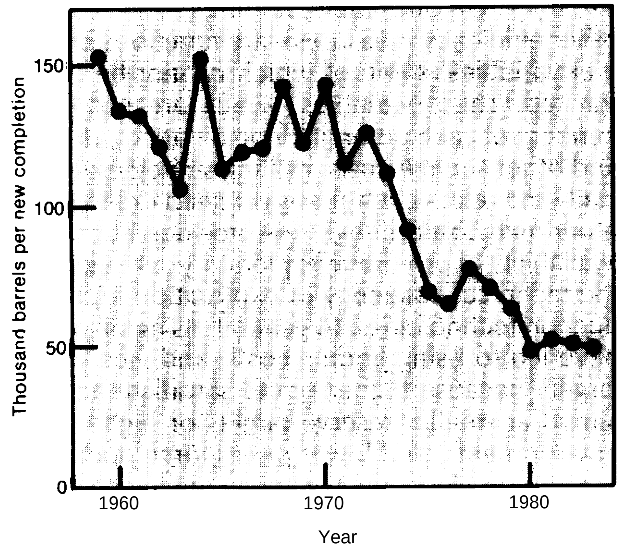
continue, will certainly not be so uniform as to leave the finding rate untouched; a 50 percent decline in drilling is unlikely to yield a 50 percent decline in reserve additions except by some unlikely coincidence.

Figure 9 shows the change in oil finding rate from 1960 to 1983, with "reserves found" computed by assuming a time lag between exploratory drilling and reserve development of 4 years for onshore drilling and 7 years for offshore.[9] The drop in finding rate beginning in the early 1970s may be partly because of resource depletion, but common sense implies that, because of improved economics associated with higher oil prices, a substantial role must have been played by increased drilling of marginal prospects within each region, as well as increased drilling in less productive regions. **The** role of shifting drilling patterns is complicated by the observation that, during the same period, some explorers responded to the price increases by drilling in expensive, high risk regions that promised very high returns per well. However, the lack of exploration success in many of the new drilling areas and the huge number of new marginal wells that were drilled sustain the above interpretation.

OTA believes that the average finding rate achieved by the smaller number of wells being drilled in 1986 might be somewhat higher than recent historical rates; in other words, OTA believes that the finding rate is likely to swing back up the curve in figure ***9.*** Some insight into the potential increase in finding rate can be gained by examining recent regional shifts in drilling. Short-term changes in drilling patterns, as projected by the Oil and Gas Journal,[10] imply that drilling declines will be greatest in areas with relatively low finding rates. Because finding rates differ greatly from region to region, such a shift has great potential to change the national finding rate. For example, adopting the assumption that 1980 to 1984 regional finding **rates will still be reflected in 1986 drilling will result** in an estimated national finding rate for 1986 that is 40 percent higher than the 1980 to 1984 national rate, if the projected shift in drilling patterns holds. This in turn would yield 1986 reserve additions for the United States that would be considerably higher than would be projected assuming a 1 -to- 1 relationship between reserves and drilling rates: specifically, 2.2 billion barrels for the regionally adjusted value versus 1.6 billion barrels without the adjustment, assuming that 46,000 wells (including dry holes) are drilled in 1986. '

OTA does not believe that the "regionally adjusted" estimate of 2.2 billion barrels is the "right" value for 1986 reserve additions. A variety of other factors, such as intraregional shifts in drilling, must still be accounted for. In particular, oil companies are predicting a significant shift away from exploratory drilling towards low risk development drilling; such a shift would tend to lower finding rates and thus lower reserve additions. Also, in the years following 1986, drilling patterns will continue to change even if prices do not. A portion of near-term drilling is tied to

Figure 9.—Oil "Finding Rate" (Reserves Added per Oil Well)



SOURCE: A T Guernsey, ***Profitability Study,*** *Crude* ***Oil and Natural*** *Gas* ***Exploration, Development,*** *and* ***Production Activities in the*** *USA, 1959-7983,* June 1985 for Shell 011 Co

'A. T. Guernsey, *Profitability Study. Crude Oil and Natural Gas Exploration, Development, and Production Activities in the USA, 1959- 1983,* for Shell Oil Co., June 1985.

[10] "OGJ's Revised Drilling Forecast for 1986—U.S. and Canada, " Oil and Gas journal, July 28, 1986, p. 67.

[11] Ibid. It is further assumed that the ratio of completed 011 wells to completed gas wells established in 1980 to 1984 will hold tor 1986.

present lease and other commitments, and these will expire. Company strategies will change, especially since current drilling behavior is affected substantially by its nearness in time to the recent price shock and the turmoil it created. As discussed above, the industry is in a period of transition, and it is far from clear what its exploration and development strategies will look like a few years from today.

Despite the uncertainties created by these factors, it is useful to project future domestic oil production levels by using a "what if" scenario that assumes a continuation of the projected 1986 drilling levels and the optimistic value for reserves/well that reflects only the new geographic distribution of drilling without accounting for factors that might reduce the reserves/well value. The results of just such a projection are discussed in detail in chapter 7.

Changing Oilfield Technology

Continuing evolution of the technology of oil exploration, development, and production is likely to play an important role in the basic economics of oil exploration and development and the size and rate of exploitation of the recoverable oil resource base. For example, advancements in seismic technology that allow for both finer resolution and significant reductions in data collection and analysis costs will be crucial in finding and producing the many thousands of small oil and gasfields. Technological advancements that will substantially decrease production costs—e.g., subsea production systems—are critical to developing offshore fields at today's low. oil prices.

Unfortunately, analysts have had little success at trying to quantify the effects of technological change on oil development. For one thing, there is enormous variability of technical requirements across different prospects, so patterns of technological use are difficult to track. Also, technical capability varies widely among oilfield operators, so that different operators working in the same field and same physical conditions may choose different technical approaches. In our interviews with oilfield operators, OTA was struck by their differing assessments of the importance of technological changes in the past and the potential for such changes in the future. Some describe the past decade and a half as a time of only modest technological change; others describe "tremendous advances in exploration and extraction technologies." [12] It is OTA's impression, however, that the majority of oilmen are pessimistic about the potential for technology to make a big difference in costs in most situations. in particular, oilmen point to the failure of new exploration technology to cause a measurable change in dry hole risk, and the steady downward progression of performance measures such as reserves added per well.

OTA believes that technological change has played an important role in oil exploration and development during the past decade or two, but that other forces affecting oil markets, especially the price shocks following the Yom Kippur War and the Iranian revolution, obscured the effects of technology. Most importantly, the hyperinflation of oilfield services starting in the middle 1970s simply overwhelmed any statistical evidence of the many cost-cutting effects of new and evolved technologies, Nevertheless, the following technological changes clearly played a significant role in stimulating the movement of resources into the recoverable range, whether by affecting the economics of prospects that previously could have been recovered but had insufficient profit potential, or by moving resources out of the technically unrecoverable range to the recoverable:

- significant improvements in the longevity of drill bits;
- movement of seismic interpretation from strict reliance on mainframe computers to widely available minicomputers, and the development and spreading use of 3-D seismic techniques;
- numerous advances in enhanced oil recovery technologies;
- development of subsea completion and floating production systems, that both allow

[12] H. R. Linden, "Impact of Advances in Science, Technology and in the Understanding of the Terrestrial Origin of Hydrocarbons on the Role of Natural Gas and Crude Oil in Meeting Future Primary Energy Needs," Gas Research Institute, July 18, 1986.

the exploitation of smaller offshore fields and lower the risk of certain high-risk large fields;

- improvements in offshore platforms, especially movement to lighter, less expensive designs (e.g., the tension leg platform);
- development of measurement-while-drilling techniques[13] that help avoid mishaps, permit more accurate directional drilling, and reduce the probability of missing productive zones;
- continuing evolution of various subsystems, e.g., drilling mud systems;
- development and/or improvement of sophisticated nonseismic exploration techniques, including remote sensing techniques and geochemical techniques;
- vast improvement in fracturing techniques for low-permeability reservoirs, especially critical for gas recovery;
- development of horizontal drilling techniques that allow economic recovery from thin pay zones and promote full field development at lower costs; and
- development of more sophisticated mathematical models for reservoir simulation that allow better design of well placement for field development.

OTA has become aware of several recent technological improvements that demonstrate the potential of advanced technology to make important changes in the economics of exploration and development:

- A factor of two improvement in the resolution capability of seismic imagery, which has important implications for development well placement and exploration for small fields.
- The recent development of improved nuclear logging tools that can detect oil and gas behind well casing. This will allow the identification of producing zones that were missed during initial exploration, with particular implications for increasing production from existing wells.
- The development of so-called stratigraphic-seismic techniques which can improve exploratory well success.
- New methods of 3-D seismic mapping of reservoirs that provide similar detail at half the cost of previous approaches. Although 3-D seismic is a powerful exploratory and development drilling tool, its use has been limited because of its cost.
- New developments in chemical enhanced oil recovery (EOR) that have lowered the threshold of profitable application from $25 to $30/bbl to about $20/bbl for this type of EOR. This will offer major opportunities for implementing EOR more widely than previously expected, with higher recovery efficiencies.
- New techniques for three-phase flow measurements of oil, water, and gas that will allow the elimination of expensive test separators in offshore platforms, lowering somewhat the economic threshold for offshore recovery.
- Substantial decreases in the cost of multicomponent seismic imagery, which uses standard compressional waves in combination with shear waves to allow higher spatial resolution, direct identification of rock types, measurement of porosity and permeability and direct hydrocarbon detection. A new multicomponent seismic source costs only about 50 percent more than compressional seismic, which will open this technology to practical application.
- The initial uses of CAT scanning to observation of flow inside porous rocks. Continued research should lead to improved mathematical modeling of non-uniform flow inside reservoirs, critical to optimizing EOR design.
- The first Alaskan well using "extended reach horizontal drilling" was drilled by Standard Oil and tripled the output of conventional drilling in the same formation. By allowing the development of areas where the pay is too thin to develop with conventional drilling, it is hoped that this technique will allow increased recovery at Prudhoe Bay.[14]

The continuing development of new and improved technologies, especially focusing on cutting costs, will be a crucial determinant of the fu-

[13] Measurement of rock permeability, and porosity, hydrocarbon presence, and other important variables without shutting down drilling and removing the drill "string."

[14] Arlon R. Tussing & Associates, Inc., *The Property-Tax Base of the North Slope Borough, Alaska*, May 1, 1986.

ture success of the industry in reducing the decline in oil reserves and production rates expected to accompany lower oil prices. Although the level of effort in oilfield R&D is difficult to track because it is hidden in many different accounting "cub byholes," most industry observers feel that it has been cut back substantially. For example, the former president of Exxon Research & Engineering Co. has estimated that research, development, and engineering within the industry has been cut by at least 30 to 40 percent in the last 3 years.[15]

If the observers are correct, and if the industry wishes to be able to prevent large production drops, the industry probably is doing the opposite of what it should be doing, despite its need **to** economize in response to drastic cuts in revenues. In the face of drastic changes in their economic environments, other industries have achieved large cuts in production costs. It seems reasonable to project that the oil industry would stand a good chance of achieving the same.

According to the French Petroleum Institute (Institut Francais du Petrole, or IFP), potential near-term improvements in oilfield technology can offer very substantial cost savings. IFP identifies key advances as:

- optimization and automated control and management of drilling, based on the most sophisticated use of measurement-while-drilling, offering a potential reduction in drilling cost of 30 to 35 percent;
- optimization of the understanding of reservoirs as the result of progress in the modeling of their dynamic behavior, leading to better well placement and the need for fewer development wells;
- further development of seismic imagery to help in understanding reservoir behavior, including increasing its power of resolution to provide detailed images of the reservoir; development of seismic devices that can operate inside the well bore, leading to the same result as above as well as a higher success rate for exploration wells;
- improvement in enhanced recovery techniques, including drilling techniques such as horizontal drilling; and
- continued improvement in offshore platforms for shallower waters, and development of "all on the bottom" systems for deeper waters.[16]

IFP estimates that full success of such a technology development program and its successful implementation could create substantial savings in the overall technical costs of production (including exploration and development costs), namely:

Onshore fields	savings of 20 to 25 percent
Conventional offshore fields	savings up to 30 percent
Deep offshore fields:......................	savings of 30 to 50 percent[17]

If the IFP estimates are valid, then technological advances could move a large share of petroleum resources from the subeconomic to the economic range at $15 to $20 oil prices. The majority of industry reviewers of the draft version of this report were quite skeptical of the **IFP** estimates and felt they were substantially overoptimistic. There were, however, a minority of "technology optimists, " some of whom are familiar with current research and development programs, who are hopeful about the potential for achieving cost savings of this magnitude. These hopes are, of course, dependent on the industry somehow resisting the current trend towards reduced R&D expenditures and focusing a substantial effort on cost-saving technology.

Deteriorating Industry Infrastructure and the Potential for a Rebound in Oil Production

Introduction

Although the current decline in U.S. domestic oil production and the expected further production declines are dismaying in and of themselves, the declines translate into problems for U.S. national security and economic stability only to the extent that production levels cannot rebound

[15] Edward E, David, quoted in the "News and Comment' section of Science, vol. 232, June 27, 1986.

[16] J. Favre, "Research and Innovation To Get Out of a Crisis: The Cost-Reduction Policy of the Institut Francais du Petrole," presented at the Conference on Impact of Price Declines on Oil Exploration, Development and Financing, Dallas, TX, Sept. 3-5, 1986.

[17] Ibid

soon after the onset of a physical shortage of oil or a large increase in its price. In fact, if production **could rebound in this way, future disruptions might be less probable.**

In general, a decline in domestic production will not be easily reversible. it is true that some of the wells that are shut in can be placed back in production (although the number of such wells will diminish sharply after a few years). I n addition, some EOR projects that are moth balled can be restarted (although it may take a few months for additional production to start flowing and the production response to the EOR may be reduced). In general, however, significant amounts of incremental production can be added only by reworking old wells, by drilling new ones, both exploratory and development, and by developing new EOR projects or expanding existing projects. All of these activities are capital-, manpower-, and equipment-intensive, and gaining significant increments of production—which will require tens of thousands of individual drilling and other projects—will be time-consuming even if capital, equipment, and manpower are plentiful.

There are now substantial doubts as to whether capital, equipment, and manpower **will** be plentiful, given the deterioration of the industry's infrastructure that has occurred over the past few years and the loss of the confidence in steadily rising oil prices that marked the rapid buildup of industry infrastructure that took place in the 1970s, Many in the oil industry are arguing that, once U.S. oil production declines to levels well below those of today, a production rebound in response to a sudden price hike would be extremely slow, would be accompanied by massive inflation in equipment and manpower costs (as well as inflation in associated costs such as leasing bonuses), and would likely fall well short of recapturing the losses in production rates. Examining this hypothesis requires an evaluation of the factors of production and the timetables for each phase of the production cycle.

People

There is widespread concern in the industry that the current depression in E&D activity and the accompanying layoffs, company failures, and crippled hiring programs will rob the industry of a major portion of its most valuable personnel. Overall industry employment has dropped from its 1982 high of 708,000 to 425,000 in August of 1986. Oilfield service company employment dropped from 435,000 to 206,000 in the same period, indicating that this sector has absorbed the brunt of the layoffs. A special concern is that the very pessimistic perception on college campuses of the industry's future and the virtual halt of industry recruitment efforts will decimate well-established university programs in petroleum geology and engineering. Another concern is that many of the employee reduction programs are focusing on the older, more experienced (and more highly paid) professionals, and that the industry is thus losing its most effective workers. This concern is intensified by the 3-year training period said to be necessary for skilled oil service workers and the 7- to 10-year period needed for professionals.

The seriousness of these concerns is by no means settled. For one thing, the drilling boom of the late 1970s and early 1980s attracted very large numbers of students to petroleum-related programs. For example, the Society of Petroleum Engineers reports that a large oversupply of petroleum engineering graduates has existed since 1980-81, and expects this condition to last at least through the end of the decade. This situation probably exists in other petroleum fields as well. Although many of these graduates as well as the laid off engineers, geologists, and other professionals and skilled workers will find work in other fields, it is by no means certain that they will be "lost" to the industry. Previous experience with other industries—e.g., in aerospace technologies —implies that many of these trained personnel can be recaptured by the industry in the event of a sudden leap in oilfield activity, at least if there is convincing evidence that the new jobs will be stable. Further, the possibility of "recapture" should be strongly influenced by the attractiveness of replacement jobs. Although OTA is not aware of data on the success of laid-off oilfield workers in finding employment, and on the relative salary levels of replacement jobs, laid-off manufacturing workers in similar situations have tended to take substantial salary cuts, and oilfield workers would likely have to do the same.

Capital Availability

The opportunity for a rapid rebound in oil production will be possible only with a large increase in cash flow, presumably from a substantial oil price increase, or a massive influx of outside capital into exploration and development activities. During the drilling boom of the 1970s and early 1980s, attracting such capital was relatively easy because of favorable tax policies and because of a widespread perception that inexorable increases in oil prices would rescue even weak investments so long as some producible oil was found. In contrast, capital availability to fuel a potential production rebound is likely to depend primarily on skeptical analyses of the economic fundamentals of the individual oil prospects using conservative assumptions about future price growth. Investors will have to be convinced that the economic conditions appearing to favor new oilfield investment are stable, or else that their investment will be safeguarded against a return to low prices. Consequently, the potential for a successful rebound in U.S. oil production will depend strongly on the precise geopolitical circumstances—and the perceptions of these circumstances—that accompany the events driving the oil market towards shortages and/or sharply higher prices. Also, because perceptions and reality clearly do not have to—and often do not—agree, and because a variety of unpredictable factors fuel perception, considerable uncertainty exists about the potential response of capital markets to an oil market situation in which a rebound might be attempted.

Some analysts, seeing that the independent producers' supply of outside capital (from banks and private and public drilling funds) has virtually disappeared, and recognizing that internal cash flow was the primary source of the industry's investment dollars even when outside capital was readily available, assume that any rebound will have to be funded from internal funds. In OTA's view, this is unrealistic. The current withdrawal by banks and funds from oil investment seems a logical short-term response to the large financial losses sustained by these capital sources and the widespread perception of massive instability in oil prices. Eventually, however, a portion of these capital sources will return to the industry if profitable investment opportunities are perceived to be available. The timing of this return, however, being as much a psychological event as a financial one, is highly uncertain.

It is also important to recognize that **the drying** up of internal capital is not universal to the industry, because many of the integrated companies retain substantial cash flows from their downstream operations, and even the reduced cash flows from production can buy considerably more drilling services than would have been possible in the early 1980s, **because of the substantial reductions in oilfield costs.**

Equipment

Equipment availability is an additional concern in the event of any attempt at a rapid restoration of lost U.S. oil production. As noted above, such a restoration will involve the drilling and equipping of many thousands of new wells in addition to the completion of thousands of other production-related and equipment-intensive projects.

Although the industry has expressed substantial concern about equipment availability, there currently is a substantial surplus of oilfield equipment both in a ready status and in storage. At the peak of the drilling boom in 1981 there were over 5,000 land drilling rigs available in the United States, the majority of them constructed within a few years of that date. Although utilization rates were high during the boom (79 percent in 1981, for example), most industry observers will agree that rig efficiency was low. Indeed, the industry drilled nearly 86,000 wells in 1984 using only 2,400 rigs, whereas nearly 4,000 rigs drilled 89,000 wells in 1981.[18] Also, many of the wells drilled in 1981 were drilled with only marginal prospects for success. A more efficient industry could have added the same volume of reserves with far fewer rigs than were actually deployed.

[18] Some part of the difference in rig efficiency is said to be due to a reduction in deep drilling for gas after 1981. Average well depth declined by only 250 feet during the period, however. Other factors aside from actual improvements in equipment and operational efficiency that may have contributed to rig efficiency changes include shifts in the locational distribution of drilling and changes in the proportion of exploratory drilling.

Although a "target" rig count for a successful rebound is a speculative figure at best, a return to a 3,000- or 4,000-rig onshore fleet seems excessive. If a 2,500 rig count is a reasonable target level for a production rebound, it appears likely that the capability for quickly assembling that size fleet will remain viable for at least several years. Although some of the used equipment has been sold to foreign operators, overseas activity levels seem unlikely to expand sufficiently to warrant concern over additional losses. Other areas of concern include the cannibalization of rigs to keep the current fleet operating, the potential for scrappage, and the potential for deterioration due to improper storage. Cannibalization is occurring and will eat into rig availability, but there are so many excess rigs that this should not be a major problem for a considerable time. Little of the equipment is likely to be scrapped, however, because in most cases the price of scrap steel is low, and dismantling is expensive. Finally, although concerns about proper storage are well founded, much of the equipment now out of service is simple and durable (see table 31), and the best rigs are the most likely to be properly moth balled and maintained. An indication **of industry recognition of the value of proper storage is the formation of** services designed to handle some or all aspects of storage for rig owners.[19]

In conclusion, although an attempt to add quickly to drilling rates will likely run into some bottlenecks, especially in high volume goods such as drill pipe and drill bits, for the next few years equipment should not be a major constraint on a drilling revival.

The Resource Base and Availability of E&D Opportunities

The turnaround in U.S. oil production that took firm hold in the late 1970s owed much to the large "inventory" of potential drilling opportunities amassed during the previous decades of low oil prices. By going back to old well logs and field records, geologists and engineers could identify many thousands of opportunities that were uneconomic at $3/bbl yet low-risk, profitable producers at $10 and up. Although most were modest producers, in the aggregate they made a significant contribution to total U.S. production. In addition, Alaskan production was just beginning to start up in the early 1970s and provided an additional, massive boost to U.S. production levels.

[19] L. R. Aalund, "Rig Owners Grapple With Offshore Stacking," *Oil and Gas Journal,* Sept. 15, 1986.

Table 31.—Drill Rig Equipment: Storage and Availability

Derrick: The derrick is made to be stored in the open, and should not present a problem.

Mud pumps: Mud pumps should be stored out of the weather, but are relatively easy to store. Lots of upgrading was done to the fleet's mud pumps in 1983 to 1984, and most should be in good condition.

Drill pipe: Drill pipe is quite likely to be sold off and may represent a high potential for a *short-term* shortage in case of a rebound in drilling activity.

Draw works: Draw works are vulnerable to the elements, but still relatively easy to store properly.

Prime ***movers:*** Engines are most likely to be sold to other industries, and could be in shortage in a rebound.

Drill bits: Since drill bits do not last long, a rebound will require substantial bit manufacturing capability. This capability is being rapidly diminished, and drill bits may be in shortage in a rebound.

SOURCE Office of Technology Assessment, based on discussions with equipment suppliers.

Prospects for a rebound in production following a substantial price increase will depend in large measure on whether or not a similar inventory exists now of drilling and other production-related opportunities. Without such an inventory, a substantial boost in production would have to wait a number of additional years to work through the early stages of the production cycle . . . stages that are bypassed when low risk opportunities in discovered fields can be identified. The importance of such an inventory is further enhanced by the imminent decline of Alaskan production and the lack of any replacement producing province.

The issue of whether or not the inventory of oil opportunities will be adequate to support moderate levels of drilling activity for a number of years is basically the same issue of continued field growth that appears in Section Vd on the Resource Base. As discussed in that section, there remains substantial controversy about the potential for field growth through conventional drilling of the existing U.S. oil and gas fields. Two im-

portant questions are whether many opportunities remain to attain additional reserves through extension wells and infill drilling designed to produce mobile oil that would not have been **produced at previous levels of well spacing, and whether or not recently discovered fields, which are on the average smaller than their predecessors, will grow at historical rates. The former question remains controversial because of continuing disagreements about the actual level of heterogeneity existing in many of the Nation's oilfields.**

The Restructuring of the U.S. Oil Industry

Introduction

During the 1980s the U.S. oil industry has been undergoing a transition that has left virtually no segment of the industry unchanged. "Restructuring" is the overall term commonly used to describe the fundamental shifts in the size and composition of the domestic oil industry as a whole and the changes in internal organization and direction of individual companies. The current restructuring is reflected in the increasing consolidation of the industry and in widespread, often drastic adjustments in the operational and financial structures of individual companies and their petroleum investment strategies. This chapter describes some of the recent changes in the U.S. oil industry and the possible future implications for continued investment in domestic exploration and production.

Well before the 1986 oil price plunge, many of the major and independent oil companies embarked on ambitious operational and financial restructuring efforts in response to conditions creating increased uncertainty about oil's future profitability. Restructuring has taken varied forms including:

1. corporate mergers, acquisitions, and major asset sales and purchases;
2. operational and organizational changes to streamline business divisions and cut costs by combining or eliminating functions and, often, reducing the number of employees;
3. asset "redeployments" with companies expanding in operating segments and geographic areas where they perceive an advantage and eliminating less profitable operations through sales, asset writedowns, and liquidations;
4. adoption of financial strategies designed to enhance the market value of the company by increasing dividends, buying back stock, changing debt levels, or creating new equity investment opportunities (e. g., master limited partnerships);
5. increased use of joint ventures and other risk spreading arrangements for exploration and development projects; and in some extreme cases,
6. reorganization of assets and liabilities under the protection of bankruptcy proceedings.

There is general agreement that the current restructuring was prompted by prevailing conditions in the industry following the 1981 boom :20

1. There was a worldwide surplus in oil production capacity and excess capacity in refining and marketing operations as a result of the higher oil prices and industry expansion in the 1970s.
2. Oil consumption declined from 1979 to 1983 due to higher prices and conservation efforts and the recession; many industry forecasts predicted that annual growth in oil demand would be less than 1 percent per year through the year 2000.
3. Excess oil production capacity, reduced demand, and the breakdown of OPEC set oft a steady decline in oil prices in 1981. By 1983 there was a growing consensus that oil prices would remain low, and perhaps decline further, until at least the early 1990s.

[20] See, tor example, statement of T. Boone Pickens, jr., in *Legislation Affecting Oil Merger Proposals: Hearing on S. 2362a Bill to Amend the Mineral Lands Leasing Act of 1920 and for Other Purposes Before the Subcommittee. on Energy and Mineral Resources of the Senate Comm. on Energy and Natural Resources,* 98th Cong., 2d sess. 320 (1984), and supplementary material provided by Frank W. Bradley of Chevron Corp., *id.* at 536. (These hearings are hereafter referred to as *Legislation Affecting* 0)1 *Merger Proposals.)* See also *Impact of Oil Company Mergers: Report to the United States Senate, Prepared by the Majority Staff of the Senate Committee on Energy and Natural Resources,* S. Prt. 98-206, 98th Cong., 2d sess. (1984).

4. Many oil industry managers and investors were disappointed by the relatively high finding costs and the difficulty in finding and producing new domestic oil reserves, particularly in the light of the massive investments in exploration. There was a growing perception among some major oil companies that because of the past extensive onshore exploration in the United States, there were now fewer "good" U.S oil prospects remaining.

Some industry analysts would add to the foregoing conditions: concern over possible changes in Federal tax and oil and gas leasing policies, the pressures on companies from increasingly aggressive institutional investors demanding greater short-term returns from their holdings, and the fear of possible hostile takeover offers by corporate raiders.

Although changes in capital structures, mergers, acquisitions, liquidations, and bankruptcies are not unusual in the oil industry, recent years have seen a high level of these activities.[21] These widespread occurrences, coupled with the general conditions of overcapacity, reduced demand, and declining prices suggested to some observers that the domestic industry had entered a period of fundamental structural change before it began to experience the adverse effects of the plunge in world oil prices in 1986.[22] If the current restructuring is indeed symptomatic of the maturity of the U.S. oil industry, rather than the result of cyclical influences of world oil prices, this further suggests that a return to the slightly higher oil price levels preceding the price slide will not stem the eventual contraction of the industry and the decline in U.S. oil production. But there are others in the oil business who do not share the view that the U.S. industry is in inevitable decline. To them restructuring is desirable, but marks a normal and healthy evolution of the industry in response to changing conditions. They point out that the oil industry has been through similar periods of expansion and contraction in the past.

Restructuring has already had profound effects on the industry and on oil companies and their investment decisions. The success of their restructuring efforts and other strategies adopted by individual companies in response to low oil prices may well determine their economic viability in a new era of more volatile oil prices and stronger competition from foreign oil imports. The cumulative result may be oil's transformation into a smaller, more efficient industry with fewer companies and a different approach to business. But a smaller industry may not conduct as extensive or aggressive an exploration program to replace domestic reserves and this could increase U.S. reliance on foreign oil. Moreover, there is concern that the sharp increase in corporate indebtedness associated with recent mergers, acquisitions, and internal restructuring, coupled with declining earnings due to low oil prices, will mean sharply reduced expenditures for exploration and development in the short term as available cash flow is diverted to debt repayment. **In the long term, this trough in exploration expenditures could contribute to a decline in oil production.**

Conditions Causing Restructuring

World oil trends in the 1980s began to raise concerns about the future profitability of the domestic industry. Even as oil revenues soared in 1979-82, present and future earnings were being undermined by growing worldwide overcapacity in upstream and downstream operations, lower oil prices, declining demand, and changes in domestic tax policies. Additionally, the indus-

[21] Materials prepared for the Senate Banking Committee indicate that the number of mergers and acquisitions from 1983 to 1985 has been much higher than during the 1970s and has involved substantially more funds than ever before. According to *Mergers and Acquisitions*, over $122 billion was spent on completed transactions in 1984; oil and gas industry transactions probably were one third to one half of that total. See *Impact of Corporate Takeovers: Hearings on the Effects of Mergers on Management Practices, Cost, Availability of Credit, and the Long-Term Viability of American Industry Before the Subcommittee on Securities of the Senate Committee on Banking, Housing and Urban Affairs*, 99th Cong., 1st sess. 591-593 (1985). (Hereafter referred to as *Impact of Corporate Takeovers.)*

[22] U.S. Congress, Joint Economic Committee, "The U.S. Oil Industry in Transition: Causes, Implications, and Policy Responses," Comm. Print, 99th Cong., 2d sess., S. Prt. 99-154, May 20, 1986, at 9. This study by the Business School at Southern Methodist University concludes that current trends in the oil industry are characteristic of the mature phase of an industry life cycle: excess capacity, low growth, business failures and consolidation. The study compared the oil industry to other "distressed" mature domestic industries in transition such as steel, textiles, automobiles, and agriculture.

try **was becoming more vulnerable than in the past to rapid changes in oil prices as more and more oil was sold on the spot market or at spot-market-related prices.**

One clear **implication of these trends was that the majors could no longer** rely on rising prices and expanding product sales to assure future profits growth. The earnings of major U.S. oil companies did not reflect much of the initial oil price drop in 1981 to 1985 because most of the excess price over $20/bbl was taxed away by the windfall profits tax (WPT). The contribution to cash flow in dollars per barrel of crude oil equivalent for major U.S. companies after deducting the WPT fell only 1.6 percent between 1981 to 1984.[23] The independents, who generally carried a smaller WPT burden, however, were more seriously affected by the steady slide in oil prices. By 1985, many independents were already in financial difficulty because of the combined effects of lower oil prices and lower prices for natural gas. But as the price fell below $20/bbl in 1986, cash flows for both majors and independents were squeezed.

The prospects of slow demand growth and declining oil prices forced managements to reformulate their long-term business plans to decide how best to protect the future profitability of their companies. This reassessment accompanied the emergence of a management philosophy that places greater emphasis on financial performance and short-term returns to shareholders than on finding oil. With world oil industry conditions largely beyond their control, companies began to look inward for ways to cut costs and maintain profits and to reexamine the assumptions underlying their business strategies. Restructuring and a move away from continued heavy investment in domestic oil exploration have been two results.

Many integrated companies began to shift away from their past emphasis on maintaining a secure source of domestic reserves to supply their refining and marketing operations and to end the traditional priority given to recycling a high proportion of their production revenues back into exploration and development activities. The cutback in domestic exploration also marks a reevaluation of the potential for finding additional large oilfields in domestic frontier areas. Oil industry observers and company annual reports indicate that several companies appear to have altered their views on the economic viability of conducting a broad-based exploration and development program in the Lower 48 States at prices experienced in recent years. For example, Lodwrick C. Cook, the Chairman of the Board and Chief Executive Officer of ARCO, told his shareholders:

> [I]n the lower **48 we** intend to maximize productivity of existing fields and not try to replace production through further exploration in this declining region—though we will buy reserves when good opportunities come a long... Essentially we've shifted away from the high-risk, major-stakes emphasis of recent years and toward projects that can be expected to produce economic results more reliably. As the price of crude oil increases we can step up exploration again, although not on the large scale of recent years. **Results of the industry's late 1970s, early 1980s drilling boom weren't that encouraging—at any predictable price.** (Emphasis added.)[24]

Many majors and independents have not been able to replace their U.S. oil and gas production with new reserves despite heavy investment in domestic exploration, and the reserves they did find came at a high cost. For example, as shown in table 32, oil and gas reserve additions for many major oil companies, excluding purchased reserves, fell short of replacing annual production over the period 1979 to 1985. Even when purchased reserves are taken into account, many companies still did not replace depleted reserves. Over the same period, the U.S. industry replaced about 92 percent of its liquids production.

The poor success of some exploration efforts is also reflected in the relatively high implied finding costs incurred by some firms over the years 1979 to 1985. The average weighted implied finding cost for the major oil companies shown in table *32* was *$10.58* per equivalent barrel in 1979

[23] U.S. Department of Energy, Energy Information Administration, *Performance Profiles of Major Energy Producers 1984*, tables 21 and 22.

[24] Remarks of Chairman Lodwrick C. Cook at the 1986 annual shareholders meeting, reprinted in Atlantic Richfield Co. 1986 First Quarter Report, at 12, 15.

Table 32.—U.S. Oil and Gas Reserves Replacement as Percentage of Production, 1979-85, and Domestic Implied Finding Costs

	Production replacement excluding purchases and sales (weighted average 1979-85)[a]	Production replacement including purchases and sales (weighted average 1979-85)[b]	Implied finding costs $/Bbl oil equivalent (weighted average 1979-85)[c]
Major integrated oil companies:			
Amoco Corp.	109.0%	11 2,8%	$7.91
Arco	103.9	108,5	7.05
Shell Oil Co.	99.2	147.6	7.46
Chevron Corp.	81.4	169.3	9.48
Murphy Oil Co.	75.9	77.8	15.19
Exxon Corp.	75,6	77.2	9.93
Mobil Corp.	72.1	121.3	10.18
Phillips Petroleum Co.	69.5	98.3	9.53
Unocal Corp.	65.6	66.25	9.62
Sun Co.	58.1	79.3	11.05
Kerr-McGee Corp.	51.7	62.4	21.09
Standard 011 Corp.	22,2	23.0	26.61
Texaco, Inc.	Neg.	47.8	Neg.
Independent producing companies:			
Noble Affiliates,	150.7	151.6	9.04
Mitchell Energy & Development Co. .,	1423	146.7	1041
Pogo Producing Co.	93.6	93.8	1417
Sabine Corp.	88.5	1 17.4d	1204
Pennzoil Co,	86.4	102.3	8.91
Louisiana Land & Exploration Co. ...	39.8	40.7[e]	21.91

[a]Replacement includes reserves added through discoveries, extensions Improved recovery and revisions of previous estimates
[b]Replacement includes reserves added through discoveries, extensions, improved recovery and revisions Of previous t? stimates plus the effects of reserves purchases and sales
[c]Finding cost excludes proven reserves purchases except where property acquisition costs do not break out proven and unproven acreage
[d]Excludes reserves distributed to the Sabine Royalty Trust
[e]Excludes reserves distributed to the LL&E Royalty Trust

SOURCE Office of Technology Assessment from Donald F Textor Todd L Bergman Cristina Tiscareno Finding Cost and Reserve Replacement Results 1979-1985 Goldman Sachs Research April 1986

to 1985. There was a wide range in reported finding costs among these companies, from $7 to over $26/bbl. Several companies had extremely poor results in their domestic exploration programs with implied finding costs well above the $5 to $9/bbl average purchase cost of proven reserves over the same period .25

High finding costs translate into a low profit margin per barrel (or even a loss) if prices do not rise. The declining profitability of newly added reserves was becoming apparent even at prices over $20/bbl. This trend is reflected in several commonly used indirect measures of the profitability of exploration and production activities:

- **Discounted Future Net Cash** Flows.—A measure of the present value of all proven oil and gas reserves derived by applying year-end oil and gas prices to estimated future production to yield expected production revenues flows, then subtracting estimated future production and development costs and future income taxes, and discounting the resulting annual future net cash flows by an annual discount rate (usually 10 percent).
- **Present Values Added Through Exploration and Development.—The present value of new reserves added as a result of exploration and development activities in a given year. This measure is calculated** for newly discovered reserves in the same manner as discounted future net cash flows above.
- **Value-Added Ratios.–Two** measures of the returns on exploration and development investments. The **value-added ratio for exploration and development** is expressed by comparing the present value of new reserves added by exploration and development activities with the costs incurred to acquire, explore and develop the reserves. The **value--added ratio for all sources** compares the present values of reserves added through ex-

[25] Arthur Andersen & Co., *Oil & Gas Reserves Disclosures: 1981 to1985 Survey of 375 Public Companies, s-46 (1986).* and estimates provided by Strevig & Associates in ''Prices for Reserves Purchases on the Upswing, " *Oil* & Gas *Journal,* Feb. 16, 1987, at 46.

ploration, revisions, and reserves purchases (less sales) to the total costs incurred to obtain the reserves including amounts paid to buy proven properties.

The above measures are calculated assuming that all future production is at year-end prices and lifting costs; the year-end prices are not escalated unless the reserves are covered by a contract provision requiring such an adjustment. The measures are recalculated each year to reflect changes in prices and costs and are required by the Securities and Exchange Commission (SEC) to be included in many oil company annual reports. Although companies generally disclaim the accuracy of these measures as indicators of future E&P profitability, the measures do allow for comparison between companies and for identification of industry trends.

According to an Arthur Andersen & Co. analysis, shown in table 33, projected future net cash flows for 375 of the largest publicly held oil and gas companies remained fairly steady in 1981 to 1984, with the initial price decline offset somewhat by lower lifting costs and taxes.[26] In 1985 future net cash flows dropped 8 percent at year-end prices of about $25/bbl. At mid-1986 prices of $15/bbl and less, the future cash flows from proven reserves will likely be substantially less. Some analysts believe that the increases in reserve values experienced as a result of the price increase in 1979 to 1981 will probably be wiped out by the 1986 price fall.

[26] Arthur Andersen & Co., *Oil and Gas Reserves Disclosures: 1981-1985 Survey of 37.5 Public Companies,* at s-37 to s-38.

Moreover, the values of new reserves added through exploration and development by major oil companies worldwide declined between 1981 to 1985 as shown in table 34. The Arthur Andersen study attributed the decline to the fact that much of the majors' new reserves came from costly improved recovery techniques and exploration in high cost remote areas .27 The value added on a per-equivalent barrel basis for the 375 companies analyzed in the study has also declined since 1982. The majors generally posted the lowest added value per barrel from exploration. The profitability of these low value reserves is expected to be highly sensitive to price changes.

The troubling outlook for the profitability of exploration investments is indicated when the values of reserves added are compared to the costs of discovering and developing the new reserves. As shown in table 35, since 1981, companies have spent more looking for oil and gas (the "costs incurred for exploration and development") than the present value of the reserves found. Only in 1985 did new reserves values exceed costs incurred, primarily because the costs declined more than the net decrease in the value of reserves added. The value added from all new reserve sources, including exploration, development, revisions and net purchases and sales, however, significantly exceeded the related costs incurred in the same period.

[27] An additional reason for the low present values of the new reserves posted by the majors is that many of these discoveries have long lead times before commercial production and cash inflows begin, In contrast, many of the non-majors' reserve additions have relatively short leadtimes before production and income start,

Table 33.—Valuations of Proved Reserves

	Discounted future net cash flows[a] (billions)									
	In the United States					Worldwide				
	1985	1984	1983	1982	1981	1985	1984	1983	1982	1981
Majors	$109.2	$118.9	$115.0	$120.9	$122.5	$167.4	$172.8	$169.9	$176.1	$181.1
Independent	13.8	14.8	14.8	14.7	13.2				17.2	15.0
Pipeline/utility	7.3	7.3	6.8	6.3	5.6	9.1	9.1	8.6	8.8	7.6
Diversified	23.1	25.6	25,5	26,3	25.7	38.9	40.9	39.1	40.7	41.1
Total	$153.4	$166.3	$162.1	$168.2	$167.0	$232.3	$240.0	$234.7	$242.8	$244.8

[a] Based on SFAS No, 69 criteria.

SOURCE Arthur Andersen & Co "Oil & Gas Reserves Disclosures 1981-85 Survey of 375 Public Companies," 1986.

Table 34.—Values Added Through Exploration and Development—Worldwide

	Present value of reserves added[a] (millions)					Per equivalent barrel				
	1985	1984	1983	1982	1981	1985	1984	1983	1982	1981
Majors	$15,447	$17,926	$16,760	$18,948	$22,071	$5.83	$5.24	$5.65	$7.61	$ 7.39
Independents	2,007	2,672	2,362	3,221	3,447	8.38	10.71	10.41	11.67	11.38
Pipeline/utility	1,850	2,009	1,576	1,597	1,583	8.61	9.91	10.37	5.66[b]	9.40
Diversified	6,677	7,927	5,988	7,712	8,262	8.44	9.08	8.65	10.31	10.05
Total/weighted averages	$25,981	$30,534	$26,686	$31,478	$35,363	$6.67	$6.43	$6.61	$8.29	$8.26

[a]Extensions and discoveries plus improved recoveries.
[b]Includes the effects of one company's downward quantity revisions in 1981, subsequently reflected as quantity additions in 1982.

SOURCE' Arthur Andersen & Co., "Oil & Gas Reserves Disclosures: 1981-85 Survey of 375 Public Companies, " 1988.

Table 35.—Value Added Ratios-Worldwide

Exploration and development	Five-year average	1985	1984	1983	1982	1981
Majors	91 "/0	100%	780/o	920/o	890/o	95 "/0
Independents	99	92	133	106	92	84
Pipeline/utility	87	102	101	90	73[a]	71[a]
Diversified	103	119	130	100	91	87
Weighted average	93 "/0	103 "/0	890/o	94 "/0	890/o	920/o
Ail sources						
Majors	144"/0[b]	177"/0[b]	145"/0	1300/0	1lOO/o	1620/o
Independents	127	96	147	116	127	141
Pipeline/utility	132	131	152	140	183[a]	51a
Diversified	145	125	184	123	115	176
Weighted average	143%[b]	158%[b]	150%	1280/o	1160/0	1590/0

[a]Principally reflects one company's downward revisions in 1981, subsequently reflected as upward revisions in 1982.
[b]Includes the effect of downward revisions of certain Alaskan gas reserves in 1985. Excluding such revisions, the majors' and 5-year averages would be 181 % and 161 % in 1985, respectively, and unchanged for the 5 years.

SOURCE" Arthur Andersen & Co., "Oil & Gas Reserves Disclosures 1981-85 Survey of 375 Public Companies, " 1986

These trends posed two concerns for the oil industry:

1. that lower future cash flows would mean less internal capital available to replace depleted reserves; and
2. that under existing price expectations, domestic exploration was proving to be a disappointing and costly means of replacing reserves.

These prospects led some companies to conclude that their limited exploration funds should be spent elsewhere—e.g., more intensive development drilling, more foreign exploration, or acquiring other companies or buying proven properties, or investing internally by buying back shares or boosting dividends.

Mergers and Acquisitions

The recent wave of mergers and acquisitions has reordered the domestic industry and thinned the ranks of majors and independents alike. The sheer size of some of the transactions involved and the controversial tactics of corporate raiders and target company managers have attracted headlines and raised concerns over the potentially adverse effects of "merger mania" on the domestic oil industry. Among the concerns were the effects on competition in the industry and the impacts on capital spending and exploration of the massive increase in merger-related debt.

During the period 1979 to 1986 over $75 billion was spent on the acquisition of publicly traded oil and gas companies. Table 36 lists some of the largest transactions involving oil producers.[28] Many oil companies concentrated on ac-

[28]This list is not inclusive and does not, for example include oil company acquisitions of coal companies and nonenergy companies during the same period. Among the more notable of these transactions were Standard 011's $2 billion purchase of Kennecott Corp. in 1982 and Gulf Oil Co.'s purchase of Kemmerer Coal Co., in 1981. Large-scale mergers in the mid-1980s have not been limited to 011 companies. Other multi-billion dollar transactions Include IBM's purchase of Rolm, Nestle's acquisition of Carnation, General Electric's takeover of RCA, and Capital Cities Communications' buyout of ABC. See *Impact of Corporate Takeovers, supra* note 2.

Table 36.—Mergers and Acquisitions in the U.S. Oil Industry

Year	Acquiring company	Target	Millions of dollars	Remarks
	Broken Hill Proprietary Ltd.	Energy Reserves Group	n.a	
	Houston Natural Gas	Florida Exploration	n.a	
	Mobil Oil Corp.	Vickers Energy	n.a	From Esmark
1979	Getty Oil Co.	Reserve Oil and Gas	620,0	
1979	Mobil Oil Corp.	General Crude Oil	792.0	From International Paper
1979	Shell Oil Corp.	Belridge Oil	3,660.0	
1980	Mobil Oil Corp	Trans Ocean Oil	715.0	
1980	The Sun Co., Inc.	Texas Pacific Oil & Gas	2,300.0	Properties acquisition only
1981	E.I. du Pent de Nemours & Co.	Conoco, Inc.	7,800.0	
1981	Occidental Petroleum Corp.	Crestmont Oil & Gas	82.3	
1981	Tenneco	Houston Oil & Minerals	1,650.0	Stock for stock
1982	Ashland Oil Co,	The Tresler Oil Co.	90.0	
1982	Ashland Oil Co	Scurlock Oil Co,	13.0	
1982	Occidental Petroleum Corp.	Cities Service	3,984.0	Cash plus stock
1982	U.S. Steel	Marathon Oil	5,950.0	
1983	Burlington Northern	El Paso Natural Gas	1,300.0	
1983	CSX Corp.	Texas Gas Resources	1,100.0	
1983	Diamond.	Shamrock Natomas.	1,500.0	
1983	Freeport McMoRan	Stone Exploration	112.0	
1983	Internorth (Enron)	Belco Petroleum	800.0	
1983	Phillips Petroleum	General American Oil	1,100.0	
1984	Chevron Corp.	Gulf Oil Corp.	13,300.0	
1984	Damson Oil	Dorchester Gas	400.0	
1984	Freeport McMoRan	Midlands Energy.	294.0	
1984	Mobil 011 Corp.	Superior Oil.	5,720.0	
1984	Phillips Petroleum	Aminoil USA,	1,600.0	From R.J. Reynolds
1984	Texaco, Inc.	Getty Oil.	10,200.0	
1984	The Sun Co , Inc.	Exeter Oil	75.0	
1984	U.S. Steel	Husky Oil USA	488,0	Asset acquisition
1985	BHP Petroleum Americas	Montsanto Oil	575.0	From Monsanto
1985	Burlington Northern	Southland Royalty		
1985	Coastal Corp.	American Natural Resources	2,400.0	
1985	Enron (Internorth)	Houston Natural Gas	2,200.0	
1985	Freeport McMoRan	Pel-Tex Oil	70.5	Assets acquisition only
1985	Midcon Corp.	United Energy Resources	1,200.0	
1985	Union Texas Petroleum	Union Texas Petroleum	n.a	LBO from Allied-Signal Corp.
1986	Freeport McMoRan	Petro-Lewis & American Royalty Trust:	440.0	jointly with Kidder Peabody
1986	Louisiana Land & Exploration Co.	Inexco Oil	470.0	
1986	Mesa Limited Partners	Pioneer Production Co.		Mesa Units and Debt
1986	Occidental Petroleum Corp.	Midcon Corp.	1,575.0	Cash for 53% plus Oxy stock
1986	U.S. Steel	Texas Oil and Gas	3,700.0	

n.a = not available

SOURCES: Oil and *Gas Journal,* Arthur Andersen & Co., and Congressional Research Service report, "Mergers and Acquisitions by Twenty Major Petroleum Companies January 1981 through February 1984."

quiring other companies in their core energy and chemical businesses. This pattern differs from the 1970s when many energy companies sought to diversify into other areas to cushion themselves from the uncertainties of world oil markets. For example, ARCO bought Anaconda Minerals, a major copper producer, and Mobil bought Montgomery Ward Department Stores. For **many major oil companies, the diversifications have** been disappointing and now, as part of restructuring programs, they are selling, spinning off, or liquidating these subsidiaries to return to their core energy and chemical businesses.

The largest of the mergers were in 1984 as Chevron bought Gulf, Mobil bought Superior, and Texaco acquired Getty. As the mergers and acquisitions trend continued in 1985 to 1986, the transactions frequently involved the absorption of a smaller ailing company into a larger, more financial sound company. (For example, Loui**siana Land & Exploration's acquisition of Inexco** Oil, and Freeport-McMoRan's bid for Petro-Lewis.) Major asset purchases have also continued. Some larger independents, such as Murphy Oil and Noble Affiliates, have told their shareholders that they are aggressively seeking acquisitions as a means of adding reserves at low cost. Takeovers and consolidations can be expected to continue as lower prices undercut the financial viability of many independent producers.

The recent mergers and acquisitions raised a number of major criticisms:

1. that massive merger-related borrowing by oil companies could crowd out other industries in capital markets;
2. that acquisitions would divert funds from exploration and development and other capital investment;
3. that the mergers eliminate viable competitors and contribute to the harmful consolidation of the industry;
4. that companies that acquired new reserves would be less likely to maintain an aggressive exploration program to replace production; and
5. that the massive new long-term debt assumed by some companies to successfully fend off hostile tender offers would seriously impair their ability to fund future exploration activities.

These concerns are countered with the arguments offered by those who strenuously defended all or some of the merger activities:

1. merger-related borrowing by oil companies was only a small portion of total loans outstanding and did not deprive other borrowers of credit;
2. in the past, oil industry merger-related loans were paid down within a few years out of asset sales and cash flow;
3. the funds paid for the acquired company did not disappear from the economy, but were returned to shareholders who could then reinvest them;
4. the merged firms will have to continue and even expand exploration programs to support the combined production levels;
5. investments in exploration are determined by expectations of future oil prices and profitability and are not influenced by the separate and independent considerations pertaining to mergers and acquisitions;
6. mergers and acquisitions are the marketplace's natural mechanisms for weeding out inefficient companies, moving assets to more efficient operators, and providing opportunities for new entrants into the industry and for expansion of existing firms;
7. newly merged firms are stronger competitors, both nationally and internationally; and finally
8. even unsuccessful takeovers contribute to the necessary restructuring of the industry because, to avert takeovers, target managements are forced to make changes in capital and operating structures that enhance shareholder values.

Reasons for Oil Industry Merger Mania

There have been many explanations offered in congressional hearings for the wave of ''merger mania" that struck the oil industry; some are summarized below. Many of the differences in viewpoint are not factual disputes, but represent contrasting values, policies, and theories. These reasons can be divided into two categories: those that relate to mergers and acquisitions in general, and those that reflect the special circumstances of the U.S. oil industry in the 1980s.

Among the general conditions resulting in merger and acquisition activity are:

- Mergers and acquisitions are the marketplace's natural remedies for inefficient corporate management and are the means for assets to flow to more productive use by stronger, more efficient companies. To the extent that the market value of oil companies is less than their book value, this reflects the stock market's correct assessment of their performance.
- Even a profitable company with competent managers can become a takeover target, if another company believes that the target's assets might be more valuable and profitable in its hands or if the target has some special expertise or capabilities that cannot easily be reproduced. The purchaser can thus afford to offer a premium over the market price to acquire the target to realize an increase in value of the assets under different management or as a means of entry into a new market or industry.

- Federal income tax benefits made corporate acquisitions attractive investments because of the deductibility of interest payments on merger-related debt, the stepped up basis in the acquired assets, and accelerated depreciation.
- Some recent takeover attempts were profitable for some companies and their financial backers, even if they did not succeed, for several reasons. To avert a threatened takeover the defending management sometimes brought the hostile offerors' shares at a substantial premium over the original purchase price. For example, Mesa Petroleum netted $214 million **on its** unsuccessful offer for Gulf, $4 l million from its offer for Phillips Petroleum, and an additional $83 million from its Unocal offer before the sale of another 14.6 million shares of Unocal it still held in 1986.[29] In other circumstances, the takeover threat caused the target management to initiate programs to return greater value to all shareholders, which the takeover group then shared. Once a takeover attempt was announced, the target company's stock often rose. Because securities laws only require public notification when an individual or company acquires more than a threshold percent, the takeover group could "accumulate" a substantial position in the target's stock on the open market before the announcement and then gain from selling the stock at a higher post-announcement price without ever completing the takeover bid.[30] Some critics contend that raiders and their investment bankers put companies "in play" by announcing a takeover bid without ever intending to complete the bid just to profit from "greenmail" offered by the target companies and from the runup in the stock's price.

Conditions in the oil industry in the 1980s also tended to favor mergers and acquisitions activity:

[29] Mesa petroleum, *Annual Report 1985*, p. 24.

[30] Takeover offers can be annou need "contingent on financing." The target and offeror stock prices often rise following the announcement and the offeror could later withdraw the offer without ever purchasing any tendered stock and still benefit from the increase in value of the shares already held. In addition to gains on the sale of stock, the backers of a takeover group often receive commitment tees, commissions and legal fees.

- The mergers and acquisitions could be seen as part of a larger trend in the restructuring of the oil industry. Mergers and acquisitions are symptomatic of the structure of a "mature" or "declining" industry. The consolidation reflects the expectation that the mature industry has only modest growth prospects and may have entered a period of inevitably declining production as remaining reserves are depleted.[31]
- The high debt levels and interest rates assumed by many independent oil companies to expand rapidly during the 1979-82 boom placed them in severe financial difficulty when oil prices began to decline. In order to survive, many of these businesses sought buyouts or mergers with other, stronger companies .32
- Some recent takeover attempts were profitable for some companies and their financial backers, even if they did not succeed, for several reasons. To avert a threatened takevalue as the underlying oil and gas reserves after oil prices tripled in 1979 to 1980. Oil company stocks sold for less than their per-share appraised value and for considerably less than the per-share breakup value. Several stocks sold for less than the per share book value of the company's assets.[33] This disparity made the companies attractive takeover targets. Corporate raiders, backed

[31] See Joint Economic Committee Study, *supra note 3.*

[32] See *testimony* of Jon Rex Jones for the Independent Petroleum Association of America in *Legislation Affecting Oil Merger Proposals, supra* note 1, at *321,*

[33] According to testimony given a House Comm ittee, i n March 1984 the stocks of five large integrated international oil companies, Exxon, Gulf, Mobil, Standard of California (SoCal) and Texaco were selling at an average 43.9 percent of their J.S.Herold appraised value. Of the group, Gulf, which was later acquired by SoCal, was selling at 57.2 percent of it's appraised value, the highest of the group. See testimony of Mark Gilman, in *Oil Industry Mergers:* Hearings on H.R. 5153, H.R. 5175, and H.R. 5452, Bills to Amend the Federal Trade Commission Act to Require a Study of Mergers, Acquisitions, and Joint Ventures in the Auto and 011 Industries, and for Other Purposes Before the Subcommittee on Fossil and Synthetic Fuels and the Subcommittee on Commerce, Transportation, and Tourism of the House Committee on Energy and Corn merce, 98th Cong., 2d sess. 250 (1984). (Hereafter, *Oil Industry Mergers.)* *See* also material submitted by T. Boone Pickens on comparative stock values and book values of major oil companies appended to testimony of Claude Brinegar of Unocal in *Impact of Corporate Takeovers, supra* note 2, at 82, 89-90. In his testimony Brinegar noted that the stocks of three companies that had previously restructured were selling at a lower percent of appraised value than companies that had not.

by aggressive institutional investors, Wall Street investment bankers and arbitrageurs, and often financed by "junk bonds, " put increasing pressure on oil companies to improve their return to investors or to become takeover targets.

- Acquisitions also were a more attractive investment alternative than some high risk exploration ventures for the huge revenues generated from oil production during the period of higher prices. Acquisitions also offered a quick and effective means of replacing reserves depleted through production. Some companies believed it was more financially attractive and less risky to "drill for oil on Wall Street" (by buying other companies for their proven reserves) than to continue to invest in risky exploration activities. Buying a company also offered the prospects of an immediate cash infusion from its producing reserves and from the sale of unwanted assets. In contrast, it is often years before there is any return from investments in long-term exploration and development projects.[34]

Effects of Mergers and Acquisitions

Mergers and acquisitions are claimed to be beneficial overall for stockholders and economy. Among the positive effects generally cited are: improved efficiency and lower costs for the merged entity, lower costs to consumers, and increased returns on investments in the stock of publicly held companies either from the premium over market value offered in the takeover, or from the correction in discounted stock prices.[35]

Another claimed benefit of mergers among major oil companies is that the larger combined companies will be stronger technically and financially and, thus, better able to sustain the increasing costs and risks of developing reserves in frontier areas and to compete with large foreign oil companies, often supported by their governments, in acquiring and developing concessions abroad.[36] Except for the gains realized on the sale of stock in the acquired companies, it is still too early to determine whether the recent mergers will in fact have these effects over the long term.

At the same time that mergers may prove beneficial to individual companies there remains the possibility that they could contribute to a net reduction in domestic petroleum production in the long term. The most obvious short-term results of the mergers have been an increased consolidation of the oil industry, a significant increase in long-term debt, and an apparent reduction in capital spending on exploration and production. For many industry observers, fewer companies and less exploration spending means fewer wells drilled, fewer reserves discovered, and eventually lower oil production.

OTA has reviewed the financial performance of 26 major and independent oil companies to assess the impacts of mergers and other restructuring changes in recent years. Table 37 presents aggregate information on these companies from their annual reports in 1983 to 1985. The companies are also subdivided into those that were involved in major corporate acquisitions (both successful and unsuccessful) in 1982 to 1986 and those that were not.[37] They include two groups, 14 major integrated oil companies, and 12 smaller independent oil companies. Measuring the impacts of mergers on these companies is complicated by the fact that most of the companies have ongoing restructuring programs that are intended to have some of the same results as some mergers. Nevertheless, OTA found some clear differences between companies involved in takeovers and other companies. There were also clear differences in expenditures for combined

[34]See responses of Mobil Oil Co. to Committee questions i n *Legislation Affecting Oil Merger Proposals, supra* note 1, at *638.*

[35]Efficiency gains are attributed to: i) increased economies of scale due to the larger size of the new entity; ii) marriage of complementary factors such as the combination of a reserves-rich firm with a reserves-poor company with extensive refining, marketing and petrochemical operations; iii) rationalization of production facilities by, for example, maintaining the most efficient facilities of the combined operations and eliminating others; iv) replacement of weak management; and v) economical technology transfer. See Testimony of Joseph j. Wright, Office of Management and Budget, in *Impact of Corporate Takeovers, supra* note *2,* at 610-612. See also statement of Morgan Stanley & Co., *Inc. in Legislation Affecting Merger Proposals, supra* note 1, at 516, and testimony of Professor Edward J. Mitchell, Graduate School of Business, University of Michigan in *Oil Industry Mergers, supra* note 13, at 359-60.

[36]Supplementary material submitted by Standard Oi l Co. Of California in *Legislation Affecting Oil Merger Proposals, supra* note 1, at *540.*

[37]For *Purposes* of this study ' ' major' acquisitions are those over *$400* million.

Table 37.—Financial Performance of a Group of Oil Companies, 1983-85 (millions of dollars, except percentages and ratios)

	Non-takeovers			All takeovers			Successful takeovers			Successful defenses			All companies in group		
	1985	1984	1983	1985	1984	1983	1985	984	1983	1985	1984	1983	1985	1984	1983
Large integrated oil companies:															
Revenues	209,525	214,809	211,148	200,717	203,830	179,027	173,276	176,546	153,072	27,441	27,284	25,955	410,242	418,639	390,175
Pretax net income	18,614	24,448	23,371	16,802	16,212	14,770	14,186	12,855	11,352	2,616	3,357	3,418	35,416	40,660	38,141
Earnings	10,012	12,582	12,668	4,654	5,429	6,183	3,911	3,919	4,836	743	1,510	1,347	14,666	18,011	18,851
Cash flow	30,585	31,242	28,724	21,633	19,991	16,441	17,668	15,730	12,626	3,965	4,261	3,815	52,218	51,233	45,165
Internal cash flow	32,097	34,947	33,319	29,704	26,973	21,319	24,755	21,428	15,983	4,949	5,545	5,336	61,801	61,920	54,638
Total assets	192,855	183,174	180,741	159,390	159,827	126,397	134,548	132,669	104,081	24,842	27,158	22,316	352,245	343,001	307,138
Total shareholders equity	79,529	83,676	75,188	59,864	68,794	58,032	56,590	56,476	46,703	3,274	12,318	11,329	139,393	152,470	133,220
Total long-term debt	27,811	24,941	15,489	37,105	43,348	15,149	28,475	39,387	11,767	8,630	3,961	3,382	64,916	68,289	30,638
New long-term debt	6,802	3,508	3,689	15,947	27,990	4,012	5,565	26,741	3,478	10,382	1,249	534	22,749	31,498	7,701
Total debt/total capitalization	0.26	0.23	0.17	0.38	0.39	0.21	0.33	0.41	0.20	0.72	0.24	0.23	0.32	0.31	0.19
Debt/equity	0.35	0.30	0.21	0.62	0.63	0.26	0.50	0.70	0.25	2.64	0.32	0.30	0.47	0.45	0.23
Where the money went:															
Interest expense	3,428	3,003	3,069	5,824	4,475	2,089	4,504	4,029	1,719	1,320	446	370	9,252	7,478	5,158
Percent of earnings before interest and taxes	16	11	12	26	22	12	24	24	13	34	12	10	21	16	12
Dividends	6,291	6,332	6,020	3,898	3,774	3,665	3,187	3,238	3,154	711	536	511	10,189	0,106	9,385
Percent of cash flow from continuing operations	21	20	21	18	19	22	18	21	25	18	13	13	20	20	21
Repurchase of stock	7,322	5,379	874	11,316	1,533	253	2,166	1,533	253	9,150	0	0	18,638	6,912	1,127
Percent of internal cash flow	23	15	3	38	6	1	9	7	2	185	0	0	30	11	2
Total capital spending	25,899	23,901	20,622	12,686	15,322	3,182	0,099	12,009	10,461	2,587	3,313	2,721	38,585	39,223	33,804
Percent of internal cash flow	81	68	62	43	57	62	41	56	65	52	60	51	62	63	62
Percent of change	8	16	—	−17	16	—	−16	15	—	−22	22	—	−2	16	—
Capital spending for E&P (mostly U.S.)	16,852	16,333	13,487	7,542	8,379	7,134	5,776	6,470	5,403	1,766	1,909	1,731	24,394	24,712	20,621
Percent of internal cash flow	53	47	40	25	31	33	23	30	34	36	34	32	39	40	38
Percent of change	3	21	—	−10	17	—	−11	20	—	−7	10	—	−1	20	—
Repayment of long-term debt	4,195	3,527	4,267	18,522	4,725	4,054	6,135	4,198	3,869	2,387	527	185	22,717	8,252	8,321
Percent of internal cash flow	13	10	13	62	18	19	65	20	24	48	10	3	37	13	15

(continued on next page)

Table 37.—Financial Performance of a Group of Oil Companies, 1983-85 (millions of dollars, except percentages and ratios)—Continued

	Non-takeovers			akeovers			Total for group		
	985	1984	1983	1985	1984	1983	1985	1984	1983
Smaller independent oil companies:									
Revenues	8,995	9,459	8,910	9,435	8,663	8,164	18,430	18,122	17,074
Pretax net income	1,159	1,676	1,714	428	993	707	1,587	2,669	2,420
Earnings	325	768	792	432	561	407	757	1,329	1,199
Cash flow	2,780	2,647	2,345	1,314	1,178	1,196	4,094	3,825	3,540
Internal cash flow	2,297	2,959	2,847	1,180	1,468	1,357	3,477	4,427	4,204
Total assets	15,482	5,259	14,458	13,016	10,735	8,790	28,498	25,994	23,248
Total shareholders equity	5,628	5,838	5,841	2,325	2,601	2,444	7,954	8,439	8,285
Total long-term debt	3,965	3,599	2,852	5,715	4,144	2,862	9,680	7,743	5,714
New long-term debt	1,151	470	274	2,355	2,537	1,075	3,506	3,007	1,349
Total debt/total capitalization	0.41	0.38	0.35	0.71	0.61	0.54	0.55	0.48	0.42
Debt/equity	0.70	0.62	0.49	2.46	1.59	1.17	1.22	0.92	0.69
Where the money went:									
Interest expense	405	392	393	630	358	222	1,036	750	615
Percent of earnings before interest and taxes	26	19	19	60	27	24	39	22	20
Dividends	624	326	269	130	123	117	754	449	386
Percent of cash flow from continuing operations	22	12	11	10	10	10	18	12	11
Repurchase of stock	289	287	15	261	695	298	550	982	313
Percent of internal cash flow	13	10	1	22	47	22	16	22	7
Total capital spending	2,495	2,279	1,831	907	690	851	3,402	2,968	2,681
Percent of internal cash flow	109	77	64	77	47	63	98	67	64
Percent of change	9	24	—	32	−19	—	15	11	—
Capital spending for E&P (mostly U.S.)	1,787	1,581	1,461	512	492	639	2,298	2,073	2,100
Percent of internal cash flow	78	53	51	43	33	47	66	47	50
Percent of change	13	8	—	4	−23	—	11	−1	—
Repayment of long-term debt	813	347	371	1,296	786	737	2,109	1,133	1,108
Percent of internal cash flow	35	12	13	110	54	54	61	26	26

companies before and after the mergers. For example, as discussed later, OTA found that the large post-merger firms spent a smaller portion of available cash flow for exploration and other capital expenditures and devoted a higher level of cash flow for debt reduction than did firms that were not involved in acquisitions.

Several of the large company mergers have resulted in a retrenchment and contraction of resulting entities into something significantly less than the sum of the combined pre-merger companies with fewer employees, fewer total reserves, and less total production than before. While some downsizing reflects efficiency gains in the reduction of redundant overhead, other shrinkages are the results of asset sales and additional cost-cutting so that cash can be redirected to paying down debt.

There has also been a redistribution of oil and gas assets through post-merger asset sales. This may result in properties being transferred to new owners who can make more efficient and profitable use of them. Some major oil companies are selling off less profitable wells in smaller producing oilfields with high overhead levels. These properties could be attractive to other companies with extensive holdings in the same field that could benefit from economies of scale, or to independent producing companies with lower overhead. Some new owners have made or announced planned investments to expand production in their newly acquired properties. These asset sales are also coming at a time when the price for proven properties is much lower than it has been, so that companies buying reserves can often do so for much less than average finding costs.

Mergers and the Consolidation of the Oil Industry

The new combinations arising from the recent mergers reordered the rankings of the major oil companies. Table 38 shows the top 20 petroleum companies ranked by assets, liquids reserves, and liquids production in 1980 and 1985. By 1985, 9 of the top 30 oil companies in 1980 had been acquired. The primary changes in the rankings are the disappearance of some "second tier" independent integrated companies and the elevation of smaller companies into the ranks of the majors. As shown in table 39, the relative holdings of the top 8 firms have increased through the Gulf-Chevron merger and the absorption of several of the larger independents, Getty, Marathon, and Superior.[38] At the same time the concentration levels of the largest 20 oil companies have declined relative to the rest of the industry.

Consolidation has also been significant among the independents. Mergers and acquisitions, as well as bankruptcies, dissolutions, and liquidations have also contributed to a thinning and consolidation in the ranks of the independents. According to the Oil *and Gas Journal* annual reports on the 400 largest publicly held oil and gas producers, the year-end value of assets needed to place on its list dropped from $2.37 million in 1983 to $276,000 in 1984, to $179,000 in 1985.[39] Among the smaller public and private independents, there has also been a severe shrinkage which has been estimated at about 25 to 30 percent of the independent exploration and production companies. While detailed information on the disappearance of the independents is not readily available, the estimated number of independents, as presented in testimony on behalf of the Independent Petroleum Association of America (IPAA), declined from over 15,000 in 1984 to about 12,000 in mid-1986.[40] Some believe that the majors could be a more dominant influence in domestic exploration and production than before 1980 as a result of the consolidation among the larger companies and the disappearance of so many independent operators.

Some industry observers believe that the contraction of the majors could create more opportunities for independents in some niches. With smaller exploration staffs and less money to spend on drilling, the majors may be willing to do more

[38] The table does not fully reflect the acquisitions announced in 1986; when these transactions are taken into account they will further reflect this trend.

[39] 82 *Oil & Gas Journal* 103, Sept. 10, 1984; 83 *Oil & Gas Journal* 89, Sept. 10, 1985; 84 *Oil & Gas Journal* 55, Sept. 8, 1986.

[40] See testimony of Raymond H. Hefner, for the IPAA in *Hearings on the Domestic and International Petroleum* Situation and the *Implications of Fees on Imported Oil Before the Senate Comm. on Energy and Natural Resources,* 99th Cong., 2d sess. 196, 225 (1986). See also, testimony of Jon Rex Jones for the IPAA in *Legislation Affecting Oil Merger Proposals, supra* note 1, at 315.

Table 38.–Comparison of 20 Largest U.S. Oil Companies, 1980 and 1985

Top 20, 1985 Rank company	Total assets ($ billions)	Top 20, 1980 Rank company	Total assets ($ billions)
1 Exxon Corp.	69.16	1 Exxon Corp.	56.58
2 Mobil Corp.	41.75	2 Mobil Corp.	32.71
3 Chevron Corp.	38.90	3 Texaco, Inc.	26.43
4 Texaco, Inc.	37.70	4 Standard of California (Chevron)	22.16
5 Shell 0il Co.	26.53	5 Standard Oil (Indiana)	20.17
6 Amoco Corp.	25.20	6 Gulf Oil Corp.	18.64
7 Tenneco, Inc.	20.44	7 Shell Oil Co..	17.62
8 Atlantic Richfield Co.	20.28	8 Atlantic Richfield Co.	16.60
9 Standard Oil Co.	18.33	9 Tenneco, Inc.	13.85
IO Phillips Petroleum Co.	14.05	10 Standard Oil (Ohio)	12.08
11 Sun Co., Inc.	12.92	11 Conoco Corp....	11.04
12 Occidental Petroleum Corp.	11.59	12 Sun Co., Inc.	10.96
13 Unocal Corp.	10.80	13 Phillips Petroleum Co.	9.84
14 Marathon Oil Co.	10.07	14 Getty Oil	8.27
15 Conoco Corp.	9.90	15 Union Oil of California.	6.77
16 Enron Corp.	9.89	16 Occidental Petroleum Corp.	6.63
17 Coastal Corp.	8.29	17 Amerada Hess Corp.	5.90
18 Amerada Hess Corp.	6.22	18 Cities Service.	5.36
19 Columbia Gas System, Inc.	5.84	19 Marathon Oil Co.	5.04
20 Midcon Corp.	5.81	20 Coastal Corp.	4.11

NOTE: Excludes mergers after Dec. 31, 1985

SOURCES *Oil and Gas Journal,* Sept *5, 1988, Fortune Magazine, "500* Largest Industrial Corporations," 1980 data, published May 4, 1981, at 322

Table 39.—Comparison of Historical Concentration in the U.S. Oil Industry (percent of U.S. total)

Concentration ratio-U.S. net crude oil, condensate, and natural gas liquids production

	1955	1960	1965	1970	1975	1980	1983	1984	1985
4-Firm	18.1	20.8	23.9	26.3	26.0	25.3	25.0	26.1	26.20/o
8-Firm	30.3	33.5	38.5	41.7	41.2	40.8	38.4	44.5	43.6
15-Firm	41.0	44.2	50.3	56.9	57.0	56.1	53.5	56.4	53.2
20-Firm	46.3	49.1	55.0	61.1	61.2	60.6	57.6	59.4	55,8

Concentration ratio-U.S. liquids reserves

	1975	1980	1983	1984	1985
4-Firm	36.3	31.1	29.0	29.6	29.10/o
8-Firm	55.6	46.3	43.2	48.6	41.7
15-Firm	70.4	59.5	56.1	59.1	47.3
20-Firm	74.5	62.7	59.4	61.2	58.9

SOURCE: Office of Technology Assessment from American Petroleum Institute, Market Shares and Individual Company Data for U.S. Energy Markets 1950-84, Discussion Paper #O14R, Oct. 1985; 1985 Data from Oil and Gas Journal and Independent Petroleum Association of America, Petroleum Statistics 1985.

farmouts with independents and may even be willing to share some of the costs rather than merely contributing drilling rights.[41] Moreover, if the merged companies cut back their unproven property acquisitions and exploration efforts, independents may be more successful in obtaining some of the better prospects with reduced competition from the majors.

There has been concern expressed that the new combinations will diminish competition within the domestic industry. But, by several commonly used antitrust enforcement measures, the oil and gas industry remains competitive. Concentration levels in liquids production and

[41] Remarks of Ray Hunt, at SMU-ISM conference on Lower World 011 Prices in Dallas, September 1986.

reserves are still within historical levels (see table 39). The Federal Trade Commission has characterized the oil and gas production industry as "not highly concentrated."[42] Applying the current antitrust enforcement guidelines used by the Department of Justice and Federal Trade Commission to the market for crude oil, no merger between competing oil companies is likely to be challenged based on its effects in the overall crude market. In several large mergers, the Federal Government found significant downstream antitrust problems and ordered divestitures of certain downstream marketing and refining operations before approving the mergers.

In testimony before Congress, several witnesses questioned the adequacy of the standard measures for assessing mergers among large oil companies. Concentration ratios, HHI and other indices are primarily concerned with measuring the effects on market share of horizontal mergers (combinations between competing companies), and do not adequately reflect the true impacts on competition of mergers in the vertically integrated oil industry. For example, it was noted that the six largest oil companies could combine into a single giant company without exceeding the HHI indices triggering enforcement review.[43] Moreover, they noted, traditional antitrust and competition considerations were not the only areas of economic or social concern raised by the mergers.

[42]See testimony of Timothy J. Muris, Director, Bureau of Competition, Federal Trade Commission in *Legislation Affecting Oil Merger Proposals, supra* note 1, at 71, citing a 1982 FTC study on concentration in the 011 industry. See also, American Petroleum Institute, *Market Shares and Individual Company Data for U.S. Energy Markets: 1950- 1984*, Discussion Paper, October 1985. Estimates of 4-firm and 8-firm concentration ratios in the oil industry have been fairly steady, varying only a few percentage points either way since 1970. The 1982 Department of justice Merger Guidelines use numerical standards to ascertain whether a proposed merger between competing companies may tend to affect competition adversely—the Herfindahl-Hirschman n index or HH 1. The government is most likely to challenge a proposed merger if the post-merger H H I index is above 1,000 or if it increases the post-merger HHI is increased by more than 100 points to above the 1800 level. "The HHI measured in terms of U.S. production is only about 270 and in terms of U.S. crude oil reserves is approximately 329. All of these values are well below the 1,000 HHI level that normally triggers potential antitrust concern with a merger between competitors. " Testimony of Timothy J. Murris in *Oil Industry Mergers, supra* note 13 at 234-237.

[43]*Oil Industry Mergers, supra* note 13, at 204.

Increase in Long-Term Debt

The wave of acquisitions and anti-takeover defensive tactics added substantially higher **levels of debt** for the oil industry as a whole, as well as for individual companies. The Department of Energy found an increase in debt equity ratio among the Financial Reporting System (FRS) companies from 34.8 to 49.5 percent in 1984 alone, with much of this increase attributable to the effects of the Chevron-Gulf, Texaco-Getty, and Mobil-Superior takeovers.[44] OTA's review of a group of oil companies also shows higher debt levels for most merged companies (see table 37). Total long-term debt of the companies studied **more than doubled between 1983** and 1985. The largest increases were by firms involved in takeovers; their debt levels nearly tripled in 1983 to 1984 but repayments in 1985 lowered their overall long-term debt to 2½ times the 1983 levels. The heavier debt loads, at least in the short term, have been accompanied by lower total expenditures by the combined companies on exploration and capital investment in 1985 than in 1984. Among the companies not involved in takeovers, new long-term debt was used to retire prior debt at higher interest rates, to repurchase shares, to buy assets, and to provide additional capital for investment. The highest debt to debt plus equity ratios, a common measure of debt load or leverage, was shown by the two companies that successfully averted hostile takeover offers—increasing from 0.23: 1 in 1983 to 0.72:1 in 1985.

[44]U.S. Department of Energy, Energy Information Adm in istration, *Performance Profiles of Major Energy Producers 1984, 20-21 (1986).* The FRS companies are a group of companies that are required to file detailed annual reports. The FRS companies were selected from the top 50 publicly owned domestic crude oil producers in 1976 who had at least 1 percent of either the production or reserves of oil, gas, coal or uranium, or 1 percent of refining capacity or or petroleum product sales. In 1984 the FRS group included: Amerada Hess Corp.; American Petrofina, Inc.; Ashland Oil, Inc.; Atlantic Richfield Co.; Burlington Northern, Inc; Chevron Corp.; Cities Service Oil Co.; Coastal Corp.; El. du Pent de Nemours & Co.; Exxon Corp.; Getty 011 Co.; Gulf Oil Corp.; Kerr-McGee Corp.; Mobil Oil Corp.; Occidental Petroleum Corp.; Phillips Petroleum Co.; Shell Oil Co.; Amoco Corp.; Standard Oil Co.; Sun Company, Inc.; Superior Oil Co.; Tenneco, Inc.; *Texaco, Inc.;* Unocal Corp.; Union Pacific Corp.; and United States Steel Corp. Four acquired companies, Cities Service, Gulf, Getty, and Superior, all filed separate FRS reports for 1984 because the mergers were not fully complete.

Many of the corporate acquisitions followed intense, and sometimes bitter, battles for corporate control. The impacts on corporate finances of defensive tactics adopted to fend off unwanted or "hostile" takeover offers raised concerns about the targets' future ability to fund exploration activities. In several successful takeover defenses, the target companies averted the takeover by buying the offerors' shares at a premium. In others, the target merged with a friendly "white knight", which often outbid the original offerors. The defending company was left with much higher debt. The unsuccessful offeror was left with a sizable gain on the stock transaction. Results such as this have led some raiders and other critics to contend that the target managements were motivated more by concern over protecting their own jobs than **in advancing the shareholders interests.**

An increase in long-term corporate debt is not by itself reflective of a weakened financial position. Debt and equity are the two principal means of raising capital for acquisitions and for capital spending. Increased debt has some risks, however. Debt brings with it a requirement to pay interest that, unlike dividends, generally cannot be deferred. High debt levels among oil companies raise two concerns: reduced flexibility in deciding how to spend its available cash flow; and reduced commitments to exploration and production as assets are sold and capital expenditures are cut to pay off debt.[45]

Effects on Exploration

The pattern of reduced exploration expenditures following recent mergers tends to contradict some of the earlier studies and examples cited in testimony in 1984 at the height of the mergers. Following the acquisitions of Marathon by U.S. Steel, Conoco by Du Pent, and Belridge by Shell, exploration expenditures were reported to have increased. But these results predated the more recent round of mergers and both the U.S. Steel and Du Pent acquisitions involved essentially new entrants into the oil business that operated their purchases as separate subsidiaries. More recent mergers have involved the disappearance by absorption of one energy company into another and the overall contraction of the combined entity, with lower production levels, reserves, and exploration expenditures.

During the debate over the effects of mergers and acquisitions in the oil industry, many of the representatives of acquiring companies, their investment bankers, and their defenders strongly denied that exploration efforts would be reduced.[46] Some company executives even suggested that exploration could be expanded because of efficiency gains and the stronger cash flows and asset bases of the merged companies. However, others inside and outside the industry argued as strongly that exploration would be cut because the newly purchased reserves reduced the incentive to look for more oil and repayment of the new long-term debt would **divert** cash flow that otherwise might be used for E&D.

The available evidence strongly suggests that the short-term results of the merger activity for the U.S. oil industry as a whole are reduced spending on exploration, fewer wells drilled, and less R&D than there was before the mergers and, arguably, than there might have been had these firms continued as separate entities. The amount of this change is not possible to quantify, but is probably much less than the losses attributable to the decline in prices. The merger-related expenditure declines are probably less than those caused by low prices because the 1986 spending cuts by all companies tended to be as large or larger than the 1985 cuts by merged companies. The fact that merged companies took cuts in E&P and capital expenditures in 1985, while others were still spending at previous levels or higher, suggests that the mergers have significantly decreased exploration expenditures below levels that might have been maintained by independent entities. If, for example, Gulf, Superior,

[45] Total long-term debt over 40 percent of a companies total capitalization (Total long-term debt, plus total equity) is considered high, but not unmanageable, however debt levels of 70 percent of capitalization or more are a matter for concern.

[46] For examples, see: Supplementary material submitted by Standard Oil Company of California in *Legislation Affecting Oil Merger Proposals, supra* note 1, at 540; response of Chevron U.S.A. to Committee questions, *id.* at 539; statement of Morgan Stanley & Co., Inc., *id.* at 516; and material submitted by the Department of the Interior, *id.* at 529. See also, Testimony of Joseph J. Wright, Office of Management and Budget, in *Impact of Corporate Takeovers, supra* note 2, at 610-612; and testimony of Professor Edward J. Mitchell, Graduate School of Business, University of Michigan in *Oil Industry Mergers, supra* note 13, at 359-60.

Getty, and Cities Service had remained separate and continued their active exploration programs and if these programs were cut at the industry average, the separate exploration expenditures added to the baseline expenditures for Chevron, Mobil, Texaco, and Occidental, respectively, would likely exceed the totals for the merged entities.

The merged companies typically cut combined capital spending significantly in 1984 to 1985, while other large oil companies were maintaining or increasing their investments. This pattern is also seen in other surveys of U.S. exploration and development expenditures shown **in table 40** for 1983 to 1985. Table 41 shows a similar pattern in different, but comparable data on domestic exploration expenditures in 1986 to 1987. When oil prices fell in 1986, the merged companies reduced exploration budgets that were already constricted, and the share of their cash flow directed at debt reduction is undoubtedly much higher than was anticipated when the mergers occurred.

There are others who maintain that it is purely coincidental that exploration expenditures of some combined companies were cut substantially after the mergers. In their view the reasons for the cuts were related solely to the anticipated future oil prices and the quality of the available exploration prospects. There are of course other fac-

Table 40.—Capital and Exploration Expenditures for Selected Oil Companies 1983-1985 (thousands of dollars)

	1985 capital and exploration spending	Percent change 1984-85	1984 capital and exploration spending	Percent change 1983-84	1983 capital and exploration spending
Exxon Corp	10,339,000	6.0	**9,755,000**	8 4	**9,000,000**
Amoco Corp	5,306,000	14.6	**4,630,000**	13,2	**4,091,000**
Shell 011 Co	4,080,000	3.9	**3,927,000**	37,8	**2,850,000**
Mobil Corp	3,513,000	– 7,7	**3,806,000**	–12 4	**3,330,000**
Superior 011	—	—	**—**	—	1,016,855
Combined	3,513,000	–7 7	**3,806,000**	–12 4	4,346,855
Texaco, Inc	2,824,000	–24 6	**3,744,000**	–26 O	3.833,000
Getty 011	—	—	**—**	—	1,223,319
Combined	2,824,000	–24 6	**3,744,000**	– 26.0	5,056,319
Atlantic Richfield Co	3,595,000	10,4	**3,257,000**	–2.9	3,355,384
Chevron Corp	4.035,000	– 15.7	**4,786,000**	– 18.0	3,067,000
Gulf 011	—	.	**—**	—	2,770,000
Combined	4,035,000	– 15,7	**4,786,000**	– 18,0	5,837,000
Sun Co Inc.	1,748,000	–26,5	**2,377,000**	83.7	1,294,000
Standard 011 Co.	4,277,000	83.6	**2,329,000**	1.3	2,298,000
Unocal Corp .	1,847,400	–5.0	**1,944,800**	11.1	1,751,000
Tenneco, Inc	1,719,000	– 1,7	**1,748,000**	8.6	1,609,000
Conoco Corp.	1,402,000	1.1	**1,387,000**	–20.5	1,744,700
Phillips Petroleum .,	1,060,000	–23.6	**1,387,000**	21,6	1,141,000
Amerada Hess Corp. ...	929,000	– 16,5	**1,112,161**	53.1	726,365
Occidental Petroleum Corp. .,	1,151,700	5.5	**1,091,240**	14.7	951,019
MidCon Corp.	354,869	● 8.2	**327,951**	8.9	301,229
Combined[a]	—	.	**—**	—	
Marathon Oil Co. . .	1,165,000	60.2	**727,000**	–25.0	969,000
Texas Oil & Gas Corp. . . .	739,400	–3.8	**768,679**	16,1	662,332
Internorth, Inc.	591,200	–8.8	**648,548**	155,2	254,152
Houston Natural Gas Corp. .,	**–**	—	**413,652**	33.0	310,971
Combined	**591,200**	–44,3	**1,062,200**	88.0	565,123
Diamond Shamrock Corp	**679,900**	7,0	**635,500**	36.1	466,853
Pacific Lighting Corp. .,	**527,114**	–7, 1	**567,335**	– 10.8	636,013
Coastal Corp.	**341,300**	122	**153,542**	34.8	113,893
American Natural Resources	**—**	—	**404,600**	34.4	301,100
Combined .,	**341.300**	–38.9	**558,142**	34.5	414,993

[a]Merger completed m early 1986

SOURCE OTA from 011 & Gas Journal and company annual reports

Table 41.—Changes in Planned Expenditures on U.S. Exploration and Production

	Actual 1985	June '86 budget	Percent change 1985-86	Actual 1986 est.	Jan. '87 budget	Percent change 1986-87
***Major oil* companies:**						
Amerada Hess Corp.	310	120	–61	95	75	–21
Amoco Corp.	3,170	1,650	–48	1,300	1,300	0
Atlantic Richfield Co.	2,300	1,035	–55	1,000	750	–25
Chevron Corp.[a] . .	1,800	1,200	–33	1,050	975	–7
El. du Pent de Nemours[a]	700	420	–40	500	550	10
Exxon Corp. .	4,700	3,050	–35	2,700	2,565	–5
Kerr-McGee . .	140	75	–46	75	70	–7
Mobil Corp.[a] . .	1,460	1,020	–30	1,020	1,020	0
Occidental Petroleum Corp.[a]	375	260	–31	260	235	–10
Pennzoil . ,	270	175	–35	140	120	–14
Phillips Petroleum Co[a]	455	335	–26	200	240	20
Shell Oil Co. .	1,800	1,350	–25	1,645	1,520	–8
Standard	1,700	1,000	–41	1,250	1,150	–8
Sun Co., Inc.	820	625	–24	430	430	0
Tenneco, Inc.	565	240	–58	310	235	–24
Texaco, Inc.[a]	1,670	1,100	–34	1,000	900	–10
Union Pacific	400	200	–50	195	185	–5
USX Corp.[a] . .	1,255	725	–42	560	480	–14
Unocal Corp.[a]	945	680	–28	600	640	7
Total majors	24,835	15,260	–39	14,330	13,440	–6
Selected independents:						
Apache.	120	80	–33	65	25	–62
Burlington Northern[a]	430	95	–78	100	100	0
Diamond Shamrock[a]	190	90	–53	105	130	24
Enron[a]	200	100	–50	100	91	–9
Enserch	250	140	–44	158	103	–35
Freeport-McMoRan[a]	122	55	–55	55	52	–5
Louisiana Land[a]. ...	260	155	–40	155	147	–5
Mitchell Energy ...	130	89	–32	65	65	0
Murphy .	113	60	–47	50	50	0
Pogo Producing . .	115	70	–39	65	40	–38
Santa Fe Southern[a]	195	145	–26	100	95	–5
Transco Exploration	280	125	–55	125	120	–4
Total independents.	2,405	1,204	**–50**	**1,143**	**1,018**	**–11**

[a]Companies involved in major takeovers 1982-86

SOURCES OTA from Oil & *Gas Journal* July 21, 1986, and Jan 19. 1987

tors that contributed to lower exploration expenditures in recent years, such as lower property acquisition costs because of reduced offerings of Federal offshore leases and lower bonuses, cost deflation in drilling and services, and deferrals of major projects because of price uncertainty. These factors affected both merged and non merged firms alike, however.

Oil production may actually increase if the purchaser can exploit the acquired reserves more efficiently. The classic example of this was Shell Oil Co.'s acquisition of Belridge Oil in 1979. Following the merger, Shell invested in enhanced recovery to expand heavy oil production from Belridge's California reserves. More recently, a good geographic "fit" of acquiring and acquired companies was cited as an advantage in the Phillips' takeovers of General American Oil and Aminoil, and in Louisiana Land & Exploration Co.'s purchase of Inexco Oil. These transactions involved complementary reserves holdings in areas where the purchasers were already active and allowed expansion into other areas where they were not represented.

Some major acquisitions may have been motivated primarily by reserves replacement, rather than as a means of corporate expansion. Several companies that bought other firms for their reserves had not been particularly successful in replacing their reserves through exploration.[47] This motivation is suggested by the shrinkage of the post-merger companies as many unwanted producing properties and operations are sold or abandoned. The acquiring company may be successful in maintaining its production level in the future out of its purchased reserves, but it may support a production level that is less than the combined companies before the acquisition. Cumulatively, overall domestic production could drop because of reduced total spending on exploration.

It has been argued that mergers need not result in reduced exploration and fewer reserves added. For example, a merger might create a new entity that is more efficient and successful at finding oil than its predecessors. Moreover, the combined firm would still face the need to replace the reserves lost through production (assuming it maintains the same production level after the merger) and would still be subject to requirements to drill many of its leases or lose them. The combination might lead to improved economies of scale by eliminating or reducing duplicative overhead and nondevelopment-related expenditures allowing more productive use of the combined financial resources and technical people.[48] The Department of the Interior has suggested that even if the merged company only conducted the same amount of exploration as before, it could combine information on geology, and geophysics of exploration prospects and select the best drilling sites from a larger menu and it might actually improve its exploration results with less overall spending on exploration and fewer holes drilled than might have been spent by the firms separately.[49] (This suggested result is questionable, however, since high grading would not necessarily increase the amount of reserves found, particularly if the acquired company was no more successful at finding oil than the acquiring company or if the exploration staff responsible for the reserves position of the acquired company is laid off or leaves.)

Others doubt that there are any added efficiencies in oil exploration to be gained through the mergers among large oil companies. Historically, the range of finding costs posted by both first and second tier major oil companies have been similar. The biggest companies did not necessarily have the lowest finding costs. Moreover, most of the anticipated savings would come from cutting staff, which may lead to long-term inefficiencies in exploration from the lack of experienced technical people.[50]

it is too soon to tell whether the mergers will mean a net increase or decrease in exploration and production in the long term. Several merged companies, e.g., Chevron and Mobil, have made substantial efforts to pay down debt even with lower oil prices. In a few years, they maybe ready to reallocate resources to exploration and research from a stronger financial and resource position.

In the longer term, even at lower oil prices, many of the larger merged companies will again have cash available that could be used for E&P after reducing their long-term debt. It will then become more apparent whether the added debt burden, asset sales, and restricted exploration activities assumed to undertake the merger will have produced a sounder, more efficient enterprise better suited to an era of uncertain oil prices. Table 41 shows preliminary 1987 exploration budgets for some firms, and it is notable that several of the merged firms are slightly increasing their exploration budgets.

Other Restructuring Activities

Oil companies have adopted a variety of restructuring strategies which they believe will help them to compete in the current era of volatile energy prices. Mergers and acquisitions have been perhaps the most public aspect of the restructuring, but they have been only part of a range of industry responses to changing conditions.

[47] See Donald F. Textor, Todd Bergman, and Cristina Tiscareno, "Finding Costs and Reserves Replacements Results 1979-1 985," Goldman Sachs Investment Research, Apr. 2, 1986.

[48] See, for example, response of Chevron U.S. A. to Committee questions in *Legislation Affecting Oil Merger Proposals, supra* note 1, at 539.

[49] Additional material submitted by the Department Of the Interior, *Legislation Affecting Oil Merger Proposals, supra* note 1, at 529.

[50] See, for exam Pie, the testimony of Howard W. Pifer, III, Managing Director, Putnam, Hayes & Bartlett, Inc., in *Oil Industry Mergers, supra* note 13, at 211.

Segmentation and "Dis-integration"

Changes in the world oil industry following the OPEC price shocks of the 1970s have contributed to the modification of the traditional integrated structure of some major companies. Maintenance of a secure source of crude supply is no longer a priority for many integrated companies because of: 1) current world overcapacity in oil production; 2) a greater diversity of sources for crude oil with decreased reliance on mideast OPEC oil; and 3) the widely shared expectation that oil demand (and hence sales) will grow only modestly through the end of the century.

The process of buying and selling of crude oil has also changed. Oil prices now can fluctuate much more rapidly than before. The traditional long-term contracts for crude, which used to account for 90 percent of U.S. supplies, have largely been abandoned, and in 1986 up to ***90*** percent of supplies from outside the United States were obtained on the spot market or at spot-market-related prices. Netback arrangements with foreign producers are a part of this trend.[51] Many companies have turned to options trading to moderate the risks of volatile oil prices.

Increasingly, segments of the oil industry are being separated vertically and operationally. Some integrated companies no longer depend on their own reserves to supply their refining and marketing operations.[52] Downstream operations are frequently seen as separate from upstream exploration and production activities. The downstream activities are now treated as independent and important profit centers rather than as an outlet for a company's crude. In the early 1980s, this shift led to the closing of many company-owned retail outlets and a net reduction in domestic refining capacity as refineries were upgraded and outmoded facilities were closed. Some companies have begun to redeploy their resources to their most profitable segments functionally and geographically instead of maintaining an integrated nationwide operation from exploration and production to shipping, refining, distributing, and marketing. For example, Ashland Oil sold many of its producing oil properties and relies more heavily on crude purchases to supply its refineries. Arco has pulled out of the retail oil market in the northeast. The cost-cutting and upgrading in refining operations as part of the early restructuring of downstream operations appear to have benefited some companies during the price plunge, with higher profit margins in refining helping to offset upstream losses.

According to some industry analysts, the growing segregation of upstream and downstream activities has contributed to a decline in the proportion of production revenues "plowed back" into acquiring and developing unproven properties. The 60 percent "plowback" in 1985 was the lowest in at least 5 years (see table 42). As noted earlier, a primary factor driving these changes has been the mediocre result of much of the E&D activity of the last 10 years reflected in the extremely high finding costs reported by much of the industry and the serious disappointments in exploration on the frontiers.

Cost-Cutting

Many restructuring programs were announced as efforts to cut costs and conserve capital and cash flow in anticipation of a prolonged period of low oil prices and sluggish demand. Although these changes were announced in early to mid-1985, most companies underestimated how sharply, and quickly, oil prices would actually fall in 1986 so that these programs were not fully in place to offset potential losses.

[51] Netback contracts are an arrangement between the seller of crude oil and the purchaser in which the ultimate price per barrel that the seller receives is tied to the sales price of refined products. This arrangement guarantees the refiner a minimum margin on product sales. Netback pricing was implemented by Saudi Arabia in late 1985 as part of its drive to regain market share. The terms of netback pricing arrangements are highly confidential, but by spring 1986 it was estimated that 3.5 to 4.5 million barrels of oil per day were sold under these terms by the Saudis and others. Arthur Andersen & Co., *Oil and Gas Reserves Disclosures: 1981-1985 Survey of 375 Public Companies, 1986* at s-9. It should be noted that in early 1987, the Aramco Companies were reported to have signed a long-term fixed price agreement with the Saudis. Whether this marks a shift away from netback pricing is not yet known, since the terms of these agreements are confidential.

[52] " Crude oil production and crude oil refining and marketing are almost completely unrelated aspects of the petroleum business. Crude oil today is a fungible commodity in trade. Petroleum companies sell most of their crude to third parties and buy most of their crude for refining purposes from third parties. This is the very nature of the business. There is not a direct tie between the wellhead and the gasoline pump within a company. ' Statement submitted by Gulf Oil Corp. in response to Committee questions in *Oil Industry Mergers, supra* note 13, at 426.

Table 42.—Reinvestment in Oil and Gas Exploration and Production (375 publicly held oil & gas producers)

Plowback ratios	Us.					Foreign					Worldwide				
	1985	1984	1983	1982	1981	1985	1984	1983	1982	1981	1985	1984	1983	1982	1981
Exporation and development[a]															
Majors	58%	64%	58%	68%	68%	32%	33%	37%	49%	47%	47%	52%	50%	62%	59%
Independents	57	56	62	105	134	75	59	52	93	99	62	58	60	104	133
Pipeline/utillty	74	78	83	107	106	51	63	81	90	94	68	75	79	104	103
Diversified	67	63	69	109	123	52	41	65	51	64	61	55	69	84	100
Weighted average	60%	64%	61%	77%	80%	37%	36%	42%	51%	52%	50%	53%	54%	69%	70%
All ***sources***[b]															
Majors	63%	111 %	62%	68%	68%	33%	57%	38%	49%	47%	500/0	89%	52%	62%	59%
Independents	93	93	92	131	145	75	65	63	122	104	91	89	87	130	144
Pipeline/utillty	113	90	107	108	106	74	63	162	92	94	107	84	111	105	104
Diversified	92	74	73	150	136	55	43	69	59	102	77	62	73	110	124
Weighted average	71%	103%	67%	85%	83%	38%	55%	45%	53%	59%	58%	85%	59%	74%	74%

[a]Excludes proved property acquisition costs
[b]Includes proved property acquisition costs

DEFINITIONS Plowback ratios are one measure of the level of a company's capital reinvestment m 011 and gas activities In this survey, plowback ratios are measured in Iwo different ways
- E&D Plowback compares cash flows from net production revenues to the costs recurred to acquire unproved acreage and explore and develop new reserves
- All Sources Plowback compares cash flows from net production revenues to the costs recurred to purchase existing proved reserves and search for new reserves

These ratios are designed to measure the degree to which companies are using production cash flows and capital from other sources to replace reserves whether through exploration and development or by acquiring existing reserves

SOURCE Arthur Andersen & Co 011 & Gas Reserves Disclosures 1981-85 Survey of 375 Public Companies, ' 1986, s-40

Companies have reorganized divisions to eliminate duplicative functions and streamline activities. As part of accompanying changes in investment priorities and philosophies, many firms have made sharp reductions in exploration and development budgets. Within E&D programs, capital spending has been directed away from unproven property acquisition and frontier-wildcat drilling toward more development drilling and intensive development of existing fields. (These shifts are in addition to the increases in development spending that would normally follow the high levels of exploratory activity in the early 1980s.) Although more development drilling generally leads to more production, over the longer term, lower exploration expenditures eventually will lead to lower production unless reserves are replaced from other sources. A continuation of these trends implies less overall exploration and development expenditures, as well as less R&D spending in an industry with historically low R&D spending.

With less exploration activity, exploration and production staffs have been slashed. Corporation-wide personnel reductions have been achieved through early retirements, hiring freezes, layoffs, and voluntary and involuntary separations. Oil industry employment is down by about 25 percent from 1980 levels according to early 1986 estimates. personnel cuts have meant one-time charges against earnings for severance benefits at many companies, but may mean lower costs in the future. Of course, the risk inherent in the loss of so many experienced people is that they will not return to the industry if oil prices and exploration activity rebound.

Financial Strategies

Pressures from large investors and a general shift in corporate management philosophy have given greater emphasis to "enhancing shareholder values" in addition to the bottom line profit or loss **as** a measure of financial performance. Restructuring activities have included strategies to alter **a** corporation's capital structure and to improve key indicators of financial performance (e.g., earnings per share, assets per share, return on assets, return on equity). These strategies include buying-back shares, increasing or decreasing long-term debt, major asset sales, spinoffs, and writedowns. Companies have sometimes increased or maintained dividends to increase shareholder returns even when it was necessary to borrow money to do so.

Share Buybacks.–Some companies have elected to make strategic investments to reduce the number of their outstanding shares through share buyback programs to boost indicators such

as assets per share, cash flow per share, and earnings per share. Share buy backs are also seen as a means of increasing the return to shareholders, but the cash benefits only accrue to those disposing of their shares. Before the 1986 tax law changes, share repurchase programs were generally preferable for tax reasons to increasing dividends because of the capital gains treatment on any increase in share value. The 1986 tax law changes and sharply restricted cash flows probably have reduced or eliminated most current buyback programs, but should financial conditions improve, such programs will again compete with exploration as an alternative use of discretionary cash flow.

It has been widely thought that the announcement of a buyback program also benefits those who retain shares, because share prices generally go up following such an announcement. However, the long-term effect of this share price boost is less clear; there is no evidence showing that stocks of companies participating in buyback programs outperform industry averages.

Share repurchases by oil companies are part of a broader trend in the economy, the replacement of equity with debt. Total equity retirement from mergers, buy backs, and leveraged buyouts exceeded new equity offerings of nonfinancial corporations by almost $160 billion in 1984-85 and by $35 billion during the first half of 1986.[53]

Oil company buy backs have been financed out of internally generated funds, and in some instances through new long-term debt. Many of the buyback programs were directed at open market purchases, but some were undertaken to eliminate certain classes of preferred stock, or to acquire the shares held by hostile tender offerors. Phillips petroleum and Unocal went heavily into debt to buy back their own shares to thwart takeover bids.

As shown in table 43, share repurchases absorbed billions of dollars in oil company funds in recent years. To a certain extent, share buy-

[53] "Surging Business Debt May Not Be a Cause for Alarm," *Business Week*, Nov. 10, 1986, p 28.

Table 43.—Share Repurchase Programs of Selected Oil Companies

Company	Year	Amount (millions)	Remarks
Phillips Petroleum Co.	1985	$4,972	Exchange offer of debt securities of $4.5 billion for 72.58 million shares of common stock in 1985
Texaco, Inc.	1984	$1,282	Purchase of common stock
	1983	74	
ARCO	1985	3,489	Bought back 28% of outstanding common stock before suspending program in January 1986 because of lower oil prices
	1984	781	
Exxon, Corp.	1985	$2,687	54 million shares
	1984	2,631	164 million shares
	1983	762	21 million shares
Sun Co., Inc.	1985	221	Purchase of common stock for treasury
	1984	203	
	1983		
Standard Oil Co.	1986	$100	Authorized for share purchase
	1985	561	Includes $523 million for 11 million shares repurchased in Aug. 1984 tender offer
	1983-84	70	Open market purchase of 1.5 million shares.
Mobil Oil Corp.	1982-83	482	Repurchase of shares for treasury
Amoco Corp.	1985	806	Net increase in treasury shares
	1984	1,191	
Mitchell Energy & Dev., Inc.	1986	3.7	Purchase of 218,400 shares
Louisiana Land & Exploration Co.	1986	16.4	Repurchase of 604,700 shares before suspending authorized repurchase of 2 million shares in 1985-86
	1985	10.8	Purchase of 10.7 million shares 1983-85
	1984	11.6	
	1983	212.8	
Shell Oil Co.	1984	$5,900	Parent company Royal Dutch Shell purchased remaining 31% of publicly held shares.

SOURCE: Office of Technology Assessment, based on company annual and quarterly reports 1984-87

backs raise the same concerns as mergers and acquisitions because substantial funds that could have been used for oil exploration were returned to shareholders. In the companies analyzed by OTA, share buy backs generally increased as a portion of discretionary cash expenditures relative to investment in E&P in recent years. In 1985, among large oil companies in the OTA group not involved in takeovers, share repurchase programs absorbed 23 percent of internal cash flow and domestic E&P spending 53 percent.

Changes **in Debt** Levels.–The oil industry had been historically cautious in using debt financing before the late 1970s, with the majors generally carrying lower debt loads than the independents. Many companies increased their debt levels in the early 1980s because debt financing was seen as more cost effective than equity financing to raise capital for expanded exploration activities. Also, interest payments, unlike dividends, are tax deductible, and an increase in debt, unlike an increase in shares, doesn't dilute shareholder values.

The oil industry has not been alone in increasing debt; all U.S. industries carried substantially higher long-term debt in 1986 than they did in 1980. *Business Week* estimates that the debt to equity ratio of the Nation's nonfinancial corporations soared from 35 percent in 1980 to an all time high of 47 percent in mid-1986.[54] Some Wall Street analysts view a rise in oil company debt and a corresponding decrease in equity as beneficial. They believe that U.S. oil companies are "overcapitalized" and thus, "too quick to make investments that might not have been very carefully worked out."[55] Greater reliance on external debt financing might, in their view, assure that exploration funds were invested in potentially more profitable areas and only after a rigorous review. Equity capital should not continue to be invested in oil and gas projects with below average returns, they reason, but rather should be returned to shareholders who might put it to more profitable use. Reducing equity capital is one reason for the trend in share repurchases discussed above.

Increased leverage has also been seen as a means to repel hostile takeovers. An SEC study of recent U.S. corporate takeovers found that companies that successfully fended off hostile takeovers tended to have higher debt loads than companies that were acquired.[56]

As noted previously, after initially increasing debt, many merged oil companies are now paying down or refinancing long-term debt to improve their leverage position. Chevron, Texaco, and Mobil have made significant progress in reducing the massive debt loads incurred in acquisitions of other companies, redirecting available cash flow to pay debt by slashing capital expenditures, cutting overhead, and selling assets.

Reducing the Asset Base.—Many companies have adopted strategies to downsize or reduce the asset base of the company, There are various sound business reasons for making a company smaller—to concentrate on core businesses, to remove subsidiaries that might create large losses in order to make the balance sheet stronger and to increase the percent return on assets. The asset shrinkage has been accomplished through a combination of spinoffs, sales, abandonments, and writedowns. Writedowns, reductions in the value of the assets carried on corporate books, were often taken to reflect price-related changes in the values of reserves and other assets, such as drilling rigs.[57] Asset sales bring cash directly to the company, while tax writeoffs yield some offsetting tax benefits.

In a move to improve other indicators of financial performance, some oil companies have resorted to spinoffs of unprofitable mining or drilling contractor subsidiaries to remove their im-

[54] Ibid

[55] See "Restructuring Shifts Focus of Oil Industry," Oil and Gas Journal, Nov. 18, 1985, pp. 87-92, citing Kurt Wulff of Donaldson, Luftkin, & Jenrette Securities Corp., p. 90.

[56] See John pound, Kenneth Lehn, and Gregg Jarrell, "Are Takeovers Hostile to Economic Performance?" *Regulation*, September/October 1986, pp. 25-30, 55-56.

[57] Some writedowns are largely voluntary decisions, but others are mandatory. SEC accounting rules for companies using the full cost accounting method, mostly Independent oil companies, require writedowns in the value of oil and gas reserves to reflect lower prices.

pacts on earnings. Other spinoffs involved the nonenergy businesses that oil companies bought during the 1970s diversification trend. When these subsidiaries are "spun off" or sold, the assets of the parent company are adjusted downward by an amount reflecting the value assigned to the newly separated entity. Interests in the newly independent entities are distributed to shareholders and then can be separately traded, creating additional opportunities to realize value on corporate assets. Examples of this trend include: Amoco's spinoff of Cyprus Mining; Arco's sale or liquidation of most nonenergy activities of its Anaconda Minerals subsidiary; and Noble Affiliates' spinoff of its drilling services subsidiary.

Oil and gas writedowns have generally been of very high cost reserves in remote frontier areas, e.g., Arco's writeoff of North Slope gas reserves. Other writedowns reflect discontinued operations or anticipated losses on asset divestitures, such as Mobil's writedowns in preparation for its planned divestiture of Montgomery Ward Department Stores.

Looking for New Internal Sources of Funds.– As companies look internally for new ways to generate cash flow, some have turned to employee pension funds as a potential source of funds. Exxon and Phillips have announced plans to tap overfunded employee pension plans by closing out the existing plans, purchasing annuities for participants and taking the excess funds, and starting a new employee pension plan. (The plans have "excess" funds over their anticipated liabilities because their investments have performed well.) Exxon anticipates that it will recapture about $1 billion from its employee pension fund, an amount equal to roughly one-third of its domestic E&P spending in 1986. This option may appear attractive to other large companies.

Creation of New Financial Instruments/Investment Arrangements.—The 1980s saw the creation and the expanded use of new financial instruments and investment vehicles, such as royalty trusts and master limited partnerships (MLPs), as ways to attract investment dollars and return value to shareholders. These arrangements offered several advantages over traditional stock ownership and previous investment devices. For example, MLPs pay no corporate income tax and thus pass through income to the partners or "unit holders" along with a share of partnership deductions that can be applied on the partners' personal income tax returns. (As discussed below, the 1986 tax law changes have limited some tax aspects of oil and gas MLPs.) The MLPs and royalty trust units also can be freely traded on stock exchanges and are thus more liquid than previous vehicles.

MLPs have also become an attractive mechanism for both small and large oil companies to return value to shareholders in response to pressures from aggressive investors or takeover threats. Some companies transferred many of their producing oil and gas properties to MLPs and royalty trusts and distributed interests to shareholders. The interests in the partnerships and trusts can be separately traded, perhaps resulting in a greater return to investors, while the parent company retains a managing interest and control over the properties. Some companies have also offered shares in the partnerships and royalty trusts to the public to raise exploration funds as an alternative to issuance of new common stock or long-term debt. (Some examples include Mesa Petroleum's Mesa Energy Partners, Sun Co. 's Sun Energy Partners, and Transco Energy's Transco Exploration Partners.)

Royalty trusts were a popular vehicle for independents to attract funds from outside investors for development drilling. But the creation of royalty trusts by converting existing corporate oil operations drew much criticism because they were seen essentially as a liquidation of a company's reserves position. Royalty trusts were said to reduce the availability of internally generated cash flow for exploration because income from the producing reserves in the trust and related corporate tax incentives were transferred to investors, who might not reinvest them in the oil industry.[58]

These vehicles drew billions to petroleum investments, but their future attractiveness is clouded by uncertainty over tax treatment of the

[58]See, for example, testimony of John H. Lichtblau, President, Petroleum Industry Research Foundation, Inc., in *Legislation Affecting Oil Merger Proposals, supra* note 1, at 374.

investment, the currently poor oil price outlook, and the prospect of lower overall tax rates. Although the tax bill maintained some of the tax advantages of oil and gas investments, there is concern that with lower tax rates, high-income investors will be less likely to invest in risky oil and gas ventures without a significant risk premium.

The 1986 tax law changes preserved many of the tax benefits for oil and gas exploration that can still be passed through to the unitholders. They did, however, limit the deductibility of "passive" losses from the partnerships, which could further diminish their attractiveness. Such passive losses can only be charged against similar passive income and cannot be used to shelter other income unless the partner shares in the risk of the venture at a level in excess of the investment. To continue the tax shelter aspect of oil and gas investments, investors must share liability exposure. Some industry tax experts have suggested that new investment packages will be created to overcome the passive loss restriction—perhaps a combination of a partnership interest and an insurance policy to cover losses in excess of the participation.

Effects of Restructuring

The long-term effectiveness of these restructuring efforts will not be known for several more years. Many cost-cutting moves will not provide immediate actual savings, and the sudden price drop and slide in revenues this year appears to have caught many companies by surprise. In addition, because major restructuring is unlikely to have been undertaken at random—each kind of restructuring was more likely to be undertaken by those companies most in need of the potential benefits it offered, or most vulnerable to it if the restructuring was imposed—the results of industrywide surveys of financial performance will be ambiguous about the "success" of restructuring. For example, many companies absorbed by hostile takeovers were vulnerable to such takeovers because of financial weakness; these companies may have been expected to undergo significant budget cutting with or without mergers, perhaps at levels greater than industry norms. Thus, post-merger statistics showing reduced investment levels beyond industry averages must be interpreted carefully to separate the effects of the takeover from other market effects.

Nevertheless, it is quite telling that extensive assurances about the positive effects of mergers were given to Congress in hearings held to explore the effects of the wave of mergers on the industry, and the more easily measured of these positive effects (increased E&D activity) have clearly not materialized. It seems clear that the **short-term** effects of mergers on E&D spending, and probably on R&D as well, have been negative. The short-term effects of mergers on less easily measured characteristics, such as the "efficiency" of E&D activity, and the effects of other restructuring activities have not been carefully measured.

Chapter 7

Production Loss From Reduced Drilling

All oil wells experience a declining production rate as reservoir pressures decline and as the oil closest to the wellbore is produced. Although different geologic conditions, production strategies, and oil characteristics yield different decline rates, **in all cases production** in a field can only be maintained by proceeding with secondary and tertiary recovery and by drilling additional producing wells. And as production rates in some fields inevitably decline, discovery wells must find new fields to exploit if national production is to be maintained.

As noted above, one source of lost domestic oil production resulting from low oil prices is the early abandonment of stripper wells and other marginal wells. Additional production will be lost as existing wells continue their natural declines and too few additional wells are drilled to compensate for these declines. As discussed earlier, declines may be expected in all aspects of drilling, from shallow, low-cost development wells to the most expensive offshore and arctic wells on the frontier. The reduced level of development drilling will affect production the soonest, because some of these wells can often be producing weeks or a few months after they are "spudded" (drilling has begun). At the opposite end of the spectrum, exploration wells in frontier areas may precede production by a decade or more as infrastructure is built and, in some deep offshore cases, as new production technology is designed and tested.

In order to evaluate accurately the effect of low oil prices on drilling and, eventually, on production, it is necessary to understand how the oil price change and other factors associated with it will change the level of drilling activity, the distribution of drilling (geographically, by the nature of the target, etc.), and the likely success of the drilling in adding to reserves and production. In OTA's view, there are strong uncertainties with all of these factors.

The Level of Drilling Activity

From 1981 to 1985, oil drilling rates remained very high despite declining prices and a decline in the number of operating drilling rigs (from *3,970* rotary rigs in 1981 to 1,980 in 1985[1]); during these years, the number of oil well completions ranged between 37,000 and 43,000 wells per year, with 1984 being the peak year.[2] Apportioning dry **holes between** oil and gas according to the ratio of oil to gas completions, the total wells drilled "for oil, " successful and dry, ranged between 55,000 and 60,000 thousand wells per year.

The rig count hovered around *700* for much of 1986, and, around mid-year, analysts expected the industry to drill somewhat over 30,000 "oil wells" (successful and dry)[3] during that year. Assuming that prices remain low, it is by no means clear whether drilling activity in 1987 and after will rise, fall, or remain at the same general level. Some of the 1986 activity is a short-term continuation of activity planned and begun before the price drop, with much of the capital investment sunk. For some of these projects, there will be no replacement upon their conclusion. Some additional projects will be continued because they are necessary to hold leases or fulfill contractual obligations, and these too may have no replacements. Finally, some industry analysts argue that the list of viable drilling prospects at 1986 oil prices is a very limited one, so that a continuation of those low prices for any length of time would exhaust the industry's inventory of drillable prospects and force down the drilling rate.

[1] Independent Petroleum Association of America, "United States Petroleum Statistics, 1986. "

[2] Ibid.

[3] In industry usage, an oil well is a successfully completed oil-producing well. In this section, OTA added a proportional number of dry holes–unsuccessful wells that are abandoned–to the number of completed wells, and thus our terminology will not correspond to the standard usage.

On the other hand, there are many independent drillers who claim that they have access to drilling prospects that are economic, but cannot drill because of a lack of capital. Although capital availability has seemingly evaporated from the oil market, it seems unlikely that this will continue for long if there are reasonable prospects for profitable investments. As discussed in chapter s, there are substantial disagreements about the number of economic prospects still available to the industry.

The Distribution of Drilling Targets, and the Likely Success at Adding Reserves and Production

As discussed in chapter 6, "The Efficiency of E&D Activities," reductions in exploration and development activity because of the price drop will not be uniform, since changing economics affects different regions, geologic targets, and activity types differently. For example, most of OTA's industry contacts expect drilling activity to focus on low risk prospects, with shallow development activity to sustain only a moderate decline and high-risk exploratory and deep drilling activity to suffer a substantial decline. A sign that this is beginning to happen is the downward shift in average depth of new wells; for the first 8 months of 1986, the average well depth was 4,153 v. 4,440 feet for 1985.[4] This shift in activity probably would tend to increase well success rates but decrease the reserves found per well drilled. On the other hand, some geographic shifts will tend to favor those areas that traditionally have paid off more handsomely in terms of reserves added per well. Table 44, which shows the 1980-1984 average reserves per oil well drilled for the nine regions in the United States, amply illustrates why a regional shift in drilling can greatly affect overall drilling results in terms of reserve additions.

Projections of regional drilling rates for 1986 made in July of that year by the Oil and Gas Journal,[5] a respected industry publication, indicate

Table 44.-Reserve Additions Per Oil Well Drilled, 1980-1984 Average (barrels par well)

Region	Reserves **added** per oil well (including dry holes)
Alaska	2,524,000
California	177,000
Rocky Mountains and northern Great Plains	78,000
West Texas and eastern New Mexico	**49,000**
Gulf Coast	**71,000**
Midcontinent	14,000
Eastern interior.	5,000
Michigan basin	62,000
Appalachian.	6,000
National average.	50.000

SOURCE: J.P. Riva, Jr., "Domestic Oil Production and Reserves Projected to 2000 on the Basis of Regional Drilling and Per Well Reserve Additions, " Congressional Research Service, 1986.

that drilling will tend to favor regions with high historic rates of reserve additions per well, though not uniformly. For example, 1986 drilling in Alaska is expected to be higher than normal, about 265 wells drilled compared to an average of 150 wells drilled per year during 1980-84. California drilling also is expected to be high, about 2,460 wells, only slightly lower than recent levels. (However, in both these States, much of this drilling requires lengthy planning and considerable advance capital investment, and thus the 1986 drilling level may not reflect the price drop as much as activity levels in other areas.) The Gulf Coast, another "high reserves per well" area, also holds up well at about 6,700 wells, one-third under recent average levels. On the other hand, activity in the Rocky Mountains and Northern Great Plains (2,1 50 wells) and Michigan Basin (380 wells), the two other "high reserves per well" areas, is projected to decline at about the national rate.

The implication of this nonuniformity in the reduction of drilling activity is that 1986 oil reserve additions are not likely to be as low as might be expected from the percentage fall in the national drilling rate. Had the reduction been uniform and had the overall rate of reserve additions per well remained at recent levels, the expected 1986 reserve additions would have been 1.6 billion barrels. Applying the historic per well reserve rates to the regional drilling breakdown gives expected 1986 reserve additions of about 2.2 billion barrels, a value only slightly below the average for

[4] Energy Information Administration, *Short-Term Energy Outlook Quarter/y Projections, Oct. 1986,* DOE/EIA-0202(86/4Q), Nov. 1986.
[5] J.C. McCaslin, "U.S. Drilling to Fall 47 percent This Year, " *Oil and Gas Journal,* July 28, 1986.

the 1980s. Note, however, that the latter value is not the "correct" value either, because:

- wide year-to-year swings **in regional finding rates virtually guarantee that any individual year's average will vary considerably from the historic rate;**
- **the changes in drilling patterns caused by the lower oil prices occur within regions as well as across them, and applying the regional finding rates does not take intraregional shifts into account;**
- **in some key States—California, in particular –past increases in reserves depend significantly on enhanced oil recovery** (EOR) in addition to exploratory and development drilling, and using such simple measures as "reserves per well" cannot capture the effects of drastic changes in the attractiveness of EOR investments;[6] and/or
- the drilling mix is said to be shifting towards development drilling and away from exploratory drilling; such a change in the drilling mix would tend to lower overall finding rates.

Projecting Oil Reserve Additions and Production Based on Extrapolating Regional Drilling Patterns and Per Well Reserve Additions

Joseph Riva of the Science Policy Research Division, Congressional Research Service has projected regional and U.S. **oil reserve additions and production to the year 2000[7] by using the average reserve additions achieved per oil well drilled** for each of nine regions during the 5-year period 1980-84, as discussed above, and assuming that projected low rates of drilling for 1986[8] will continue indefinitely. As noted previously, an "equilibrium" in drilling has by no means been reached, and thus an assumption of constant drilling in each region is clearly a risky one . . . as is the assumption that per well reserve additions will remain steady at the 1980 to 1984 average. Nevertheless, this is a useful "What if. . ." analysis that can act as a counterpoint to similar analyses that postulate a considerably lower rate of reserve additions based on alternative assumptions that OTA considers overly pessimistic.

Tables 45 through 53 present the past and projected production, proved reserves, and reserves to production (R/P) ratios for the nine regions. Table 54 presents similar projections for the United States.

The regional tables show extremely interesting variations in the projected year *2000* production rates as compared to current rates. By the year *2000,* Alaska and California production rates are projected to increase by 2 and 25 percent respectively. This is contrary to current expectations. According to virtually all industry sources, Alaskan production, although it is actually somewhat higher this year than last, is expected to begin a long decline beginning around 1989. The source of the decline will be the supergiant Prudhoe Bay field, which is expected to fall from its present production rate of 0.55 billion barrels per year (1.5 million barrels per day) by more than one-half by 1995 and more than three-quarters by year 2000.[9] In this case, extrapolation of historic reserve additions and current drilling rates does not appear to work. Although recent development of new reservoirs at Prudhoe has been quite successful, there are few such opportunities left, and the recent exploratory drilling record has been disappointing: it may be that the primary possibility for a substantial recovery, after production has begun its decline, lies with the Arctic National Wildlife Refuge, discussed in chapter s. And were the Arctic National Wildlife Refuge to be successfully explored and developed, production is unlikely to begin before the year 2000.

In California's case, maintaining or increasing production depends on offshore development and exploration and on enhanced oil recovery. Between 1980 and 1985, almost half of California's oil reserve additions came from enhanced

[6] Although most EOR projects require drilling for injection and often for production.

[7] J. P. Riva, Jr., "Domestic Oil Production and Reserves Projected to 2000 cm the Basis of Regional Drilling and Per Well Reserve Additions," Congressional Research Service, Library of Congress, Dec. 9, 1986.

[8] *Oil and Gas Journal,* July 28, 1986, op. cit.

[9] J.P. Riva, Jr., op. cit.

Table 45.-Past and Projected Alaska Oil Status

Year	Product ion 10^9 bbls/yr	Proved reserves 10^9 bbls	R/P[a]	Total oil wells	Average oil rig count	Wells per rig	Reserve additions 10^9 bbls/well per oil well
1970	0.083	10.149	122/1	72	13	5.5	0.136111
1975	0.070	10.037	143/1	61	13	4.7	0.000213
1980	0.591	8.751	15/1	122	14	8.7	0.003828
1981	0.592	8.283	14/1	159	22	7.2	0.000780
1982	0.627	7.406	12/1	201	21	9.6	–0.001244[b]
1983	0.665	7.307	11/1	159	14	11.4	0.003560
1984.	0.638	7.563	12/1	157	14	11.2	0.005694
1985.	0.667	7.056	11/1	20	20	1.0	0.008000
1986.	0.67	7.060	11/1	245 est.			
1990.	0.67	7.060	11/1				
1995.	0.68	7.050	10/1				
2000.	0.68	7.050	10/1				

aproved reserves/annual production.
bNegative values for reserve additions per welloccur whenlarge negative revisions are recorded for the region during the reference year

SOURCE: J.P. Riva, Jr., "Domestic Oil Production and Reserves Projected to 2000 on the Basis of Regional Drilling and Per Well Reserve Additions, " Congressional Research Service, 1986.

Table 46.— Past and Projected California Oil Status

Year	Production 10^9 bbls/yr	Proved reserves 10^9 bbls	R/P[a]	Total oil wells	Average oil rig count	Wells per rig	Reserve additions 10^9 bbls/well per oil well
1970	0.372	3.984	11/1	1,970	50	39.4	0.000057
1975	0.322	3.648	11/1	2,184	78	28.0	0.000189
1980	0.360	5.470	1 5/1	2,416	116	20.8	0.000234
1981	0,383	5.441	14/1	3,011	152	19.8	0.000118
1982	0.394	5.405	14/1	2,464	125	19.7	0.000145
1983	0,400	5.348	1 3/1	2,242	103	21.7	0.000153
1984	0.415	5.707	1 4/1	3,259	104	31.3	0.000237
1985	0.417	5.801	14/1	2,959	81	36.5	0.000173
1986	0.42	5.820	14/1	2,460 est.			
1990	0.44	5.830	13/1				
1995	0.48	5.700	1 2/1				
2000	0.52	5.360	10/1				

aProved reserves/annual production.

SOURCE: J.P. Riva, Jr., "Domestic Oil Production and Reserves Projected to 2000 on the Basis of Regional Drilling and Per Well Reserve Additions," Congressional Research Service, 1986.

Table 47.—Past and Projected Rocky Mountains and Northern Great Plains Oil Status

Year	Production 10^9 bbls/yr	Proved reserves 10^9 bbls	RIP[a]	Total oil wells	Average oil rig count	Wells per rig	Reserve additions 10^9 bbls/well per oil well
1970	0.281	2.086	7/1	2,645	125	21.2	0.000070
1975	0.259	1.849	7/1	2,835	177	16.0	0.000046
1980	0.258	1.777	7/1	3,478	283	12.3	0.000122
1981	0.257	1.660	6/1	5,501	432	12.7	0.000025
1982	0.249	1.709	7/1	4,135	355	11.6	0.000072
1983	0.252	1.900	8/1	3,693	209	17.7	0.000120
1984	0.254	1.889	7/1	4,555	267	17.1	0.000053
1985	0.255	2.014	8/1	3,211	212	15.1	0.000116
1986	0.25	1.930	8/1	2,154 est.			
1990	0.23	1.640	7/1				
1995	0.20	1.430	7/1				
2000	0.18	1.320	7/1				

aProved reserves/annual production.

SOURCE: J.P Riva, Jr., "Domestic Oil Production and Reserves Projected to 2000 on the Basis of Regional Drilling and Per Well Reserve Additions," Congressional Research Service, 1986.

Table 48.—Past and Projected West Texas and Eastern New Mexico Oil Status

Year	Product ion 10^9 bbls/yr	Proved reserves 10^9 bbls	R/P[a]	Total oil wells	Average oil rig count	Wells per rig	Reserve additions 10^9 bbls/well per oil well
1970	0.792	7.876	10/1	4,542	187	24.3	0.000245
1975	0.809	6.496	8/1	6,933	276	25.1	0.000035
1980	0.670	6.240	9/1	9,948	379	26.2	0.000070
1981	0.645	6.272	10/1	13,112	520	25.2	0.000052
1982	0.625	5.977	10/1	12,768	337	37.9	0.000026
1983.	0.620	5.923	10/1	12,563	357	35.2	0.000045
1984.	0.608	6.052	10/1	14,490	394	36.8	0.000051
1985.	0.620	6.454	10/1	12,946	457	28.3	0.000079
1986.	0.62	6.21	1011	7,703 est.			
1990.	0.59	5.32	9/1				
1995.	0.53	4.45	8/1				
2000.	0.48	3.85	8/1				

[a]Proved reserves/annual production

SOURCE J.P. Riva, Jr, "Domestic Oil Production and Reserves Projected to 2000 on the Basis of Regional Drilling and Per Well Reserve Additins," **Congressional** Research Service. 198

Table 49.— Past ad Projected Gulf Coast Oil Status

Year	Production 10^9 bbls/yr	Proved reserves 10^9 bbls	R/P[a]	Total oil wells	Average oil rig count	Wells per rig	Reserve additions 10^9 bbls/well per oil well
1970.	1.381	12.174	9/1	4,923	296	16.6	0.000231
1975.	1.118	8.470	8/1	4,613	303	15.2	0.000055
1980.	0.812	5.643	7/1	7,370	584	12.6	0.000100
1981	0.774	5.707	7/1	10,036	831	12.1	0.000083
1982.	0.755	5.273	7/1	8,891	514	17.3	0.000036
1983.	0.773	5,214	7/1	9,989	509	19.6	0.000072
1984.	0.803	5.148	6/1	11,957	561	21.3	0.000062
1985.	0.786	5,012	6/1	9,987	410	24.4	0.000065
1986.	0.78	4.71	6/1	6,727 est.			
1990.	0.65	3.75	6/1				
1995.	0.55	3.24	6/1				
2000.	0.51	3.03	6/1				

[a]Proved reserves/annual ProductIon

SOURCE: J.P. Riva, Jr. "Domestic Oil Production and Reserves Projected to 2000 on the Basis of Regional Drilling and Per Well Reserve Additions," Congressional Research Service, 1986.

Table 50.—Past and Projected Midcontinent Oil Status

Year	Production 10^9 bbls/yr	Proved reserves 10^9 bbls	R/P[a]	Total oil wells	Average oil rig count	Wells per rig	Reserve additions 10^9 bbls/well per oil well
1970.	0.324	2.108	7/1	4,560	118	38.6	0.000053
1975.	0,231	1.759	8/1	5,512	197	28.0	0.000035
1980.	0.200	1.329	7/1	12,852	418	30.7	0.000003
1981	0.218	1.428	7/1	17,695	748	23.7	0.000018
1982.	0.224	1.493	7/1	15,617	626	24.9	0.000016
1983.	0.221	1.380	6/1	14,195	396	35.8	0.000010
1984.	0.233	1.425	6/1	13,331	388	34.4	0.000021
1985.	0.223	1.503	7/1	9,616	290	33.2	0.000031
1986.	0.22	1.37	6/1	6,637 est.			
1990.	0.16	.98	7/1				
1995.	0.12	.79	7/1				
2000.	0.10	.71	7/1				

[a]Proved reserves/annual production

SOURCE: J.P Riva, Jr. "Domestic Oil Production and Reserves Projected to 2000 on the Basis of Regional Drilling and Per Well Reserve Additions," Congressional Research Service, 1986

Table 51.—Past and Projected Eastern Interior Oil Status

Year	Production 10^9 bbls/yr	Proved reserves 10^9 bbls	R/P[a]	Total oil wells	Average oil rig count	Wells per rig	Reserve additions 10^9 bbls/well per oil well
1970	0.063	0.327	5/1	1,617	15	108	0.000003
1975	0.038	0.224	6/1	2,159	18	120	0.000019
1980	0.027	0.171	6/1	4,859	27	180	–0.000001[b]
1981	0.027	0.181	7/1	6,802	45	151	0.000005
1982.	0.030	0.214	7/1	7,321	84	87	0.000009
1983.	0.030	0.204	7/1	7,591	67	113	0.000003
1984.	0.032	0.227	7/1	6,458	49	131	0.000009
1985.	0.034	0.218	6/1	4,263	33	129	0.000006
1986.	0.03	0.21	7/1	3,423 est.			
1990.	0.03	0.17	6/1				
1995.	0.02	0.14	7/1				
2000.	0.02	0.14	7/1				

[a]Proved reserves/annual production.
[b]Negative values for reserve additions per Well occur when large negative revisions are recorded for the region during the reference year

SOURCE: J.P Riva, Jr, "Domestic Oil Production and Reserves Projected to 2000 on the Basis of Regional Drilling and Per Well Reserve Additions," Congressional Research Service, 1986

Table 52.—Past and Projected Michigan Basin Oil Status

Year	Production 10^9 bbls/yr	Proved reserves 10^9 bbls	R/P[a]	Total oil wells	Average oil rig count	Wells per rig	Reserve additions 10^9 bbls/well per oil well
1970	0.012	0.046	4/1	201	8	25	0.000030
1975	0.024	0.093	4/1	439	23	19	0.000080
1980	0.037	0.205	6/1	530	25	21	0.000157
1981	0.034	0.240	7/1	650	31	21	0.000106
1982	0.029	0.184	6/1	773	27	29	– 0.000035[b]
1983	0.031	0.209	7/1	671	26	26	0.000083
1984	0.027	0.180	7/1	902	28	32	–0.000002[b]
1985	0.030	0.191	6/1	638	28	23	0.000064
1986	0.03	0.18	6/1	382 est.			
1990	0.03	0.14	5/1				
1995	0.02	0.14	7/1				
2000	0.02	0.14	7/1				

[a]Proved reserves/annual production.
[b]Negative values for reserve additions per well occur when large negative revisions are recorded for the region during the reference Year

SOURCE: J.P Riva, Jr., "Domestic Oil Production and Reserves Projected to 2000 on the Basis of Regional Drilling and Per Well Reserve Additions," Congressional Research Service, 19S6

Table 53.—Past and Projected Appalachians Region Oil Status

Year	Production 10^9 bbls/yr	Proved reserves 10^9 bbls	R/P[a]	Total oil wells	Average oil rig count	Wells per rig	Reserve additions 10^9 bbls/well per oil well
1970	0.018	0.243	14/1	1,323	20	66	0.000010
1975	0.017	0.210	12/1	1,550	17	91	0.000006
1980	0.016	0.181	1 1/1	4,336	55	79	0.000008
1981	0.015	0.174	12/1	4,928	71	69	0.000002
1982	0.019	0.196	10/1	3,490	45	78	0.000012
1983	0.024	0.228	10/1	2,926	31	94	0.000016
1984	0.025	0.232	9/1	3,217	38	85	0.000012
1985	0.020	0.167	8/1	3,052	43	71	–0.000015[b]
1986	0.02	0.16	8/1	2,483 est.			
1990	0.02	0.12	6/1				
1995	0.01	0.08	8/1				
2000	0.01	0.08	8/1				

[a]Proved reserves/annual Production.
[b]Negative values for reserve additions per well occur when large negative revisions are recorded for the region during the reference Year

SOURCE' J.P. Riva, Jr., "Domestic Oil Production and Reserves Projected to 2000 on the Basis of Regional Drilling and Per Well Reserve Additions," Congressional Research Service, 1986.

recovery operations in the large heavy oilfields of the San Joaquin basin, and an additional third came from large oilfields discovered offshore.[10] Further activity in the offshore may be restricted by California's environmental aversion to offshore drilling. Further development of EOR operations may require higher prices than today's, and there are air quality restrictions as well; however, the rather basic techniques used in many of the California fields are not at the high end of the cost spectrum for EOR,[11] and price might not be as much of a constraint here as it would be elsewhere. An important source of uncertainty is the potential for technological improvements that could reduce production costs. In conclusion, fulfilling the projection for California production will require success in two difficult areas—not impossible, but surely requiring considerable good fortune.

Year 2000 production rates in all other regions are projected to decline from 1985 rates, as follows:

Rocky Mountains and northern Great Plains	–29%
West Texas and eastern New Mexico	–23%
Gulf Coast	–35%
Midcontinent	–55%
Eastern interior	–41%
Michigan basin.	–33%
Appalachian region	– 50%

[10] Ibid.
[11] Personal communication, Joseph Riva, Congressional Research Service.

These very substantial projected declines demonstrate the fragility of domestic oil production, especially given the uncertainty associated with our ability to maintain production levels in Alaska and California.

Table 54 shows that the projected decline in total U.S. production associated with the drop in drilling activity is 17 percent by the year 2000. This is a modest decline when compared to the projected declines discussed in chapter 2. However, this projection does not account for the possibility that large numbers of existing wells may be abandoned as uneconomic, as discussed in the previous section. Although there appear to be problems with the analysis of stripper well abandonments conducted by the interstate oil Compact Commission (IOCC), it is worthwhile to incorporate their projections into the drilling projections above. Table 55 illustrates how future production might change if the IOCC's projected production losses at oil prices of $15/bbl were to occur. The primary effect would be to increase the expected year 2000 production loss from 17 to 22 percent.

Furthermore, a less optimistic–and many would say more realistic—projection of Alaskan and Californian production would substantially affect the national estimate. For example, assuming that only about half the Prudhoe decline can be replaced with production **from other fields (as**

Table 54.—Past and Projected United States Oil Status

Year	Production 10^9 bbls/yr	Proved reserves 10^9 bbls	R/P[a]	Total oil wells	Average oil rig count	Wells per rig	Reserve additions 10^9 bbls/well per oil well
1970	3.328	39.001	12/1	21,522	832	26	0.000590
1975	2.901	32.682	11/1	26,253	1,102	24	0.000051
1980	2.975	29.805	10/1	45,316	1,901	24	0.000066
1981	2.949	29.426	10/1	60,940	2,852	21	0.000042
1982	2.950	27.858	9/1	55,600	2,134	26	0.000025
1983	3.020	27.735	9/1	52,577	1,712	31	0.000055
1984	3.037	28.446	9/1	61,399	1,843	33	0.000061
1985	3.052	28.416	9/1	48,489	1,574	31	0.000062
1986	3.04	27.65	9/1	32,234 est.			
1990	2.82	25.01	9/1				
1995	2.61	23.02	9/1				
2000	**2.52**	**21.68**	**9/1**				

a Proved reserves/annual production

SOURCE: J.P. Riva, Jr., "Domestic Oil Production and Reserves Projected to 2000 on the Basis of Regional Drilling and Per Well Reserve Additions." Congressional Research Service, 1986.

Table 55.—impact of Increased Stripper Well Abandonment on Low Drilling Scenario Production and Reserves Projections

Year	Production (billion bbl/yr)	Proved reserves (billion bbls)
1985	3.052	28.416
1986	3.04 – .10 = 2.94[a]	27.65 –.73 = 26.92[b]
1990	2.76	24.33
1995	2.52	22.35
2000	2.38	21.26

[a]That is, stripper production of .10 billion bbl/yr is lost.
[b]Stripper reserves of .73 billion bbls are lost.

SOURCE: J.P. Riva, Jr., "Domestic Oil Production and Reserves Projected to 2000 on the Basis of Regional Drilling and Per Well Reserve Additions," Congressional Research Service, 1986.

noted, a three-quarter decline in current Prudhoe Bay production is expected by 2000), the year 2000 production rate would be about 2.17 billion barrels per year, a 29 percent decline from 1985 production. An important-and sobering–note about this computation is that much of Alaska's expected production decline is not price but geology dependent. Although lower prices will stifle some development and exploration, and some production also will be dependent on technology development, much of the production decline was expected at higher prices.

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