Materials and Manpower Requirements

For U.S. Oil and Gas Exploration and Production – 1979-1990

National Petroleum Council

December 1979

NATIONAL PETROLEUM COUNCIL
1625 K Street, N.W., Washington, D.C. 20006 (202) 393-6100

December 12, 1979

My dear Mr. Secretary:

On behalf of the members of the National Petroleum Council, I am pleased to transmit to you herewith the report on *Materials and Manpower Requirements for U.S. Oil and Gas Exploration and Production--1979-1990* as approved by the Council at its meeting on December 12, 1979. This study, which is in response to a June 20, 1978 request from the Secretary of Energy, concludes that the availability of equipment, materials, services, and manpower necessary for domestic exploration and production of oil and natural gas is unlikely to constrain increased future industry activity levels. The establishment of a stable and predictable business climate conducive to accelerated expansion of investment, drilling activity, and support capacity is essential to this conclusion.

A report of this type, by necessity, addresses a continually changing environment. There have been a number of changes in the domestic and international environments since late 1978 and the first half of 1979 when most of the basic analyses were conducted for this report. Current international events emphasize the President's wisdom in promoting the development of all domestic energy resources and indicate that further actions in this direction are imperative. Such events also underscore the need for the Nation to maintain long range and consistent energy goals understood by all.

Domestically, there has been recent movement toward improving the environment for the development of oil and gas resources, specifically in the areas of crude oil pricing, implementation of the Natural Gas Policy Act, enhanced oil recovery, and OCS lease schedules. However, some changes are also being debated which may prove to be disincentives to increased activities. Because the effects of both types of changes are yet to be fully manifested, their impact cannot be fully assessed nor incorporated in this report.

Eventhough there have been some changes in the environment which existed when much of this study was conducted, the Council feels that the basic conclusions and recommendations remain valid. While current improvements in incentives are encouraging, more important is the fostering of the perception that these improvements will not be rescinded and that the Nation's policy of promoting domestic energy production will be continued. Such a perception will be required for the generation of the activity levels necessary to improve future domestic oil and gas supply and for the addition of manufacturing and service capacities necessary to support such activity levels. Potential shortages in critical equipment, materials, and services at substantially increased activity levels are solvable only if suppliers of such equipment, materials, and services perceive a future without the extremes in cyclical industry activity experienced in the past.

The National Petroleum Council sincerely hopes that this study will be of benefit to you and the government in your efforts to encourage increased domestic oil and gas supply.

Respectfully submitted,

C H Murphy Jr

C. H. Murphy, Jr.
Chairman

Honorable Charles W. Duncan
Secretary of Energy
Washington, D.C.

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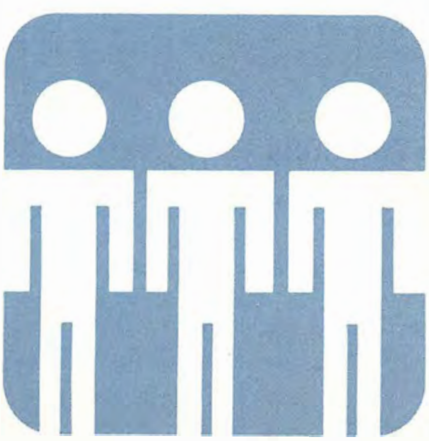

National
Petroleum
Council

December 1979

John P. Harbin, Chairman
Committee on
Materials and Manpower Requirements

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The sole purpose of the National Petroleum Council is to advise, inform, and make recommendations to the Secretary of Energy on any matter requested by the Secretary relating to petroleum or the petroleum industry.

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Table of Contents

Preface

Since 1973, significant increases in levels of activity have been experienced in domestic oil and gas exploration and development. Further increases are necessary because a goal of the nation's energy policy is to increase oil and gas production from domestic sources. Concern has been expressed that future activity levels may be constrained due to shortages of critical materials, equipment, or trained personnel.

By letter dated June 20, 1978, the National Petroleum Council, an industry advisory committee to the Secretary of Energy, was requested to prepare an analysis of the materials and manpower requirements for U.S. oil and gas exploration and development. The Council last prepared such a study in 1974, entitled *Availability of Materials, Manpower and Equipment for the Exploration, Drilling and Production of Oil—1974-1976*. In requesting the new study, the Secretary specified that it should be:

> . . . a comprehensive study of the materials and manpower requirements for oil and gas exploration and development. This study should focus on the period 1979-1981, but should also address the longer term situation. Particular attention should be paid to identifying areas of potential shortages in critical materials and manpower and methods of preventing such shortages. In addition, the impact of federal, state, and local laws and regulations should be explained and any appropriate recommendations for changes should be made. (See Appendix A for the complete text of the Secretary's letter.)

To aid it in addressing this request, the National Petroleum Council established the Committee on Materials and Manpower Requirements under the chairmanship of John P. Harbin, Chairman of the Board and Chief Executive Officer, Halliburton Company. R. Dobie Langenkamp, Deputy Assistant Secretary for Oil, Natural Gas, and Shale Resources, U.S. Department of Energy, served as Government Cochairman of the Committee. The Committee was assisted by a Coordinating Subcommittee, an Outlook and Materials Subcommittee, and a Government Subcommittee. Under the subcommittees, seven task groups were established—Geological and Geophysical Services, Drilling Equipment, Tubular Steel, Production Equipment, Well Servicing, Business Environment, and Regulatory Impact. The individuals who participated in the study are experts in their respective fields. They were from exploration and production companies, manufacturers and suppliers of oilfield equipment, drilling and construction contractors, service companies, financial organizations, and academic institutions. (Rosters of all study participants are included in Appendix B.)

The report's primary focus is on the requirements associated with the accelerated development of domestic oil and gas resources in the 1979-1981 period, and the service and supply industry's capability of fulfilling these requirements; however, longer term (1985 and 1990) situations are also examined. In addition, the study assesses the impact of the regulatory environment on future activities. While a detailed analysis of future worldwide requirements and capacities is not made, the net effect of the export and import of materials and equipment is examined for domestic impact. The impact of significant oil industry downstream (refining and transportation) expansion or large-scale synfuel development is not addressed.

The projected range of possible future drilling activity is employed in the report for comparison with service and supply capacities as a means of determining possible constraints, and is not intended as a forecast of what will occur. No attempt is made to determine the oil and gas reserve additions or producing rates which would result from activity level projections in this report. The conclusions in this report are based on the judgment that the activity projections provide a sufficiently broad range against which to test availability of materials and manpower, although somewhat higher or lower activity levels could occur.

Conclusions and Recommendations

Conclusions

Based on broad industry surveys and the expertise of the study participants, it is the Council's judgment that the availability of equipment, materials, and services necessary for domestic exploration and production of oil and natural gas is unlikely to be a constraint to future industry activity levels. It is also the Council's judgment that, although professional and skilled personnel are currently in tight supply, the manpower required for exploration, drilling, and production (including that required for well servicing and equipment manufacture) will be adequate to support substantial increases in activity.

Exploration and production activity levels are significantly affected by federal laws and regulations. Any changes in laws and regulations which improve the business environment, including the expectation of profitability, and thereby increase capital availability and investment opportunities, will directly increase activity. Satisfactory resolution of environmental preservation issues and increased availability of federal lands will also have a favorable impact on activity. Exploration and production companies, in response to surveys conducted for this study, indicated they are willing and able to substantially expand exploration and production activity. The level of this expansion over the 1980-1985 period is dependent upon federal policies with regard to oil and gas pricing, environmental preservation issues, and the pace of federal leasing being made more certain and conducive to investment expansion than now expected by the exploration and production industry. Its willingness to accelerate investments, given an improved business environment, indicates the industry's confidence in the nation's oil and gas resource base.

The manufacturing, supply, and service industries currently have spare capacity. These industries have demonstrated their ability in the 1974-1978 time frame, as in previous periods, to respond to rapid increases in demand and to surpass even their own estimates of capability. Existing spare capacity, together with expansion plans, should be adequate to supply the growth in demand resulting from increases in drilling activity within the range projected to be possible through 1981. In the longer term, the capability to add capacity where needed is sufficient to supply a substantial growth in demand, provided that adequate incentives and an improved business climate exist. During periods of increasing activity or geographic redistribution of activity, it should be recognized that there are likely to be occasional spot shortages of some items. However, this condition is normal, having occurred throughout periods of changing activity, and is alleviated as the industry responds to the changing demand. Although inconvenient, these conditions generally pose no fundamental long-term constraint.

It is felt that the discovery and subsequent development of any major foreign frontier areas should not constrain domestic activity levels. Because U.S. drilling constitutes approximately 80 percent of worldwide activity (wells and footage), even several large finds would not have a significant impact on total activity and associated demand for materials and manpower requirements. Also, the long lead time between a discovery and the development/production phase, during which time equipment and materials demand is most intensive, should allow sufficient time for capacity expansion. Foreign consumption of U.S. manufactured goods may not increase significantly due to foreign encouragement of local manufacture when a substantial local market develops. Although unpredictable large orders from Communist Bloc countries could cause some spot shortages, the long-term effect on ability to meet domestic demand should be negligible.

Although the Council believes there will be capacity to support an important and necessary increase in activity, the study did identify a number of areas where capacity would be tight and where constraints could develop, especially with a substantial increase in activity. The most significant concerns appear in the general area of iron and steel.

- The projected domestic supply of oil country tubular goods (oil well casing, tubing, and drill pipe) would fall short of demand by 1985 with a substantial increase in activity and by 1990 with a lesser increase, assuming present patterns of imports and exports. Worldwide capacity should allow the shifting of these patterns to meet domestic needs. However, this would result in increasing reliance on potentially insecure foreign sources.
- Many manufacturers expressed concern for adequate future availability of castings and forgings. A significant factor in the current supply situation is the loss of capacity which has resulted from the shutdown of many small foundries unable economically to meet EPA and OSHA requirements. This looms as a potential, although unquantified, constraint on the availability of valves, wellheads, and other production equipment.
- Respondents to surveys from most industry segments expressed concern over a potential future shortage of raw steel from which to manufacture materials and equipment. While there were no hard data available to the Council, the lack of investment in new domestic capacity and in replacement of obsolete, deteriorated facilities, together with the respondents' widespread identification of this as a potential problem, support major concern over adequacy of future raw steel capacity.

While major material, equipment, or manpower constraints to accelerated activity levels need not occur, the Council is concerned that potential constraints could develop in the long term if manufacturing, supply, and service firms perceive a future environment not conducive to expansion or foresee short supplies of basic resources essential to their operations. Such perceptions could cause these firms to delay or forego necessary capacity additions.

Recommendations

Based on findings and conclusions set forth in this report, the Council recommends the following measures to improve and expand the exploration, drilling, and production capabilities of the United States:

- The President, Congress, the Department of Energy, and other federal agencies should continue to promote the development of domestic energy resources, including the extraction of oil and gas. To this end, they should strive to establish a stable and predictable business climate conducive to accelerated expansion of investment, drilling activity, and support capacity. The creation of such an environment will entail the review of federal laws and regulations relating to leasing, price controls, taxation, and environmental preservation with the objective of enhancing capital formation and exploration and production activity.
- The federal government should create an environment which promotes the re-establishment of a strong and competitive domestic steel industry vital to the development of U.S. energy supplies and other critical areas of our nation's economy. This environment should encourage the expansion of domestic pipe mill capacity. Such will require the review of laws and regulations on steel imports, environmental controls, and taxation to allow generation of capital for modernization to improve the steel industry's productivity and competitiveness.

Summary

Background

The exploration and production sector of the petroleum industry is involved in the search, lease, drilling, development, and production of oil and gas resources, as well as in the ultimate abandonment of wells. This sector is composed of thousands of companies and individual operators supported by hundreds of manufacturers, suppliers, and service contractors. (A detailed description of the industry is presented in Appendix C.)

In the mid-1950's, the industry entered a period of decline in drilling activity which continued into the early 1970's. The growth in drilling activity beginning in 1972 placed increasing demands on suppliers of goods and services. Concern developed as to the adequacy of the materials and manpower necessary for the rapid growth in activity which had begun and was expected to continue if the nation's energy needs were to be met. As a result, the National Petroleum Council was requested in late 1973 to determine if the availability of materials, equipment, or manpower would constrain this growth in the near term (1974-1976). The Council, in its report issued in 1974, assumed drilling rig availability would be the primary constraint to increased activity, and tubular goods would possibly be a minor constraint in the early part of this period. The levels of near-term drilling activity considered in that study were in fact exceeded. There was a period in which it was difficult to secure needed tubulars and there were localized problems with drilling rig availability, but there is no evidence of any significant constraint to activity. The supply industry was able to respond to the increased demand; thus, areas of tightness have since abated even though activity levels continued to increase through 1978.

The most significant determinant of drilling activity levels is the profitability anticipated within the perceived future business climate. Most changes in activity growth rates since 1970 can be tied to events which altered expectations of profitability. The decline in drilling, which began in 1956, ended in 1972 in response to the increases in intrastate gas prices which began in 1971. The oil and gas price increases, which followed the 1973 oil embargo, stimulated rapid growth in drilling—especially infield drilling to increase recovery and production capacity in existing fields. Drilling growth slowed in 1975 as benefits of free market stripper oil prices and revisions of Base Production Control Levels were somewhat offset by the repeal of the depletion allowance.

Renewed rapid growth in 1976 and 1977 resulted from oil production incentives provided by upper tier oil prices, which continued incentives for infield drilling and for developing marginal reserves. Additionally, gas well drilling was stimulated by higher prices allowed for interstate gas sales by the Federal Power Commission. Confusion over future gas prices while the 1978 Natural Gas Policy Act was in the legislative and regulatory process and the decline in the real price (inflation adjusted) of crude oil (lower and upper tier) contributed to slower growth during 1978. A significant factor in the early 1979 drilling slump was producers' wait-and-see attitude resulting from uncertainties during the debate on oil price decontrol and windfall profits taxation. Other factors such as the discovery of reserves in new geologic provinces, environmental issues, and severity of winter weather have also influenced year-to-year trends in drilling activity, but anticipated profitability in the business climate has been the most significant.

There continues to be some concern that industry is approaching a physical limit to the level of activity. This has been especially evident during discussions of the need to improve incentives for domestic oil and gas production. There is some expressed doubt that the industry would, in fact, be able to expand activity if incentives were increased.

In requesting this study, the Department of Energy asked the Council to address whether and, if so, to what degree the availability of materials and manpower may constrain the acceleration of exploration and production activity.

Approach to the Study

The 1974 National Petroleum Council study, *Availability of Materials, Manpower and Equipment for the Exploration, Drilling and Production of Oil—1974-1976*, focused almost entirely on the near-term years indicated in the title. The approach utilized in the 1974 study was to establish an industry activity level by assuming that all available drilling rigs would be employed to their maximum capacity. Other industry segments were then tested for potential constraints at that activity level.

In discussing the request for the current study, the Department of Energy indicated that use of the methodology in the 1974 study would be acceptable, but asked for sensitivity analyses to be done for activity levels at other than the projection derived through that methodology. The desire for sensitivities appropriately reflects the practical impossibility in developing a single projection of activity which would, by itself, provide an adequate test for materials and manpower constraints. Any such projection is, by necessity, based on judgment; therefore, opinions as to the proper level would vary greatly. Any conclusions from the study would, consequently, be subject to challenge.

With this as background, the Council formulated an approach intended to minimize the difficulty in reaching broad agreement upon a single projection and one which potentially would provide more useful information to those using the results of the study. The approach employed was to segment the issue into two separate and somewhat independent areas of investigation.

- Projected capability of the manufacturing, supply, and services industries to support the petroleum industry in exploring for and developing domestic oil and gas resources. (Implicit in projecting the capacities of these industries was the assumption that there would be no significant change in political, regulatory, or business climate and that basic steel, energy, and other essential resources would not be constraints.)
- A projected range of possible industry drilling activity based on published and private forecasts and on judgments regarding factors which tend to increase or decrease activity levels.

These two projections were then compared to determine the extent to which industry activity levels might be constrained by the availability of materials or manpower.

Concurrent with but separate from the above effort, an examination was conducted of the impact of laws and regulations, and changes thereto, on future exploration and production activity and service and supply capability. As a matter of practicality, it was decided to limit this analysis to the area of federal laws and regulations. (A discussion of these impacts is presented in Appendix D.)

An early decision in the study effort was the desirability of conducting surveys to obtain data which would assist in analyzing the capacities of the individual segments of the manufacturing, supply, and service industries. It was also decided to use the survey approach to aid in identifying the impact of government regulations and the future business environment on activity levels. In order to obtain such information for both of these efforts, 34 questionnaires were prepared. In total, over a thousand exploration and production companies, associated manufacturing, supply, and service firms, banking organizations, and academic institutions received one or more of these questionnaires. These surveys were conducted throughout the first half of 1979 and thus the responses reflected perceptions at that time. The responses to these surveys were most helpful in preparing this report, and the Council wishes to acknowledge this cooperation and to thank the respondents for their time and thoughtful consideration of this matter.

The certified public accounting firms of Arthur Young & Company and Arthur Andersen & Co. were retained by the National Petroleum Council to receive and aggregate the responses of the various surveys. These firms were instructed to treat all responses in strictest confidence and release no identifiable individual respondent data. They were also instructed not to release any aggregated data element unless the responses of at least three organizations were included. Through these procedures, the public accounting firms assured that no identifiable individual respondent data would be made available to study participants or others, nor could such information be derived from the data presented.

Findings

Drilling Activity Outlook

An analysis of 23 independent forecasts of U.S. drilling activity by various service and supply industry, government, and financial institutions formed the basis for a projection of a range of possible drilling activity. This range (presented in Chapter One and hereafter referred to as *Outlook*) was based on the assumption that more favorable business conditions would prevail after 1978. The upper level of the possible activity range reflects growth in wells drilled at an average annual rate of about six percent per year from 1979 through 1981 and three percent per year from 1982 through 1990. The 1979-1981 rate is slightly less than the seven percent per year average compound growth from 1975 through 1978. However, because of the higher base activity level, projected average annual increases in wells in the 1979-1981 period (3,167) exceed the 1975-1978 average (3,133). By 1990, about 75,400 wells (a 55 percent increase from 1978) and 435 million feet of hole (an 88 percent increase from 1978) could be drilled, provided that a very favorable business environment could be sustained from 1979 forward.

The lower level of the activity range assumed less significant improvements and a slower rate of improvement in business conditions prevailing after 1978. Growth in drilling of almost two percent per year was projected for 1979-1981, and just over two percent per year for 1982 through 1990. Drilling activity in 1990 would increase to about 62,300 wells (a gain of 29 percent over 1978), and 366 million feet (up 58 percent over 1978).

This projected range of drilling activity, although attainable, is based on hypothetical improvements in business conditions for oil and gas exploration and development. Although many factors, including a long winter, affected drilling activity during 1979, actual drilling activity was below the lower level of the projected activity range due largely to the delay and uncertainty of improvements in producer profitability expectations. Decontrol of crude oil prices with resulting improved profitability expectations is expected to bring drilling into the projected possible activity range. However, continued significant improvements in exploration and production investment incentives will be required to achieve the upper level of the projected activity range.

Geological and Geophysical Services

Geological services are performed by petroleum geologists who seek and assess possible deposits of oil and gas by studying the structure, composition, and history of the earth's crust. This is a manpower-intensive, professional service for which few materials are required. Findings pertaining to geologists are discussed in the Manpower chapter of this report. (Chapter Seven).

The non-Communist world geophysical services industry is largely U.S.-based. In times of faltering domestic demand, history has demonstrated that excess domestic geophysical capacity moves rapidly to the international market. In the last two or three years, U.S. marine geophysical crew capacity has migrated to international waters as U.S. demand declined. A consistent domestic market is a key factor in assuring consistent availability of domestic capacity.

Geophysical activity increased in 1971 after 17 years of decline. During the decline period, geophysical activity in the United States, as measured by seismic crew months, fell to one-third of its peak activity. The Middle East oil embargo in 1973 was quickly followed by a rapid increase in U.S. geophysical activity during 1974. After a period of uncertainty during 1975 and 1976, activity accelerated to a growth rate of 21 percent per year in 1977 and 1978. With projected capacity, this growth rate is sustainable through 1981.

Exploratory drilling which results from geophysical prospecting is projected to grow during this period at a 4.5 percent compound rate. Therefore, geophysical services are not expected to limit drilling activity. However, two types of geophysical equipment are identified as potential but not probable constraints: vibratory sources and recording instruments. Temporary supply tightness can be relieved by rapid expansion of manufacturing capacity.

Wireline services (logging and perforating) are provided by a few major companies and are supplemented by a large number of smaller companies offering specialized services. Demand for wireline services is directly related to drilling activity. This industry has grown at a compound rate of about 10 percent in logging and perforating field units since 1970, and projected capability will sustain this growth through 1990. This is a substantially higher rate than the upper level of possible drilling activity discussed in the Outlook chapter of this report (*Outlook upper level possible*).

Drilling Equipment

The drilling equipment industry has the present capability and is expected to have continued capacity in the future to support domestic drilling along the Outlook upper range of possible activity levels. The ability to expand rapidly was demonstrated during the 1973-1978 period, when the total rig fleet grew by 54 percent (from 1,850 to 2,851) and the active rig count increased by 89 percent (from 1,194 to 2,259)—a compound growth rate of more than 13 percent. Projections of basic rig manufacturing capacity (dedicated to the U.S. market) exceed total projected upper level possible demands out to 1990 when activity could possibly exceed the 1978 level by more than 80 percent. A capability to further increase capacity by 25 percent in less than a year, and to double capacity in about two years, was indicated.

During the 1973-1978 period, mobile offshore rigs available in U.S. waters increased by 71 percent (from 78 to 134), while utilization increased from 73 to 92 percent. The total available fleet of 140 in U.S. waters at mid-1979 represented one-third of the world fleet. At that time, 23 units were under construction in U.S. yards, more than enough in number to supply upper level projected demands through 1981.

Adequate capacity is projected through 1981 for major auxiliary equipment: the drilling string (drill pipe, tool joints, drill collars, and bits), and pressure control equipment (blowout preventers and control systems). Except for drill pipe and drilling fluid additives, auxiliary equipment supply capacity could be expanded by 25 percent in 6 to 14 months, after 1981.

Drill pipe mill capacity is projected to be adequate to meet the upper level drilling activity through 1981, but a potential shortfall is indicated in 1985 and 1990 if exports continue at the historical rate of 40 percent. Projected domestic demand could be met in 1985 and 1990 by reducing exports, or by increasing U.S. mill capacity dedicated to drill pipe at the expense of casing and tubing production.

The supply of drilling fluid additives is a potential constraint to accelerated drilling activity. However, the industry projects capacity sufficient for upper level drilling activity to 1990. Three major products (barite, a weighting material; bentonite, a thickener; and lignosulfonate, a thinner) represent 95 percent of the tonnage and half of the dollar market for drilling fluid companies. The supply of barite is expected to be tight as new ore deposits become more difficult to find and produce. Barite imports, which were two percent of the supply in 1978, are projected to grow to seven percent in 1981 and 12 percent in 1990.

The current shortage of rail cars affects delivery of all drilling fluid additives and particularly bentonite, which is produced almost exclusively in Wyoming. The rail car shortage has contributed to long lead times for bentonite deliveries, and as a result, peak demand periods may be marked by spot shortages. Lignosulfonate, which is made from a byproduct of the paper industry, could become in short supply due to declining availability of the basic raw material.

Tubular Steel

The domestic steel industry is the most important source of oil country tubular goods (OCTG—casing, tubing, and drill pipe). Shipments of OCTG rose sharply in 1974 and 1975 with growing drilling activity and user inventory build-up, and slumped in 1976 as inventories were reduced. Shipments reached a high in early 1978 indicating an annual capacity above three million tons. An industry survey indicated plans to increase casing and tubing manufacturing capacity from 2.99 million to 3.33 million tons per year in the 1979-1981 period. Estimated imports rose from about seven percent of domestic consumption in 1974 to about 24 percent in 1978. The total tubular supply includes an estimated 300,000 tons per year from miscellaneous sources (such as reclaimed used pipe), which represent about 10 percent of the current supply. Exports historically have ranged from 100,000 to 150,000 tons.

Adequate supplies of OCTG are expected to be available through 1981. However, the projected upper level demand will be so close to the projected supply by 1981 that a significant user inventory build-up, a drop in import levels, and/or a large increase in exports could result in a tenuous supply/demand balance. Beyond 1981, upper level projected demand would exceed the projected supply by 100,000 tons in 1985 and one million tons in 1990 if the import/export balance remains relatively stable. Assuming the Outlook lower level projection of 1990 drilling activity, the demand would exceed supply by 190,000 tons.

The projected shortage might be remedied by one or more alternatives including: increased imports; decreased exports (only partially effective); construction of new tubular mills with a shifting of raw steel from other products; or expansion of raw steel supplies as well as additional tubular mill and finishing capacity.

The most secure and reliable supply of OCTG would result from expansion of domestic steel and tubular production capacity. In order for such expansion to occur, the steel industry will need clear, predictable incentives to proceed. Without a reasonably predictable market, the industry cannot justify the heavy capital investment required for significant capacity expansion.

Production Equipment

Manufacturing capacity for oil and gas production equipment is expected to be sufficient to support the Outlook upper level of possible domestic drilling activity. Capacity increases in the production equipment industry during the 1973-1978 period of accelerated drilling activity clearly demonstrate that, given strong product demand, the production equipment industry will meet, or exceed, supply requirements. Since 1973, this industry has expanded capacity at a compound growth rate of 10 percent per year.

In the short term (1979-1981), the production equipment industry plans to increase manufacturing capacity by four to seven percent per year, paralleling the upper level of the possible drilling activity projection. Plans for expansion of manufacturing capacity beyond 1981 are less well defined. Because of uncertainties in long-term product demand, many manufacturers made conservative projections of their long-range capacity additions (35 to 40 percent indicated they currently have no plans for expansion in the 1982-1990 time period). Despite this conservatism, adequate growth appears likely; further growth in capacity can be expected if incentives provided from additional drilling and production activity warrant it.

Yard capacity for fabricating offshore platforms nearly tripled from 157,000 tons in 1973 to 439,000 tons in 1978, although in 1978, utilization of that capacity was only 65 percent. Concurrent with this, total derrick barge capacity (for platform installation) was being utilized at only 45 to 50 percent. By 1990, projected fabrication capacity will be 617,000 tons, with sufficient derrick barge capacity to install 220 platforms per year.

Several industry segments manufacture equipment not intended exclusively for oilfield use. This includes electrical equipment, prime movers (motors/engines), and pumps and compressors. Although it is not anticipated that these industry segments will present any constraints to petroleum industry activity, increased costs for such things as providing additional engine emission controls could reduce the capital available for future plant expansion.

Directly related industry segments, such as wellheads, surface production facilities, and artificial lift equipment, are projected to grow at annual rates of four to 12 percent from 1979-1981, and three to seven percent during 1982-1990.

Key potential constraints, in addition to those discussed in the Conclusions section of this report, include the potential shortages of alloys containing chromium and cobalt, long lead times for machine tools, and shortages of energy needed for equipment manufacture.

Well Servicing

Of the many service and supply functions which make up the well servicing industry, four categories are examined in this section: well servicing rigs, cementing and stimulation services, specialty tools and services, and air and marine transportation. Other functions traditionally associated with this industry are examined in other sections of this report. Present capacity plus planned additions will be sufficient to support the projected upper level drilling activity and the production maintenance demands of a growing number of active oil and gas wells.

Following the oil embargo of 1973, the demand for well servicing rigs for new well completion work and for improvement of the production rates of old wells caused an increase in rig population. Escalating rig deliveries, which in 1978 were three times the 1974 deliveries, resulted in a rig growth rate of about four and one-half percent per year while the demand increased four percent per year. The mounting oversupply reduced the utilization rate from an estimated 91 percent in 1974 to 77 percent of available rigs in 1978. If present and planned manufacturing capacity is utilized, the available rig count is estimated to increase by a range of six to eight percent per year to 1981, and four to five percent thereafter to 1990. This nearly equals the projected upper level drilling activity and exceeds projected two and one-half to five percent per year additions to the active oil and gas well count.

Cementing and stimulation service capacity is very sensitive to demand and can respond rapidly. Since 1975, fracturing and cementing services have grown at a 15 to 20 percent annual rate. In the short term, growth is projected to continue at a reduced rate, but could be expanded to a higher level with one year lead time. The current shortage of rail cars is a potential constraint which can cause spot shortages of the cement and sand used in large quantities by these services.

The production of specialty tools and services has expanded nine to 12 percent per year in recent years and is projected to continue growing at a high rate to meet demands.

Land and marine transportation vehicles and vessels are currently in surplus. A slight shortage of helicopters on the Gulf Coast has been relieved by the movement of equipment from other areas and the ample supply of marine craft. Economic incentives are expected to bring more aircraft into this service. This is an example of the spot shortages which will occur from time to time as mentioned in the Conclusions section of this report.

Manpower

Exploration and production companies responding to surveys expect that the availability of professional personnel will have a growing impact on the ability to expand rapidly during the 1980-1985 period; less than half expect the impact will be large. Expanding activities under the most favorable projected business climate would temporarily tighten the supply of professional personnel but would not restrict oil and gas companies in seeking and developing investment opportunities. The demand for professionals will be met by rapidly increased enrollment in the critical disciplines—geology and petroleum engineering. The extreme cyclic demand for these graduates imposes serious problems on the universities and on the young people selecting a career.

No circumstances can be foreseen that could produce a manpower constraint to the expansion of drilling and well servicing activities. The problem of cyclic demand is related to government regulation of exploration and production. The greatest need is for federal policies to relieve uncertainties in the future and thus stabilize demand.

The demand for skilled labor in other service and supply businesses is manageable, but suffers from the same cyclic demand as does the drilling and well servicing business.

The availability of skilled workers is a recurring problem for all industry sectors, but it is being managed through intensive recruiting and training programs by industry.

Chapter One
Drilling Activity Outlook

Introduction

The projected range of possible industry activity used in this study was developed from an analysis of 23 forecasts of drilling activity made by various oilfield service and supply companies, consultants, and financial organizations. The perspective of exploration and production companies was added by the judgment of the Subcommittee. Although 34 sources of forecasts were identified for consideration, 11 were excluded: two because information was not anticipated to be available in time, and nine because they either duplicated other forecasts or did not develop projections of the parameters in which the Subcommittee was interested. Of the 23 studied in detail, three forecast wells only, six forecast footage only, and 14 forecast both wells and footage so that average well depth could be calculated. Appendix E contains a bibliography of these studies. Many of these forecasts have been published, but several were considered proprietary by the authors and were available only for this study. For that reason, the identity of the individual forecasts has been masked by the assignment of an arbitrary number. Subsequent discussion will refer to the forecasts by number only.

The objective in analyzing the forecasts was to understand the assumptions and methods used, and the principal factors which controlled forecast levels. Some reports were available which provided definitive information. However, in order to obtain a complete and accurate understanding of the forecast regardless of whether reports were available, extensive interviews were conducted with the authors, who were very cooperative. A summary of the analysis of each forecast is provided in Appendix E.

Projected wells and footage from the 23 sources are plotted in Figures 1 and 2. Due to the differing vintage of forecasts, the projections were adjusted upward or downward, as necessary, to a common starting point, estimated to be the 1978 final industry drilling activity. Percentage growth rates indicated by the individual forecasts were held constant in making this shift.

Projections

Based on these 23 forecasts, a projected range of possible activity levels was developed. Although somewhat higher or lower levels could occur, for purposes of this study the projections provided a sufficiently broad range against which future materials and manpower availability could be tested. The projections of wells, footage, and average depth are shown in Figures 3, 4, and 5, respectively, and tabulated in Table 1.

Upper Level

The upper level of the possible activity range reflects growth in wells drilled at an average annual rate of about six percent per year from 1979 through 1981, and three percent per year from 1982 through 1990. The 1979-1981 rate is slightly less than the seven percent per year average compound growth from 1975 through 1978. However, because of the higher base activity level, projected average annual increases in wells in the 1979-1981 period (3,167) exceed the 1975-1978 average

(3,133). By 1990, about 75,400 wells (a 55 percent increase from 1978) and 435 million feet of hole (an 88 percent increase from 1978) could be drilled, provided that a very favorable business environment can be sustained from 1979 forward.

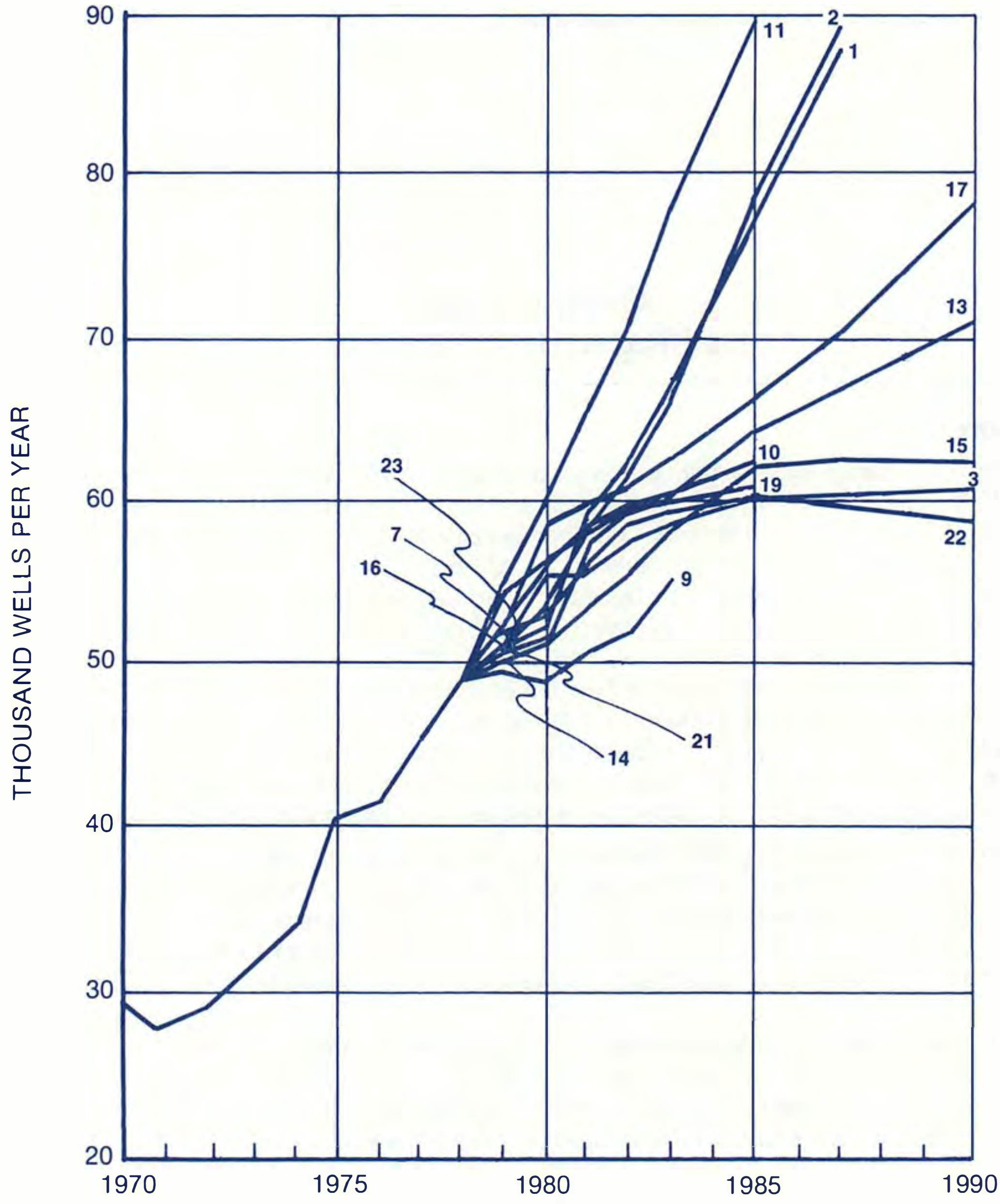

Figure 1. Drilling Forecasts (Projected Wells Adjusted to 1978 Actual).

Lower Level

The lower level reflects a growth in drilling of almost two percent per year for 1979-1981 and just over two percent per year for 1982 through 1990. Driling activity in 1990 would increase to about 62,300 wells (a gain of 29 percent over 1978) and 366 million feet (up 58 percent over 1978).

Assumptions

The Council's projections of the range of possible activity assumed, even at the lower level, more favorable business conditions than those actually existing at the beginning of 1979. However, because of a recognized inability to predict accurately the time at which business conditions might be established which could cause the projected activity increases and in order to produce a more stringent test of materials and manpower availability, activity levels were projected to increase from the beginning of 1979. The controlling business conditions for the upper and lower levels of the projected possible range of activity were assumed as follows.

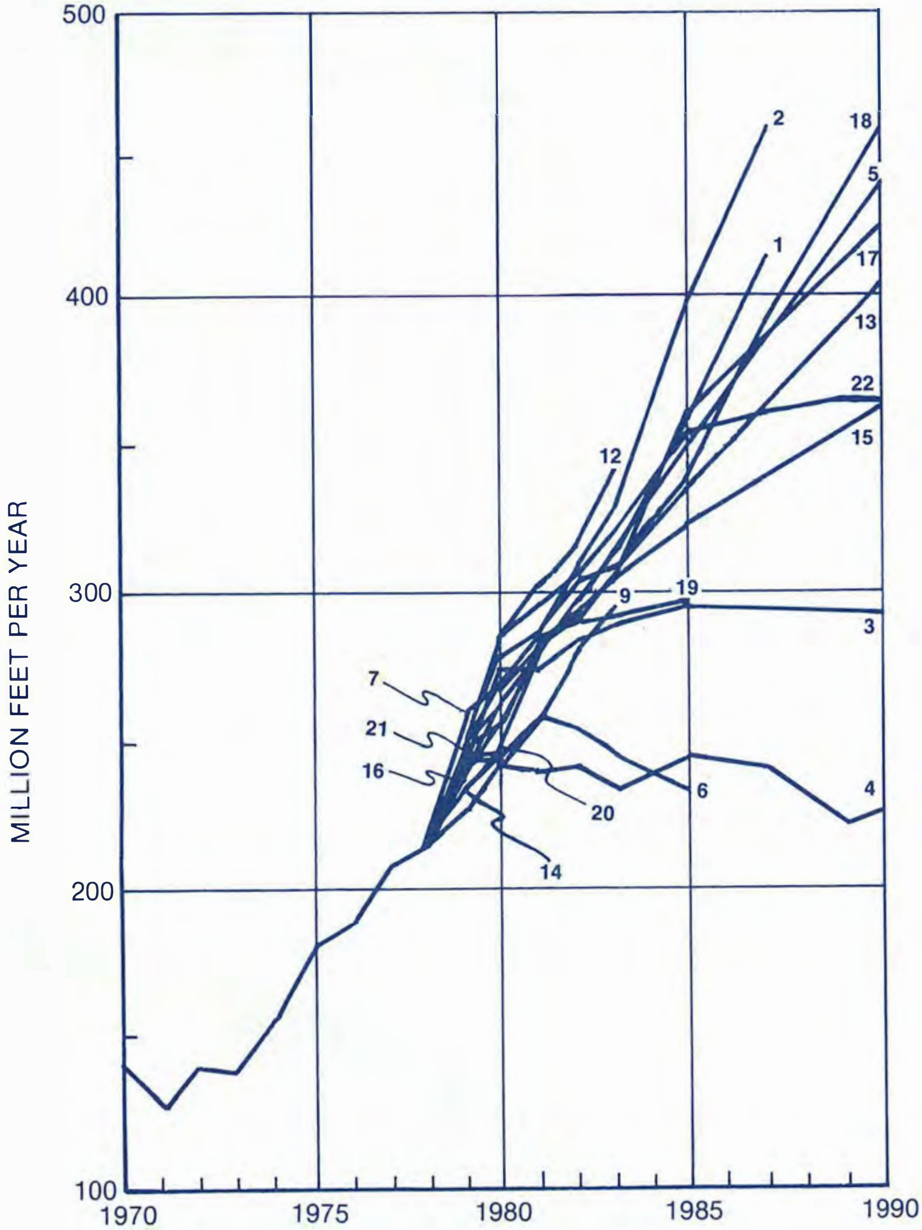

Figure 2. Drilling Forecasts (Projected Footage Adjusted to 1978 Actual).

Upper Level

The upper level of the possible activity range could be achieved if very favorable business conditions were established early in 1979. Delays in decisions to improve the current environment will generally be reflected in lower activity levels. In such a favorable environment, increasing real prices for crude oil and natural gas and tax incentives for enhanced oil recovery projects provide adequate profit margins for substantial efforts to explore for new reserves and to maximize recovery from existing and new fields. Access to public lands on the Outer Continental Shelf (OCS) and in inland areas must continue to be at least as good as in the past.

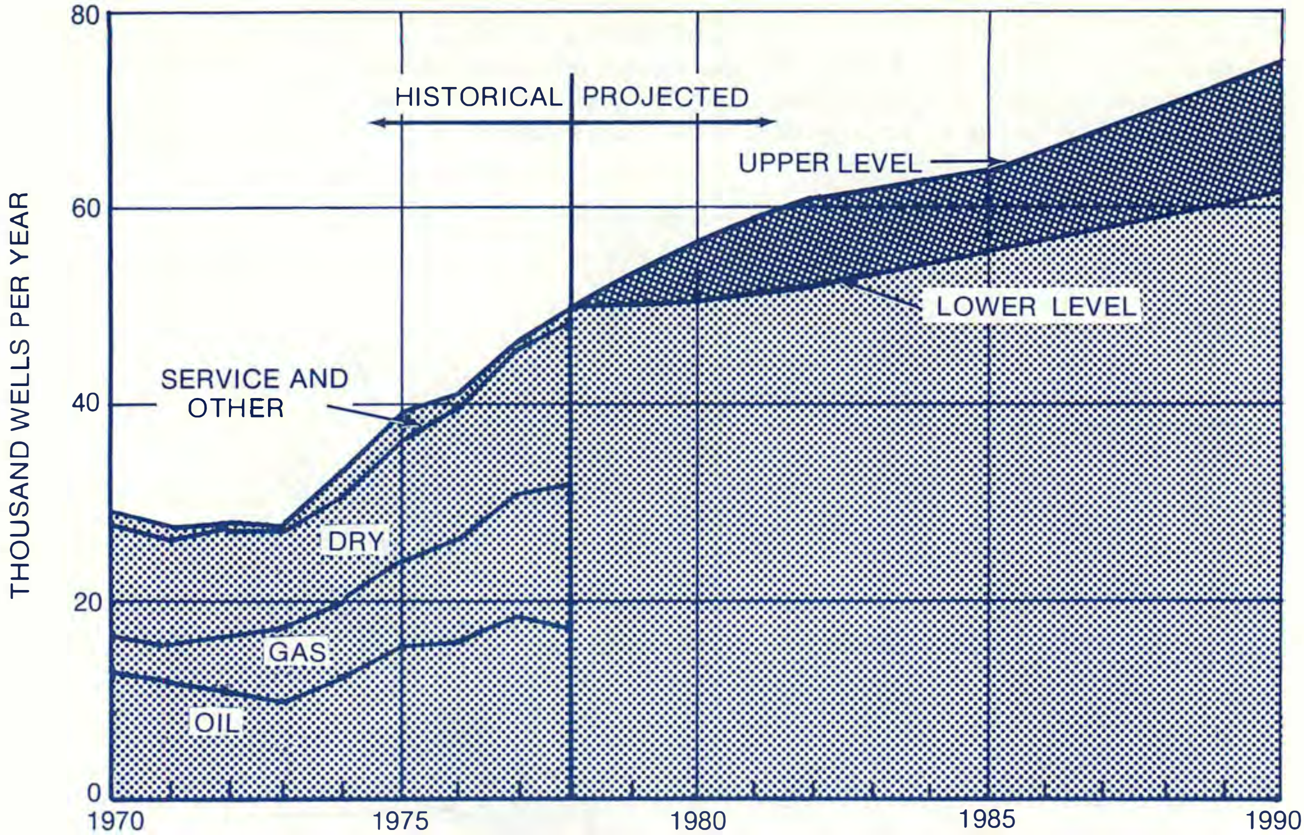

Figure 3. Historical and Projected Range of Possible U.S. Drilling Activity — Wells.

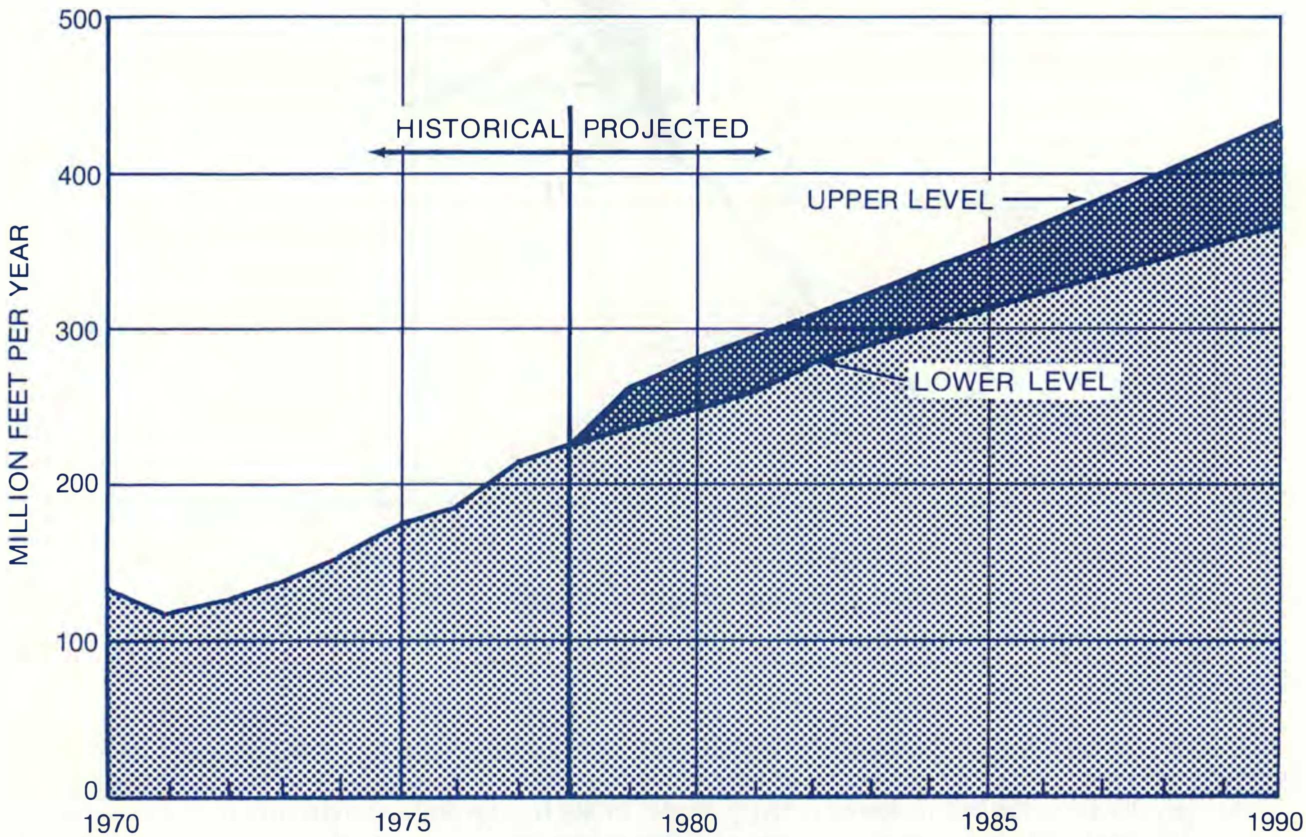

Figure 4. Historical and Projected Range of Possible U.S. Drilling Activity — Footage.

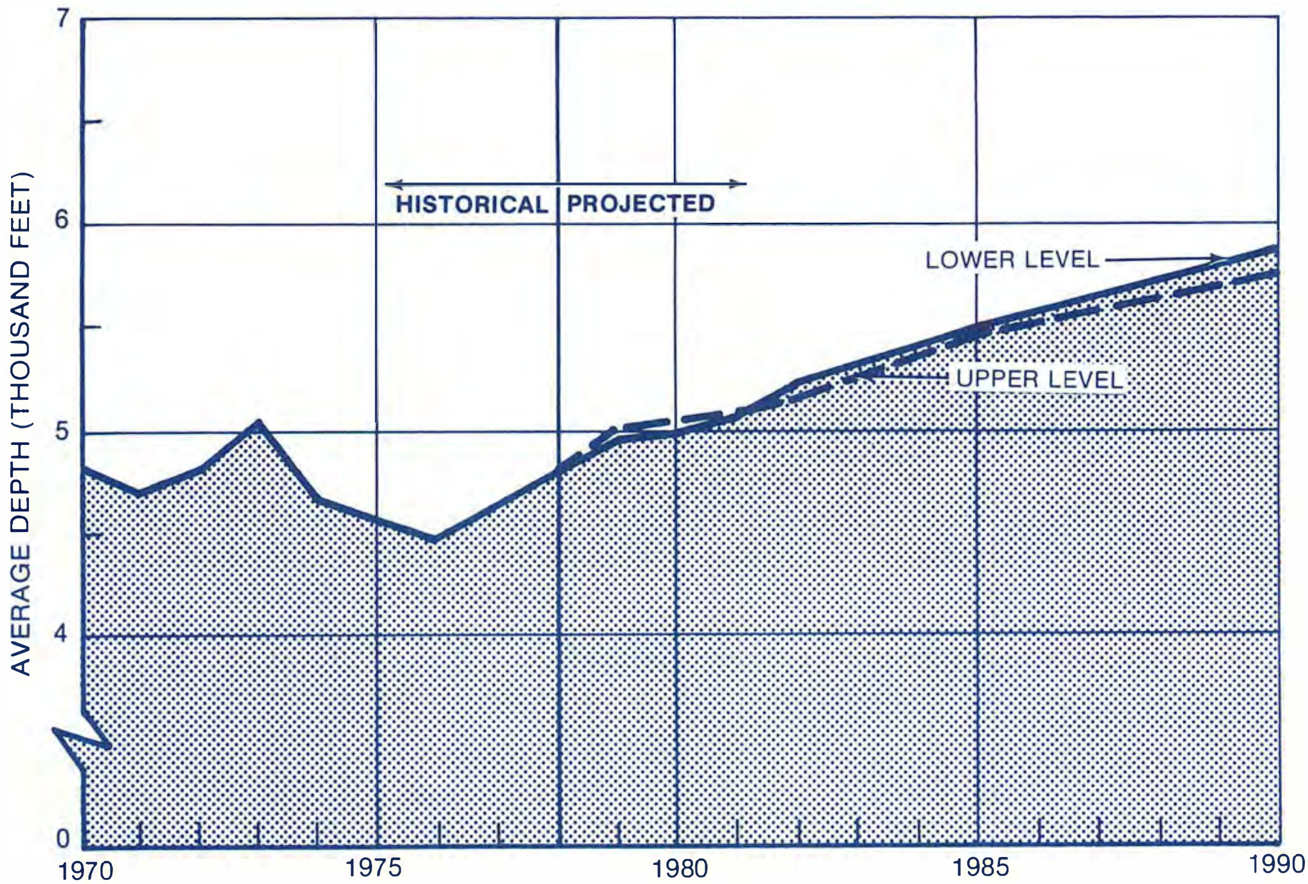

Figure 5. Historical and Projected Range of Possiblε U.S. Drilling Activity — Average Depth.

TABLE 1

HISTORICAL AND PROJECTED RANGE OF POSSIBLE DRILLING ACTIVITY

	Upper Level			Lower Level		
	Wells (thousands)	Footage (millions)	Average Well Depth (feet)	Well (thousands)	Footage (millions)	Average Well Depth (feet)
Historical*						
1973	27.6	139	5,034			
1974	32.9	153	4,656			
1975	39.1	179	4,566			
1976	41.5	185	4,471			
1977	46.5	215	4,626			
1978	48.5	231	4,771			
Projected						
1979	52.0	261	5,011	49.1	243	4,949
1980	55.3	279	5,038	49.7	248	4,990
1981	57.8	293	5,068	50.8	256	5,039
1982	60.2	310	5,150	52.3	272	5,200
1985	64.6	353	5,464	56.8	312	5,493
1990†	75.4(70.8)	435(415)	5,769(5,862)	62.3(60.2)	366(357)	5,875(5,930)

* Historical drilling statistics from American Petroleum Institute.
† ( ) excludes enhanced oil recovery drilling.

Infield drilling in mature fields is expected to continue at high levels through the 1980's in response to increases in lower tier prices to free market levels no later than the mid-1980's. By that time, diminishing opportunities for infield drilling in the inland areas of the lower 48 states may result in slower growth in drilling activity. Other factors contributing to slowing growth rates include increasing well depths, increasing allocation of available funds from development to exploration activity, and increasing activity in frontier areas where fewer, more prolific wells will be required for economic development.

Increasing growth rates during the late 1980's could occur if the proper combination of oil prices, favorable tax treatment, and technological developments produce a substantial incentive for implementing enhanced oil recovery (EOR) processes. The December 1976 report of the NPC study on enhanced oil recovery projected that up to 4,600 new wells per year (six percent of total drilled) could be required by 1990 for EOR projects in this type of favorable business environment.

Improvements in drilling technology are expected to occur gradually, but rapidly enough to maintain rig performance at about 1978 levels and to prevent excessive cost increases despite the trends of increasing well depth and activity in hostile frontier areas. If drilling for gas from unconventional gas sources becomes feasible during the next decade, higher activity levels could result. No drilling for unconventional gas resources has been included in this projection.

Lower Level

Because the purpose of this study is to determine if a shortage of materials and manpower could become a constraint to activity, the potential has not been evaluated for flat or reduced activity levels which could result from an unfavorable business climate. The lower limit of the possible activity range assumes some improvement in the early 1979 business environment. The primary difference between the business environments producing the lower level of the activity range and those assumed for the upper level is that improvement comes slower and to a lesser degree. Significant improvements are deferred into the mid-1980's. The very slow growth projected through 1981 results primarily from the combined effects of the temporary excess in natural gas deliverability and the uncertainty the 1978 Natural Gas Policy Act has brought to pre-1985 gas prices. Increased growth projected after 1981 results from assumed improved crude oil prices, and after 1985 from decontrol of new natural gas prices.

The gradual end of growth in drilling activity is anticipated because of declining infield drilling in mature inland areas, increasing average well depths, and reduced access to public lands, both onshore and offshore. Enhanced oil recovery activity remains insignificant because lower prices and less favorable tax treatment result in slower and less extensive initiation of EOR projects. The December 1976 NPC report, *Enhanced Oil Recovery*, projected that only 2,100 wells per year (three percent of the total) would be drilled by 1990. As in the upper level case, no drilling for gas from unconventional sources was included.

Methodology

On the basis of these descriptions and our understanding of the forecasts, projections 1, 2, 3, 4, 6, and 11 (shown on Figures 1 and 2) were judged to have characteristics that place them outside the possible range of industry activity levels.

Projections of possible industry drilling activity levels are shown in Figures 3, 4, and 5, for wells, footage, and average well depth, respectively. Data from these figures are shown in tabular form in Table 1. Other than the forecasts analyzed, factors considered included: the historical activity build-up from 1973 to 1978; trends in infield development drilling to achieve increases in production and recovery from existing fields; and the potential impact of additional wells needed for enhanced oil recovery projects which could become significant by the late 1980's.

In order to relate drilling activity to oil country tubular goods consumption considering the types and depths of wells drilled, drilling by well depth category was projected through 1981 for each NPC geographical region (as defined in Appendix E). This was done by projection of historic trends in the percentage of total U.S. wells drilled in each region. Consideration was also given to changes in activity as reported in trade journals, and possible responses to a shift in the business environment which would encourage upper level activity. These regional projections by well depth range, and a breakdown of projected upper level activity into oil and gas development wells, exploration wells, and service and other wells, are described in Appendix E.

The regional projections of footage by depth were aggregated so they could be compared to the projections of U.S. total activity previously described. Because the two methods produced very similar footage forecasts, the projected upper level of the possible range of activity was judged to provide a reasonable basis for testing the availability of materials and manpower. However, the range of activity is not a forecast of probable activity and should not be used in making investment decisions.

The achievement of high levels of activity in 1985 and 1990 will depend somewhat on activity levels in the early 1980's. Actual 1979 activity levels were slightly below the lower level of the projected range of activity. If adequate producer incentives and public lands access are assured from 1980 forward, the demand for oil and gas drilling could very nearly reach the upper level by the late 1980's.

Chapter Two
Geological and Geophysical Services

Introduction

This chapter covers findings and conclusions regarding the adequacy of the materials and equipment required by geological and geophysical services to support maximum projected well drilling and workover activity for the periods 1979-1981 and 1985-1990. The projected adequacy of manpower is reported in a separate chapter. Industry services covered here are geological, geophysical, and wireline.

Geological Services

These services are performed by petroleum geologists who seek and assess possible deposits of oil and gas by studying the structure, composition, and history of the earth's crust. This is a manpower-intensive, professional service for which few materials are required.

Geophysical Services

Geophysical measurements taken at the surface provide the major clues for locating potential subsurface reservoirs which may contain hydrocarbons. Measurement of changes in the earth's magnetic and gravity fields provides data which may broadly define potentially prospective areas, but the major geophysical tool used in oil exploration is the reflection seismograph. With this tool, a physical pulse or vibration is created at or near the surface, producing a wavefront of sonic energy which travels through the subsurface and is partially reflected back to the surface each time the wavefront encounters a discontinuity such as a boundary between two rock layers. This reflected energy is picked up at the surface by extremely sensitive microphones which convert the sonic energy into electrical energy that is then amplified to produce usable signals. The seismograph records these signals as a function of time from the instant the pulse is created, and it measures the sonic wave travel time from the surface to one or more reflecting discontinuities within the subsurface and back to the surface again. Once the two-way travel time and the average velocity of sound through the subsurface are determined by making measurements at many points, the depth of the discontinuity can be calculated. With these data a contour map of the subsurface is produced from which the most likely locations of trapped hydrocarbons can be identified.

This is an oversimplified description of a complex process, with a rapidly developing sophisticated technology. It includes digital recording of data and computer processing to extract the usable signals from background seismic noise or extraneous signals. Because of the advancing technology, the seismic survey, which historically has been an exploration tool, is now being used in field development and is expected to be utilized more broadly in reservoir engineering analysis.

The free world geophysical services industry is largely U.S.-based, with a preference for U.S. operations when other incentives are equal. In times of faltering domestic demand, history has demonstrated that excess domestic geophysical capacity moves rapidly to the international market. In the last two or three years, U.S. marine geophysical crew capacity migrated to international waters as

U.S. demand declined in the face of public indecision and confusion over how, when, and where to develop the Outer Continental Shelf. A consistent domestic market is a key factor in assuring consistent availability of domestic capacity.

After 17 years, during which period geophysical activity in the United States as measured by seismic crew months declined to one-third of its peak activity, a turnaround began in 1971 (Figure 6). The oil embargo in 1973 was quickly followed by a rapid increase in geophysical activity during 1974; then, with the removal of the percentage depletion allowance and the confusion over domestic energy policy, activity again sharply declined at a time when exploration and development of new oil and gas supplies were very critical to the nation's future. However, as shown in Figure 6, this temporary decline was reversed in 1976. From then through 1978, U.S. geophysical activity grew at an average rate of 21 percent per year, a growth rate which is continuing in 1979 after a slowdown early in the year resulting from bad winter weather.

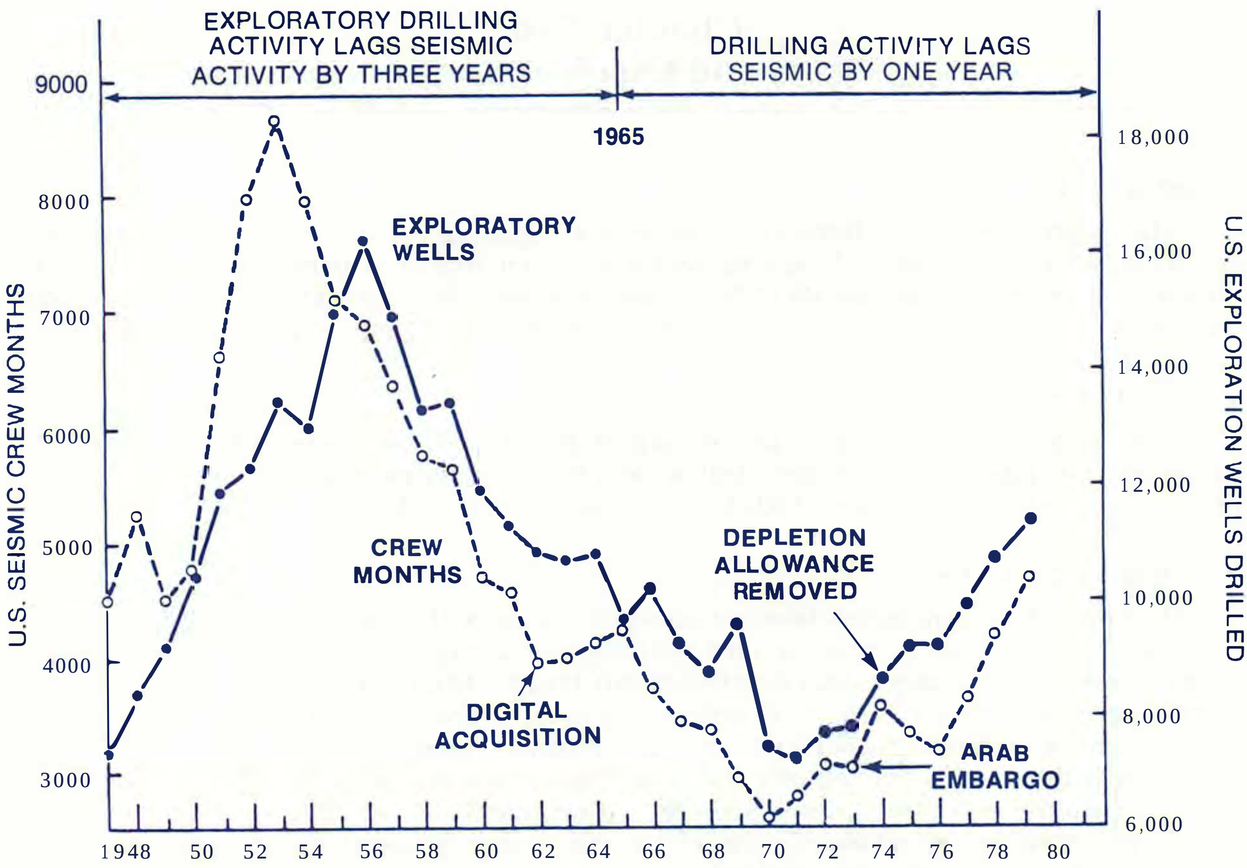

Figure 6. Correlation of Seismic and Drilling Activity, 1948-1979.

Wireline Services

The well logging industry provides mobile service units to lower probes and other devices into boreholes to make direct or indirect physical measurements or to perform mechanical services. Measurements taken by the sensitive probes relate directly or indirectly to properties of rocks which the geologist or reservoir engineer can use to evaluate the hydrocarbon location and content within the rocks surrounding the well bore. These measurements are critical to the evaluation and completion of each well drilled and to the evaluation and maintenance of each reservoir discovered and developed. Mechanical services include the perforation of well casing and setting plugs and packers within the hole. These are provided largely by six major service companies, supplemented by a large number of smaller, more specialized firms.

Analysis and Results

The growth potential of these services is substantially greater than the approximate six percent annual increase projected as the Outlook upper limit for drilling activity. Geophysical activity as measured by seismic crew months grew at an average annual rate of 21 percent from 1976 through 1978. Continued growth at these rates could be sustained through 1981. The wireline services industry has grown about 10 percent yearly since 1970 and should be able to sustain this through 1990 (Appendix F).

Two types of geophysical equipment were identified as potential but not probable constraints to growth: vibratory sources and geophysical recording equipment.

Vibratory Sources

Most of the world's vibratory sources are produced by three U.S. manufacturers, with a few additional units from a German supplier. Prior to 1977, U.S. manufacturers produced an average of 200 machines per year with the capacity to produce 300 units annually. Production in 1978 rose to 315 units, 95 of which were to fill large export orders, principally from the USSR and the People's Republic of China (Table 2). A December 1978 survey of the U.S. manufacturers revealed that a 25 percent expansion of production capacity is being planned and will allow the U.S. industry to meet growing foreign demand while continuing to deliver 200 or more units per year to the domestic market. This rate of domestic deliveries is expected to be sufficient to sustain a 20 to 25 percent annual growth rate through 1981 (Figure 7). If the industry continues to be profitable and factors affecting demand are reasonably predictable, further expansions can be expected if required.

In general, vibrator manufacturing capacity can be added with roughly the same lead time (8-12 months) required to produce critical parts and pieces used in the vibrator—such as engines and axles manufactured by external suppliers. Thus lead times can reasonably be expected to hold at around 12 months, about the same as experienced in the 1977-1979 period. In any event, alternatives for use of other seismic energy sources (dynamite, etc.) suggest that no severe constraint would result.

TABLE 2

VIBRATOR PRODUCTION DISTRIBUTION

	1978	1979	1980	1981	1982
Domestic	220	180	190	200	225
Non-Communist International		95	105	110	100
Communist Group	95	75	80	90	100
Total	**315**	**350**	**375**	**400**	**425**

Geophysical Recording Equipment

Seismic recording instruments are provided principally by four U.S. manufacturers and a French company.

The demand for seismic recording instruments is a function of industry growth, but it is also strongly impacted by technological developments which cause existing instrumentation to become obsolete or less desirable. Current rapid rates of technological development suggest that an accelerated rate of obsolescence and replacement will exist in the period 1981-1982. Current instrument production capacity, as determined from a 1977 study by one of the manufacturers, would allow all crews in the world to be brought up to 1978 state-of-the-art by 1981, if that were required. However, it is estimated that the actual rate of replacement will be much lower (50 instead of 100 percent) and that excess manufacturing capacity will continue to be available within probable limits of growth (Figure 8).

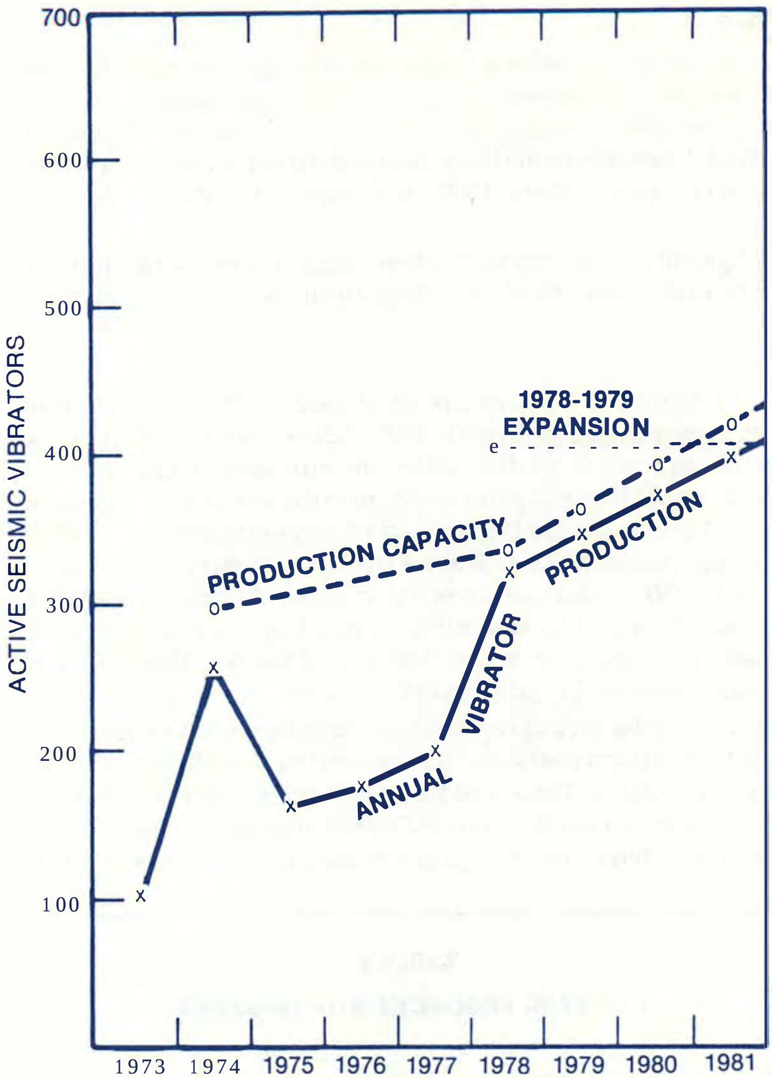

Figure 7. Seismic Vibrator Annual Production Growth Requirements, Facilities Expansion, 1973-1981.

As the state-of-the-art continues to advance, there is no doubt that any excess capacity beyond 1981 will tend to be diverted to another round of equipment replacement. In the unlikely event that the demand for new instrumentation exceed capacity, equipment scheduled for replacement will be kept in service for a longer time; therefore, it is likely that no instrumentation constraint will exist.

Tight supplies of diesel fuel and gasoline for vehicles and ships could, in the extreme, impede growth. However, it is believed that, in any serious fuel shortage, high priority allocations would be given to industries exploring for and developing oil and gas reserves.

Conclusion

The geological, geophysical, and wireline services industries will be able to grow to meet the projected upper levels of drilling activity in a way that will avoid constraint from this sector on oil and gas exploration and development.

Assumptions

The foregoing findings and conclusions assume:

- Reasonably normal lead times for companies to respond to projected increases in demand
- Adequate priority for companies to secure materials and supplies that are in critical supply when needed (e.g., diesel fuel).

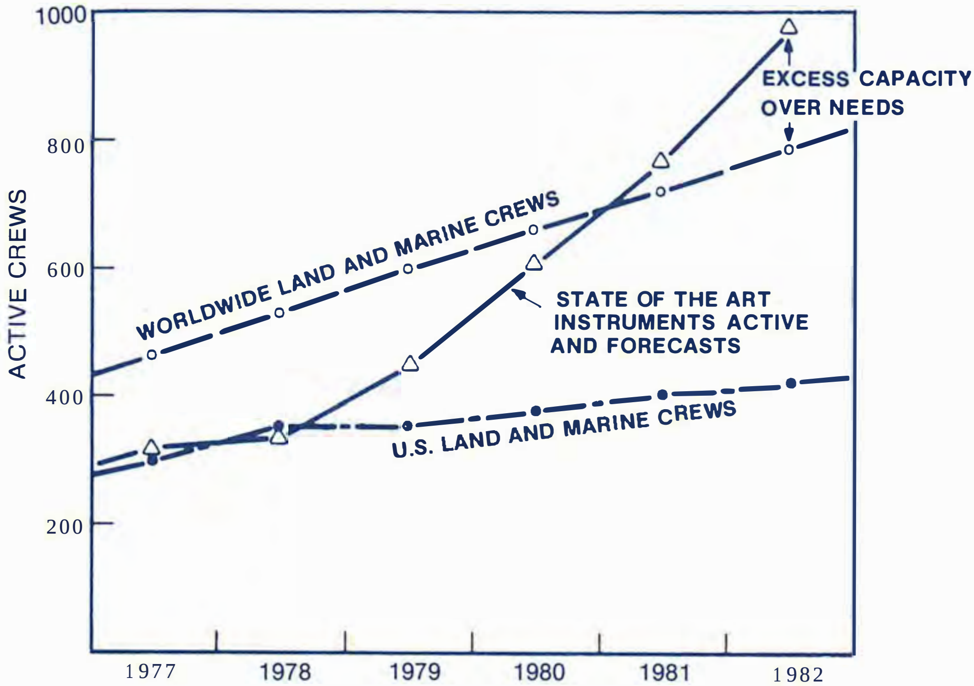

Figure 8. Acquisition Instrumentation Growth
and Capacity, 1977-1982.

Chapter Three
Drilling Equipment

Introduction

A rotary drilling rig may be thought of as a portable factory, designed to drill a hole to particular geological formations and wall the hole with steel pipe and cement with the objective of exploring for and developing oil and gas fields. Except for some specialized items such as pressure control systems, the same kind of drilling machinery is used offshore as on land. The offshore rig support may be an artificial island, a fixed structure, or a mobile unit. The equipment used and the drilling process are described in Appendix C.

For the 1974 NPC study, *Availability of Materials, Manpower and Equipment for Exploration, Drilling and Production, 1974-1976*, the shortage of drilling rig availability was assumed to be the primary constraint to increased activity. Wells and footage to be drilled were calculated from projected rig availability. For the current study, selected manufacturers of drilling equipment and drilling fluid additives were surveyed for existing capacity, planned expansion through 1981, and potential for further expansion out to 1990. Aggregated capacity data were compared for adequacy with the demand calculated, based on the Outlook upper limit possible range of activity.

Capacity data were obtained by surveying manufacturers and suppliers of equipment and materials by questionnaires in six categories (see Appendix G for summary of questionnaire responses):

- Drilling rigs
- Drill pipe
- Tool joints
- Drill collars
- Pressure control equipment
- Drilling fluids.

In addition to capacity projections, each respondent was asked to identify potential constraints.

Mobile offshore drilling unit data were obtained from the magazine *Offshore*. Drill pipe data were coordinated with those in the Tubular Steel chapter of this report. The drill bit supply was estimated independently and capacity expansion was based on announced plans.

Analysis and Results

Drilling Rigs

The total rig fleet demand is a function of footage to be drilled, rig performance (feet drilled per year), and percent utilization. The annual demand for new rigs is the sum of net additions and replacements due to attrition. Replacements are expected to increase to four percent per year from the historical rate of two percent, because many aged rigs have been reactivated since 1973. U.S. drilling activity history and projected demand is shown in Table 3.

TABLE 3

U.S. DRILLING RIGS

	Feet Drilled (millions)*	Active Rigs (Hughes)	Feet Per Rig (thousands)	Total Rigs (Reed)	Percent Utilization	Net Fleet Additions	Attrition§	New Rigs Total Demand
Historical								
1973	139	1,194	116	1,850	65			
1974	153	1,472	104	1,894	78	44		
1975	179	1,660	108	2,028	82	134		
1976	185	1,658	112	2,204	75	176		
1977	215	2,001	107	2,482	81	278		
1978	231	2,259	102	2,851	79	369	57	426
Projected								
		¶		**				
1979	261	2,486	105	3,182	78	331	127	458
1980	279	2,657	105	3,406	78	224	136	360
1981	293	2,790	105	3,577	78	171	143	314
1985	353	3,362	105	4,310	78	170	172	342
1990	435†	4,143	105	5,311	78	207	212	419

* Historical footage as reported by API. Projected footage is Outlook upper level possible.
† Includes 20 million feet of enhanced oil recovery drilling.
§ Projected attrition—4 percent or double 1978 experience.
¶ Calculated at 105,000 feet per rig. Variations from year to year in calculated rig performance are due to carryover to the following year of a substantial amount of footage reported late to API. The 5-year average performance, 1974-1978, was above 106,000 feet per rig year.
**Calculated at 78 percent utilization beginning in 1980. The Reed count was 3,182 in 1979.

Net additions to the rig fleet currently total nearly 350 per year. It was calculated, based on the demand of the upper level possible drilling outlook, that the net additions required would decline to below 200 per year in the early 1980's. Under the impetus of possible enhanced oil recovery drilling after 1985, net additions are projected to climb back to about 200 per year. Total new rig demand with upper level possible activity, stepped-up enhanced oil recovery drilling in the late 1980's, and four percent attrition (average life of 25 years) would decline from the 1978-1979 estimated demand of more than 400 per year to nearly 300 in 1981 and then climb to above 400 before 1990. The estimated four percent attrition rate does not include the potential impact on the equipment supply of a probable significant demand for replacement and spare parts for rig components.

The aggregated results of a capacity survey of U.S. drilling rig manufacturers are shown in Appendix G. Respondents' capacity projections totals are compared in Table 4 with projected demand from Table 3.

The capacity figures show the industry's ability to respond rapidly to demand. Most manufacturers build both drilling rigs and well servicing rigs in the same facility. The flexibility to build either allows a commitment of capacity to current demand, which accounts for a projected reduction from 1979 to 1980. The reported excess capacity of respondents dedicated to the United States beginning in 1979 indicates that drilling rigs will not be a constraint to projected upper level possible drilling activity. Respondents indicated the capability to further increase capacity by 25 percent in less than a year and to double it in about two years.

Mobile Offshore Rigs

Mobile offshore drilling rigs are used primarily in exploratory drilling. The four principal types are jack-up, semi-submersible, submersible, and drill ship. All types are usually self-contained and are designed to provide a stable and safe support for the drilling machinery and facilities for supplies and personnel. The types are further described in Appendix C.

Mobile offshore rigs available worldwide almost doubled during the five years of 1972 through 1977, resulting in a drop in utilization rate from 96 percent in 1974 to 81 percent in 1976, as shown in Table 5.

TABLE 4

U.S. DRILLING RIGS
PROJECTED SUPPLY AND DEMAND

	Manufacturing Capacity *			
	Total	Dedicated To U.S.	High Level Demand	U.S. Demand as Percentage of Capacity Dedicated to U.S.
Historical				
1974	157†			
1978	490	371	426	115
Projected				
1979	730	523	458	88
1980	706	491	355	72
1981	706	476	314	66
1985			342	
1990			419	

* Survey response.
† *Oil and Gas Journal*, April 21, 1975. The 1974 NPC report projected 135 deliveries in 1974.

TABLE 5

OFFSHORE MOBILE RIG AVAILABILITY

	Worldwide				U.S. Waters			
	Available Rigs				Available Rigs			
Year End	Units	Change	Active Rigs *	Percent Utilization	Units	Change	Active Rigs *	Percent Utilization
1972	212	—	173	82	70	—	51	73
1973	236	+ 24	207	88	78	+ 8	57	73
1974	265	+ 29	254	96	73	- 5	63	86
1975	310	+ 45	287	93	82	+ 9	75	91
1976	368	+ 58	297	81	111	+ 29	96	86
1977	410	+ 42	364	89	130	+ 19	120	92
1978	412	+ 2	380	92	134	+ 4	123	92
1979	424	+ 12	388	92	140	+ 6	131	94

* Active rigs include rigs en route.

Rig availability in U.S. waters started a rapid increase in 1976 in response to increasing demand. Total units doubled between 1972 and 1979, while the utilization rate increased from 73 to 94 percent. The U.S. fleet grew from 26 percent of the world fleet in 1975 to 33 percent in 1978.

Table 6 shows the distribution of rigs between the Gulf, Atlantic, and Pacific, and of wells drilled in U.S. waters in 1977 and 1978 with projections through 1981. It is assumed that rig demand will be proportional to upper level projected wells drilled, and that the ratio of wells drilled by mobile rigs to fixed platform rig wells drilled will not change.

Table 6 indicates that the demand for available rigs in U.S. waters could increase by 16 in 1981 over the June 1979 rig count. Units now under construction are shown in Table 7.

The number of rigs under construction in June 1979 in U.S. yards is more than enough to supply the U.S. upper level projected demand through 1981. The predominance of jack-ups in new construction reflects current preference. The June 1979 rig count showed that 58 percent of available rigs in U.S. waters were jack-ups.

TABLE 6

WELLS AND MOBILE RIGS OFFSHORE UNITED STATES

	Historical		Projected §		
	1977*	1978*	1979†	1980	1981
Gulf					
Wells	1,083	1,152	1,248	1,327	1,334
Rigs —Available	114	111	123	131	132
Active	110	107	117	124	125
Pacific					
Wells—Alaska	26	12	16	17	17
California	58	95	104	111	100
Rigs —Available	15	12	9	15	15
Active	10	7	7	11	10
Atlantic					
Wells	—	6	16	17	17
Rigs —Available	1	11	8	9	9
Active	—	9	7	8	8
Total U.S. Waters					
Rigs —Available	130	134	140	155	156
Active	120	123	131	143	143

* Rig count, *Offshore*, December 1977 and December 1978.
† Rig count, *Offshore*, June 1979.
§ Wells drilled are Outlook upper level possible.

TABLE 7

MOBILE OFFSHORE RIGS UNDER CONSTRUCTION *

	Jack-Up	Semi-submersible	Submersible	Drill Ships	Total
U.S. Yards	21	0	2	0	23
Foreign Yards	25	7	0	1	33
Total	**46**	**7**	**2**	**1**	**56**

* *Offshore*, June 1979

Offshore drilling activity and the demand for mobile rigs is expected to grow worldwide through the 1980's as it is generally believed that a large part of undiscovered petroleum resources is located under the seabeds. Rate of growth in U.S. waters is dependent upon the availability of offshore tracts for exploration, economic attractiveness, and the impact of regulations. In a favorable business environment and with additional opportunities for offshore leasing, the demand for new rigs could accelerate during this decade. Significant discoveries in the Atlantic or Pacific waters could also increase demand above that projected. If demand should exceed the short-term supply, requirements could be met by repartition of overseas units.

Table 5 indicates that, in the longer term, the offshore rig building industry has the capability of adding 40 to 50 rigs to the worldwide fleet annually. This capacity appears adequate to meet any probable long-term growth of the fleet which expanded at an average rate of 33 per year from 1972 through 1978. There may be periods of tightness and long lead times in units of choice, such as jack-up rigs, but any periods of rig short supply are not expected to have a significant effect on exploration and production activity due to the flexibility of the mobile fleet and the adaptability of the oil and gas industry to changing supply/demand conditions.

Drill Pipe

Drill pipe is heavy walled, high strength tubing; when coupled with heavy, coarse threaded connectors called tool joints, it serves to transmit rotating force and circulating fluid from machinery at the surface to the drill bit at the bottom of the hole. It is further described in Appendix C.

Drill pipe demand is a function of the active rig count which is determined by footage drilled but varies substantially from year to year due to swings in user inventories.

The U.S. drill pipe projected supply and demand balance is shown in Table 8. Projected domestic demand was calculated by applying the long-term average historic use of 300 tons of drill pipe per million feet drilled to the Outlook upper level possible projected footage. This factor is equivalent to about 31.5 tons per active rig year. Wide swings in domestic shipments are caused by substantial changes in drill pipe inventories held by users or warehoused outside of the pipe mills. Exports and total demands on U.S. mills were calculated under the assumption that the recent pattern of 40 percent exports will continue through 1981. The historical and projected capacity of U.S. mills is found in Chapter Four, Figure 21.

TABLE 8

U.S. DRILL PIPE SUPPLY AND DEMAND

	Feet Drilled (millions)	Active Rigs (Hughes)	U.S. Drill Pipe Shipments (thousand tons)			Domestic Tons		
			Domestic†	Export	Total§	Per Million Feet Drilled	Per Active Rig	U.S. Mill Capacity §
Historical								
1973	139	1,194	41¶	281	69f	295	34.3	—
1974	153	1,472	48	32	80	314	32.6	—
1975	179	1,660	58	38	96	324	34.9	—
1976	185	1,658	71	47	118	384	42.8	—
1977	215	2,001	58	38	96	270	29.0	—
1978	231	2,259	83	57§	140	359	36.7	142

	Feet Drilled (millions)	Active Rigs**	U.S. Drill Pipe Demand (thousand tons)			Domestic Tons		
			Domestic††	Export§§	Total¶¶	Per Million Feet Drilled	Per Active Rig	U.S. Mill Capacity§
Projected								
1979	261	2,486	78	52	130	300	31.4	146
1980	279	2,657	84	56	140	300	31.6	147
1981	293	2,790	88	59	147	300	31.5	151
1985	353	3,362	106§	40§	146	300	31.5	155
1990	436***	4,143	131§	40§	171	300	31.6	157

* Historical footage reported by API. Projected footage is Outlook upper level possible.
† 60 percent of total in 1974 through 1977.
§ *Tubular Steel*, Chapter 5.
¶ 1974 NPC report, p 63, Table 24.
** Calculated at 105,000 feet per rig year.
†† 300 tons per million feet drilled; 60 percent total shipments (1979-1981).
§§ Calculated 40 percent of total shipments (1979-1981).
¶¶ Calculated domestic plus foreign shipments.
*** Includes 20 million feet enhanced oil recovery drilling.

Table 8 indicates adequate drill pipe mill capacity for upper level activity through 1981, with the historical pattern of 40 percent exports continuing. Projected domestic demand could be met in 1985 if exports are reduced to 40 thousand tons (26 percent of capacity), as assumed in Chapter Four. The potential shortfall indicated for 1990, if 40 thousand tons are exported, could be relieved by further reducing exports to 26 thousand tons (17 percent of capacity). If projected demand is based on the Outlook lower level activity of 366 million feet drilled in 1990 and on 40 thousand tons exported, domestic demand could be met with 95 percent utilization of mill capacity. In any case, U.S. mill capacity dedicated to drill pipe could be increased at the expense of casing and tubing production, and exports could be adjusted to accommodate U.S. demand within the limits of total mill capacity.

Additional discussion of the drill pipe supply is presented in Chapter Four.

Tool Joints

Tool joints are coarse threaded two-piece couplings of high strength abrasion-resistant steel which are welded onto the ends of each length of drill pipe for connection into a string. The fact that tool joints are subjected to extreme stresses and varied requirements has resulted in the standardization of several designs by the American Petroleum Institute, plus proprietary threads offered by the same manufacturers. The place of tool joints in the drilling system is further described in Appendix C.

Tool joint demand is directly proportional to drill pipe demand and averages four tool joints per ton of drill pipe. Since most drill pipe for export is jointed domestically, export tonnage is included in the U.S. tool joint supply/demand anaylsis.

Table 9 shows the total present and projected capacity of seven tool manufacturers who responded to a survey compared with estimated total U.S. demand. Aggregated response is tabulated in Appendix G.

Response from manufacturers indicated that the 1978 capacity of 681,000 tool joints dedicated to the United States exceeded the estimated demand of 560,000 by more than 20 percent. Manufacturers reported plans for expanding worldwide capacity 72 percent by 1981. The portion dedicated to the United States would expand 44 percent to 982,000 tool joints, which far exceeds estimated requirements for Outlook upper level possible demands.

Responding companies also reported the capability of furthering expansion by 25 percent in 14 months and doubling capacity in 27 months. This compares with the Outlook upper level possible growth rate from 1981 to 1990 to average four and one-half percent per year.

Drill Collars

Drill collars are heavy, thick walled tubes of high strength steel used immediately above the drill bit at the bottom of the drill pipe. Drill collars serve several purposes, all related to drilling performance as further described in Appendix C.

Based on 1978 deliveries, the estimated U.S. demand for drill collars is 12 per active rig year. The demand shown in Table 10 was calculated from the Outlook upper level possible active rig count through 1981. The drill collar supply is that reported by responding manufacturers of the eight surveyed. Aggregated survey response is shown in Appendix G.

Drill collar manufacturers project a capacity increase in 1981 of 86 percent over 1978 with capacity dedicated to the U.S. market increasing by 71 percent. This would exceed projected high level possible demands in the United States by more than 60 percent. Manufacturers also reported the capability to expand projected 1981 capacity by 25 percent in about nine months and to double capacity in two years, while high level demand is projected to increase 4.5 percent per year.

Responding manufacturers indicated as possible but not quantified constraints a concern for mill rolling capacity after 1982 and for spot shortages of alloy steel by 1981.

Drill Bits

The drill bit is the cutting or boring element below the drill collar on the bottom of the drill string. Formation is penetrated through the combined cutting and grinding action of rotation and weight on the bit, and hydraulic action of circulating fluid pumped down the drill pipe. Drill bits are made in many sizes and types designed for various conditions. They are further described in Appendix C.

The demand for drill bits is determined by the type of formation, which may be sandstone, limestone, or shale with countless variations; total requirements can be estimated from footage to be drilled. Bit usage rises with hardness of downhole formations and greater depth where rocks surfaces may be tougher, and higher pressure and temperatures may cause increased wear.

TABLE 9

U.S. TOOL JOINT SUPPLY AND DEMAND

	Total U.S.* Drill Pipe Mill Demand (1,000 tons)	U.S. Tool † Joint Demand (thousands of units)	Total Capacity (thousands of units)	Percent Utilization	Total Deliveries (thousands of units)	Percentage of Capacity to U.S.	Total Capacity Dedicated to U.S. (thousands of units)	U.S. Demand as Percentage of Capacity Dedicated to U.S.
Historical								
1978	140	560	802	89	716	85	681	82
Projected								
1979	130	520	1,000	91	906	91	906	57
1980	140	560	1,161	97	1,121	77	895	63
1981	147	588	1,381	92	1,276	71	982	60

* Table 6, Drill Pipe. Total shipments, domestic and foreign.
† 4 tool joints per ton of drill pipe.

TABLE 10

U.S. DRILL COLLAR SUPPLY AND DEMAND

	Total U.S. Active Rigs Demand (Hughes)	U.S. Drill Collar Demand * (thousands of units)	Total Capacity (thousands of units)	Percent Utilization	Total Deliveries (thousands of units)	Percentage of Capacity to U.S.	Total Capacity Dedicated to U.S. (thousands of units)	U.S. Demand as Percentage of Capacity Dedicated to U.S.
Historical								
1978	2,259	27.1	42.6	88	37.7	75	32.1	84
Projected								
1979	2,486	29.8	63.8	90	57.5	76	48.2	62
1980	2,657	31.9	74.9	92	69.0	72	53.6	60
1981	2,790	33.5	79.2	94	74.3	69	55.0	61

* 12 per active rig year.

Based on industry information, the average life of a drill bit in 1978 was estimated to be 950 feet. Due to the trend toward the newer bit design which uses tungsten carbide button inserts in the bit cutting cones rather than hard faced steel teeth, performance is expected to improve to 1,000 feet per bit in 1981.

Table 11 shows the estimated demand for bits based on the Outlook upper level possible drilling activity. The supply was estimated independently and capacity expansion was based on announced plans.

The projected growth in the U.S. bit manufacturing capacity indicates an ample supply for domestic drilling through 1981 without reducing the current level of 40 percent exports.

TABLE 11

U.S. DRILL BIT DEMAND AND SUPPLY

	Outlook Upper Level Possible (million feet)	Feet Drilled Per Bit	Bit Demand (thousands of units)	Bit Capacity (thousands of units)		U.S. Demand as Percentage of Capacity Dedicated to U.S.
				Total	U.S. *	
Historical						
1978	231	950	243	433	260	93
Projected						
1979	261	965	270	490	295	92
1980	279	980	285	500	300	95
1981	293	1,000	293	510	306	96

* U.S. supply 60 percent of total manufactured in the United States.

Pressure Control Equipment

Pressure control equipment makes up the system designed to seal a drilling well at the surface of the hole below the derrick floor to prevent unwanted flow from the well through the annulus around the drill pipe or while the drill pipe is out of the hole. The assembly at the top of the well, called the blowout preventer (BOP) stack, may consist of any of several combinations of annular and ram-type blowout preventers controlled by a hydraulic operating system located at a safe distance from the well bore.

The typical blowout preventer stack contains one annular blowout preventer and two ram-type preventers operated by one control system. During the drilling of a well, three sizes of BOP's may be used to accommodate various pressure ratings and casing sizes. A BOP stack of appropriate size will be on the well during all drilling operations. Other sizes may be rented as needed by land rigs. Offshore rigs usually keep two or three sizes available on the rig, each containing one annular and three ram-type blowout preventers. The supply and demand for the very special design ocean floor mounted blowout preventers was not investigated in this survey.

Reverse flow through the drill pipe may be controlled with a kelly valve or drop-in valve. Collet and clamp connectors are usually used only on offshore submarine blowout preventer installations with floating rigs. These systems are further described in Appendix C.

Two indicators are significant in estimating the demand for pressure control equipment: active rigs and new rigs to be added to the total rig fleet. The capacity of the industry to deliver pressure control equipment and the capacity dedicated to U.S. demand were determined by survey. Aggregated response is shown in Appendix G. A comparison of indicated demand and projected supply is shown in Table 12.

The projected supply of blowout preventers dedicated to U.S. demand shows a growth of more than 60 percent in both annular and ram-type units between 1978 and 1981, and a 35 percent

TABLE 12

WORLDWIDE CAPACITY OF U.S. MANUFACTURERS OF PRESSURE CONTROL EQUIPMENT AND U.S. DEMAND INDICES

	1978			1979			1980			1981		
	Total			Total			Total			Total		
	Units	Percent Utilization	For United States	Units	Percent Utilization	For United States	Units	Percent Utilization	For United States	Units	Percent Utilization	For United States
Preventers												
Annular	1,040	78	680	1,325	94	837	1,440	94	940	1,690	94	1,090
Ram	2,350	98	1,460	2,960	95	1,895	3,710	96	2,300	3,450	96	2,430
Tubular Valves												
Kelly	3,550	79	2,600	4,300	76	3,060	5,000	80	3,500	5,550	82	4,035
Drop-In	300	100	150	950	37	570	1,100	46	660	1,400	100	910
Connectors												
Collet	30	30	3	30	30	4	30	–	4	30	25	3
Clamp	1,208	70	730	1,210	70	730	1,215	25	755	1,210	77	750
Control Systems	806	58	550	1,310	80	825	1,420	75	810	1,420	–	810
Active Rigs *	–	–	2,259	–	–	2,486	–	–	2,657	–	–	2,790
New Rig Additions *	–	–	426	–	–	458	–	–	355	–	–	314
Capacity Above New Rig Minimum Requirements												
Annular BOP †	–	–	254	–	–	379	–	–	585	–	–	776
Ram BOP §	–	–	508	–	–	978	–	–	1,590	–	–	1,804
Control Systems †	–	–	124	–	–	367	–	–	455	–	–	497

* From Table 3.
† One unit deducted from U.S. supply for each new rig addition.
§ Two units deducted from U.S. supply for each new rig addition.

growth in control system capacity dedicated to the United States. After deducting one annular BOP, two ram-type BOP's, and one control system for each projected new rig, the capacity to build these items was reported by respondents to grow at a much higher rate than the projected active rig count. Some of the projected capacity would be utilized by those new rigs which require more than one typical BOP stack. All offshore rigs use at least three ram-type BOP's in each stack. In addition, the larger well servicing units require one or two ram-type BOP's. These are long-life items but there will be some attrition due to wear and obsolescence.

Manufacturers of blowout preventers reported high utilization of capacity in 1978 and anticipate high utilization through 1981. Capacity projected for 1981 could be increased by 25 percent in eight months to a year and could be doubled in two years. Control system capacity could expand 25 percent in three months and double in one year.

Kelly valve manufacturers show a capacity growth projection in 1979 of 21 percent over 1978 and of 56 percent by 1981, continuing about 80 percent utilization of capacity. The capacity dedicated to U.S. demand is enough to supply one kelly valve for each new rig addition plus a replacement for each active rig.

Projected drop-in valve capacity tripled from 1978 to 1979 and is projected to continue increasing so that the part projected for the United States in 1981 would be six times the 1978 capacity. Further increases in the accelerating demand projected by the manufacturers for drop-in valves can be met by increasing manufacturing capacity after 1981 by 25 percent in six months and doubling it in one year.

Collet and clamp connectors are specialty items used almost exclusively in offshore floating drilling operations. Manufacturers project no increase in capacity utilization above the 1978 demand of 30 percent for collet connectors and a slight increase from 70 to 77 percent for clamp connectors. No increases in capacity for these items are projected through 1981. If the demand should increase, collet capacity could be increased 25 percent in one year and doubled in two years. Clamp connector capacity could increase 25 percent in seven months and double in one year.

In summary, manufacturers of drilling pressure control equipment have plans to increase capacity significantly through 1981. The projected supply will be adequate through that period for the Outlook upper level drilling activity. Accelerating demand after 1981 can be supplied by increasing capacity 25 percent in three to six months and doubling capacity in 12 to 18 months.

Drilling Fluids

Drilling fluids are complex blends of minerals chemically suspended in a water- or oil-base medium. Requirements for these fluids vary extremely in density and composition with well depth and geological conditions. They are all designed to prevent formation fluid or gas from entering the bore hole, enhance formation penetration of the bit by circulation, and transport formation cuttings to the surface. The functions and compositions of drilling fluids are described in more detail in Appendix C.

The demand for materials to be added to the natural liquid/solids suspension generated while drilling is a function of feet drilled and is modified by well depth, formation composition, hardness, and temperature. Since the average depth of wells to be drilled in the United States is projected to increase, the demand for drilling fluid additives is expected to increase at a higher rate than footage drilled.

The drilling fluids supply industry was surveyed for 1978 experience and projected demand and supply for products by year through 1981 and 1990. Aggregated response is shown in Appendix G. Consolidated data for the three most critical products are shown in Table 13, compared with the upper level projected drilling activity. These products—barite, bentonite, and lignosulfonate—make up 95 percent of the tonnage and 50 percent of industry sales value.

Suppliers project that the recent high growth rate in demand will continue and that the industry can expand the supply out to 1990. If these high demands should continue, barite imports, which were two percent of the supply in 1978, would grow to seven percent in 1981 and 12 percent in 1990. The domestic lignosulfonate demand is projected to exceed the domestic supply by 1980, requiring two to three percent imports in 1981 to 1990.

TABLE 13

DRILLING FLUID ADDITIVES
U.S. DEMAND AND SUPPLY
(Thousand Tons)

	Historical	Projected			
	1978	**1979**	**1980**	**1981**	**1990**
Barite					
Demand	2,258	2,541	2,838	3,172	5,572
Supply—Domestic	2,209	2,401	2,664	2,950	4,922
Supply—Imported	49	140	175	223	650
Total Supply	**2,258**	**2,541**	**2,839**	**3,173**	**5,572**
Bentonite					
Demand	570	585	663	743	1,328
Supply—Domestic	570	585	663	743	1,328
Supply—Imported	0	0	0	0	0
Total Supply	**570**	**585**	**663**	**743**	**1,328**
Lignosulfonates					
Demand	59	65	71	77	130
Supply—Domestic	59	65	70	77	128
Supply—Imported	0	0	0	2	3
Total Supply	**59**	**65**	**70**	**79**	**131**

Outlook Upper Level Possible Drilling Activity
(From Table 1)

	Historical	Projected			
	1978	**1979**	**1980**	**1981**	**1990**
Feet Drilled (millions)	231	261	279	293	435
Average Well Depth (feet)	4,771	5,011	5,038	5,068	5,769

The high growth projections of suppliers are compared with the high level drilling activity growth rate in Table 14. Suppliers project demand for additives to continue to be near 12 percent per year through 1981 and average more than six percent compounded out to 1990. This is a higher growth rate than the upper level projection of a declining growth to about seven percent in 1980, five percent in 1981, and 4.5 percent out to 1990.

Projected growth in barite demand as a function of feet drilled is compared with projected upper level well depth in Table 15. The comparison indicates that the drilling fluid additive industry's supply projection is more than adequate to meet the demands of the Outlook upper level drilling activity. However, several concerns were expressed for potential constraints which could impact capability:

- The increase of 66 percent in feet drilled from 1973 through 1978 has placed a significant strain on barite ore production. Most of the proven reserves of high grade ore have been depleted. Exploration and development of new reserves is time consuming and development of the lower grade ores requires large investments for more expensive processing plants. The tight supply is expected to continue, resulting in a growing reliance on imports.

- The supply of lignosulfonate is expected to be more restricted over the next several years. The raw material is a byproduct of the paper industry, which is under severe pressure of environmental regulations to reduce pollution. Technological advances have eliminated this byproduct from new plants under construction. These developments have led to significant cost increases and a limited supply of the basic raw materials, resulting in the projection of imports commencing in 1981.
- The current rail car shortage affects delivery of all drilling fluid additives and has had a pronounced effect on bentonite delivery. Almost all of the drilling fluid grade bentonite produced in the United States is mined and processed into finished material in Wyoming. The rail car shortage has contributed to substantial lead time for delivery to stock points where there is drilling activity. Since the time required to obtain new cars exceeds two years, there may be spot shortages of bentonite over the next several years.

TABLE 14

DRILLING FLUID ADDITIVES PERCENTAGE GROWTH IN U.S. DEMAND AND SUPPLY (Projected Compound Annual Growth Rate—Percentage)

	1979	1980	1981	1990
Barite	12.5	11.7	11.8	6.4
Bentonite	2.6	13.3	12.1	6.5
Lignosulfonates	10.2	7.7	12.9	6.0
Feet Drilled	13.0	6.9	5.0	4.5

TABLE 15

BARITE PROJECTED DEMAND AND SUPPLY VERSUS FOOTAGE DRILLED AND WELL DEPTH

	Historical	Projected			
	1978	1979	1980	1981	1990
Barite/Million Feet Drilled (thousand tons)	9.8	9.7	10.2	10.8	12.8
Percentage Change From 1978	–	−1	+4	+10	+31
Average Well Depth Percentage Change From 1978	–	+5	+6	+6	+21

Chapter Four
Tubular Steel

Introduction

Adequate supplies of oil country tubular goods (OCTG—oil well casing, tubing, and drill pipe) are expected to be available through 1981, recognizing:

- The demonstrated ability of the domestic steel industry to ship at the rate of 3.0 million tons during early 1978
- The expansion plans of domestic oil country tubular producers

and considering:

- Estimates of current OCTG inventories in the hands of distributors and consumers
- Import and export levels of these products during this period.

However, the relationship between domestic tubular manufacturing capacity and projected demand by 1981 is close enough that significant user inventory building, a significant drop in import levels, and/or a dramatic increase in exports could result in a tenuous supply/demand balance.

Beyond 1981, demand would exceed supply by 100,000 tons in 1985 and by a disturbing one million tons by 1990, assuming the import/export balance remains relatively stable. This shortfall might be remedied by one or more alternatives, including: increased imports; decreased exports (only partially effective); construction of new tubular mills with a shifting of raw steel from other products; or expansion of raw steel supplies as well as additional tubular mill and finishing capacity, all requiring heavy capital investments.

The most secure and reliable supply would result from the expansion of domestic tubular production capacity accompanied by the raw and semi-finished steel capacity to support it. In order for such expansions to occur, the steel industry will need clear, predictable incentives to proceed. The largest single barrier to expansion is the lack of a federal energy policy which would result in a predictable growth of demand for oil country tubulars. Without a reasonably predictable market, the industry cannot justify the heavy capital investments required for significant capacity expansion.

In addition to market risks, the steel industry's ability to generate capital for modernization to improve its productivity and competitiveness and for expansion to meet potential growth in demand is restrained by price controls, federal tax policies, and mandated expenditures for pollution controls. Government efforts to curtail tubular steel imports have not been effective. Indications are that these policies have stimulated rather than reduced tubular import tonnage.

These conclusions resulted from the analyses of supply/demand balances of casing and tubing which historically have accounted for 96 percent (78 percent and 18 percent, respectively) of mill shipments, and of drill pipe, which accounts for the remaining four percent. The analyses considered effects of imports, exports, re-used tubulars, and likely consumption for oilfield line pipe. Similar analyses were conducted to assess the outlook for high strength and carbon steel casing and tubing and for proprietary connections used in critical service wells.

Analysis and Results

The most important source of oil country tubulars (casing, tubing, and drill pipe) is the domestic steel industry. Figures 9 and 10 portray shipments of casing and tubing by these producers from 1973 to 1978 and their existing and planned capacity for the years 1979 through 1981,

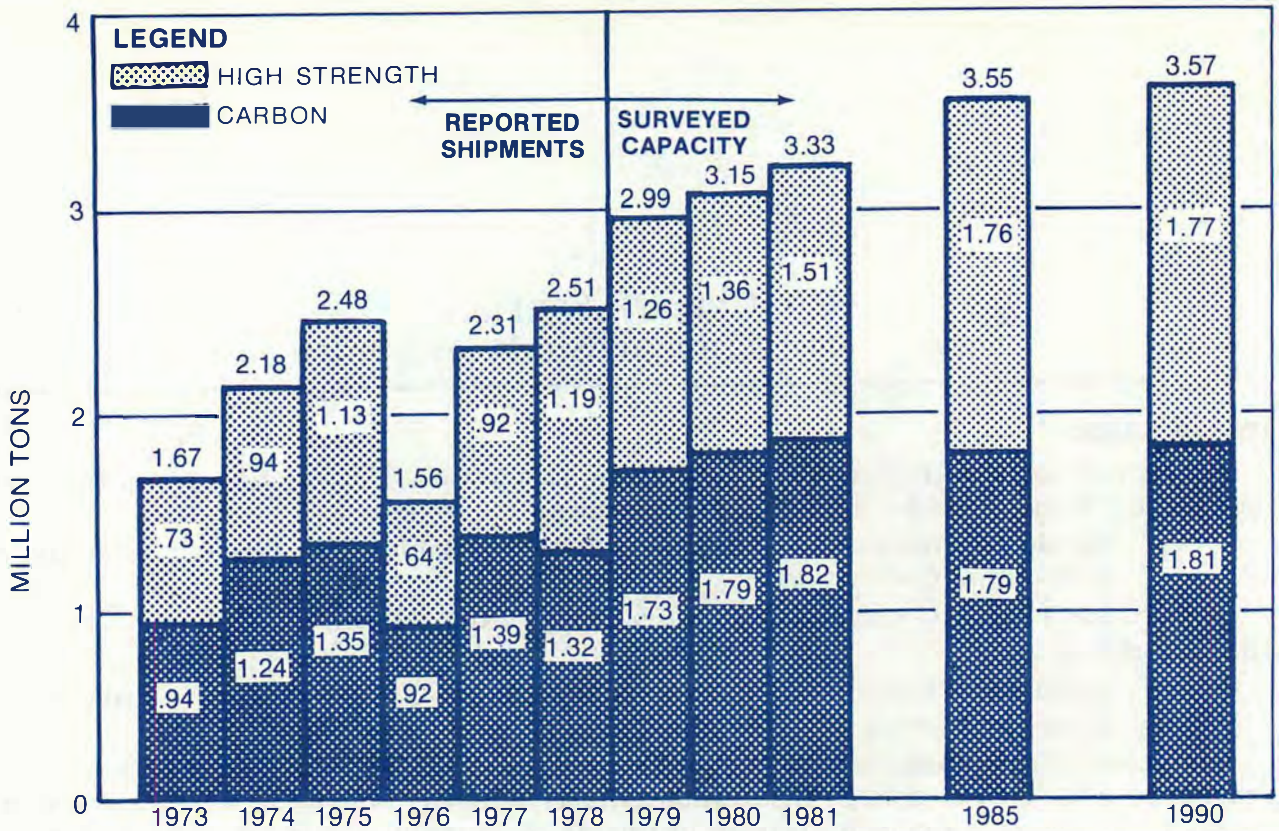

Figure 9. Casing and Tubing — Historical Shipments and Surveyed Capacity of U.S. Mills by Strength Levels.

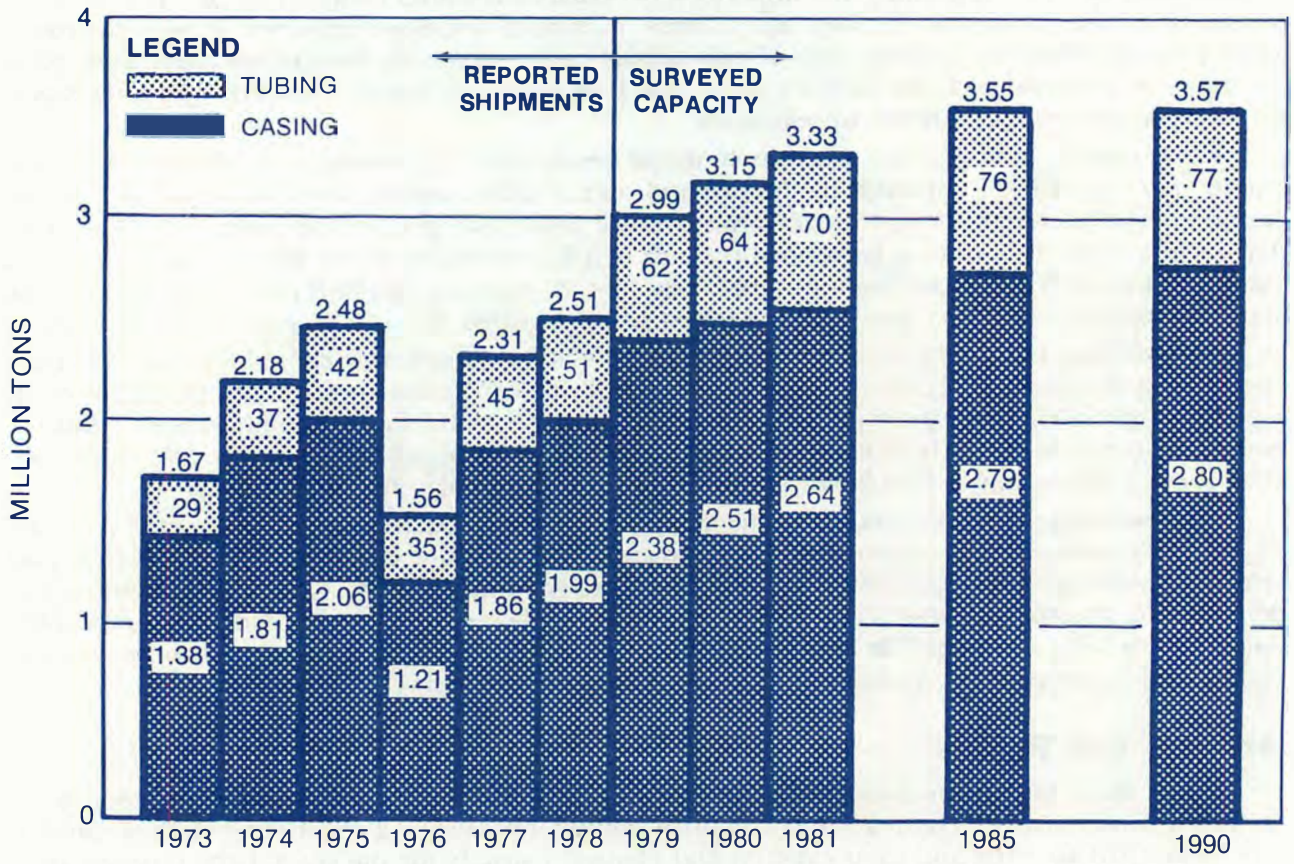

Figure 10. Casing and Tubing — Historical Shipments and Surveyed Capacity of U.S. Mills.

1985, and 1990. The figures also indicate the mix between carbon (55,000 pounds per square inch [psi] minimum yield strength and lower grades) and high strength (grades above 55,000 pounds per square inch [psi] minimum yield strength).

Shipments of OCTG rose sharply in 1973, 1974, and 1975 as the surge in drilling activity and inventory building drove demand upward. Shipments slumped in 1976 as oil and gas producers worked off part of the inventories they had accumulated in the prior years. Mill shipments rose in 1977 and 1978, with 1978 shipments exceeding the previous high achieved in 1975. While 1978 was a year of strong demand, this demand tapered off in the last half of the year. Monthly shipments in the first half indicated that the domestic steel industry could have shipped at least 3 million tons if the demand had remained strong all that year.

Capacity for future OCTG production was projected based on the survey responses of 15 domestic manufacturers. This projection is considered a reasonable estimate of domestic tubular goods supplies.

Other elements in the OCTG supply equation are imports, exports, miscellaneous supplies, and inventories. For a number of reasons, reliable statistics on imported OCTG are not available; however, reasonable estimates can be made. Estimated imports of oil country tubulars rose from about seven percent of apparent domestic consumption in 1974 to about 24 percent in 1978. This occurred because foreign capacity (primarily in Japan) was increased dramatically in this time frame, while foreign demand declined from its peak in 1975. In addition, world market OCTG prices in 1974-1975 were substantially higher than U.S. domestic market prices but have been below those of domestic mills since 1976 (Figure 11).

Figure 11. Comparison of Import and Domestic Prices — Carbon Oil Well Casing (Dollars per Net Ton Delivered in Houston).

The 1979-1981, 1985, and 1990 import levels shown in Figure 12 were estimated based on two recent studies of long-term trends of steel consumption in the United States.[1] An estimate of 15 percent of apparent consumption was selected as their estimate of future imports. Obviously, many factors could influence actual activities, causing these estimates to be in error.

Exports of OCTG represent a reduction of supply available for drilling in this country. As shown in Figure 13, they normally range from 100,000 to 150,000 tons per year. Notable exceptions were the peak worldwide demand years of 1974-1975 and estimates for 1979-1981. This projected increase represents actual and potential demand by the People's Republic of China which may or may not extend beyond their reported purchases in 1979.

Projections for the 1985-1990 period are somewhat higher than the 100,000-150,000 ton level to reflect expected increases in world drilling.

A supply of miscellaneous limited service casing and tubing has always been available to the oil and gas drilling industry. These unreported tubular products are a combination of reclaimed products from old and abandoned wells, downgraded mill rejects, and plain end electric resistance weld (ERW) tubular products threaded and coupled by miscellaneous end finishers for use in noncritical, low pressure, onshore wells. The estimated historical and projected supplies of these products are shown in Figure 14.

One of the most significant factors in the supply equation is the build-up and runoff of inventory. As shown in Figure 15, there have been two cycles of build-up during the 1973-1978 period. Not unlike other steel products or other essential commodities, the hint of tight supply or extended deliveries brings with it a cycle of inventory building followed by an inevitable runoff. Unfortunately, users do not have equal ability to project their exact needs. Dislocations are usually the result.[2]

In 1973, inventories were much lower than they are today. Estimated inventories at the end of 1978 were 1.8 million tons, or about 1.5 million higher than at the beginning of 1973. This broadly held increment of supply is equivalent to over six months of domestic production capability at projected 1979 capacity rates.

Current inventories, domestic production capacity, and other supplies will allow the industry to accommodate potentially significant drilling activity increases during 1979-1981 without the severe dislocations that were evident in the 1974-1975 period.

For a complete summary of the upper level supply/demand situation of tubular products, see Table 16.

Casing and Tubing

The demand for casing and tubing depends on a number of factors, but footage drilled in the search for oil and gas is generally recognized as the best indicator of OCTG consumption. Deeper wells use more tons per 1,000 feet than shallow wells because of the larger diameter casing sizes used and thicker pipe walls required for structural strength and containment of higher pressures encountered at greater depths. The relative proportions of productive and dry holes is also a factor. Productive wells use more tonnage as tubing and production casing are not required in dry holes. In addition, federal regulations and risk management result in the use of more tons per 1,000 feet of hole drilled in offshore areas than in most onshore locations.

An estimate of tubular consumption was made based on the Outlook projected range of possible drilling activity. Figure 16 shows historical and projected levels of drilling activity (footage drilled) and estimated demand of casing and tubing. Based upon the upper level of the range of possible drilling activity, casing and tubing usage would increase from 3.2 million tons in 1978 to 5.4 million tons in 1990, an increase of 69 percent. Using the lower level forecast, 1990 usage would be some 900,000 tons less, still an increase of 40 percent over 1978.

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[1] *Industrial Economics Review*, U.S. Department of Commerce, May 1974, Vol. I, pp. 11-24; *Steel in the U.S. in the 1980's: Short Supply*, Chase Econometric Assoc., June 1979, Vol. I.

[2] *Dislocation* is defined as an occurrence in which supply and demand may be in balance totally, but supply in certain geographic areas or in the hands of certain users may not equal the geographic or individual user demand.

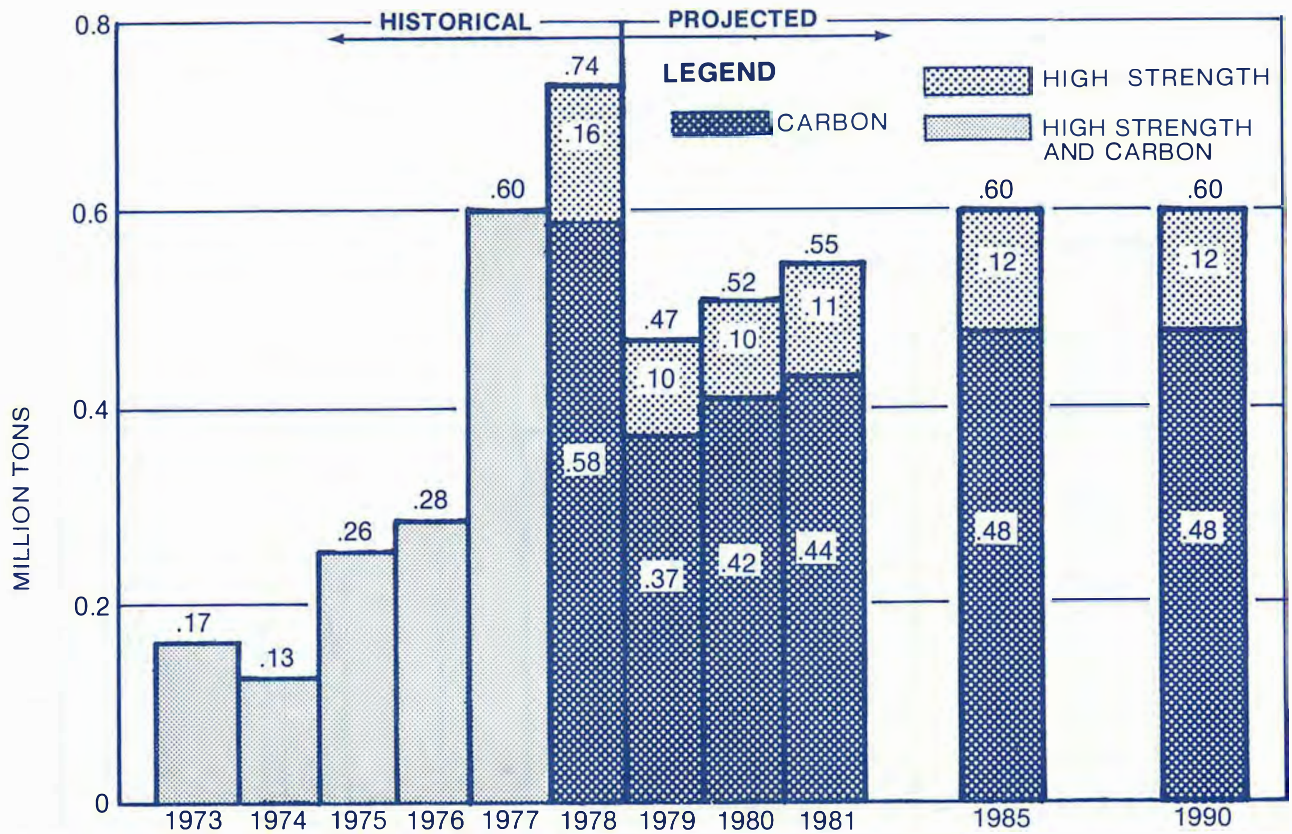


Figure 12. Imports of Casing and Tubing — Estimated.

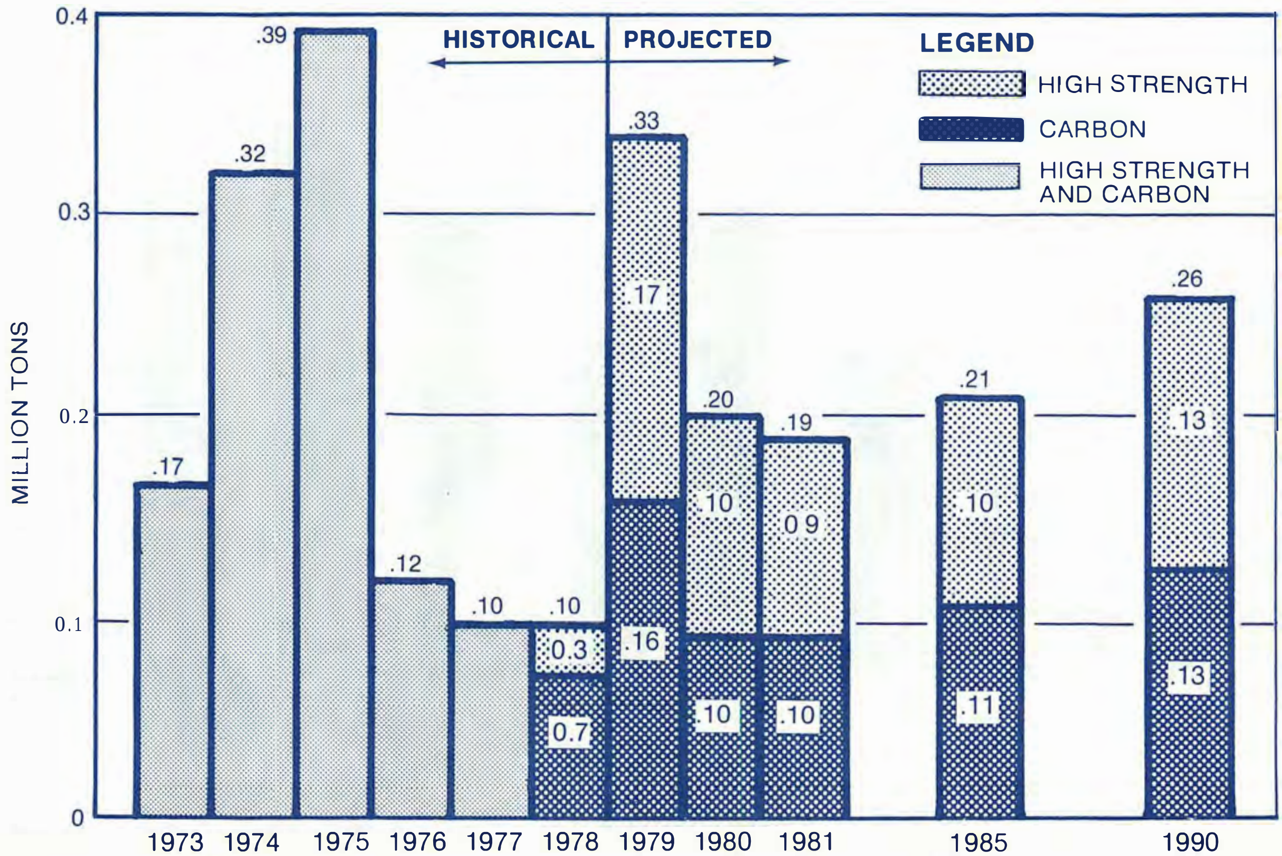


Figure 13. Exports of Casing and Tubing —Estimated.

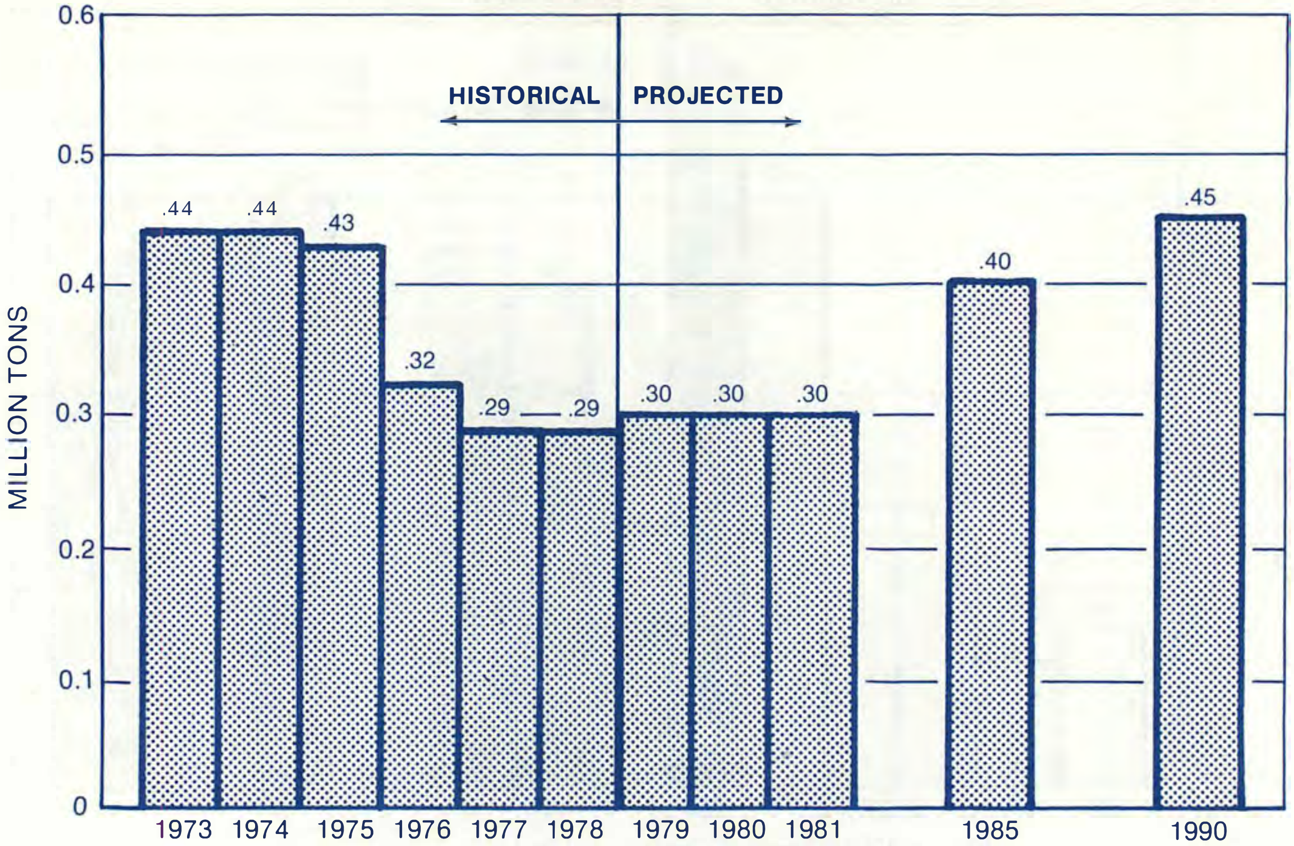


Figure 14. Miscellaneous Casing and Tubing Supply — Estimated.

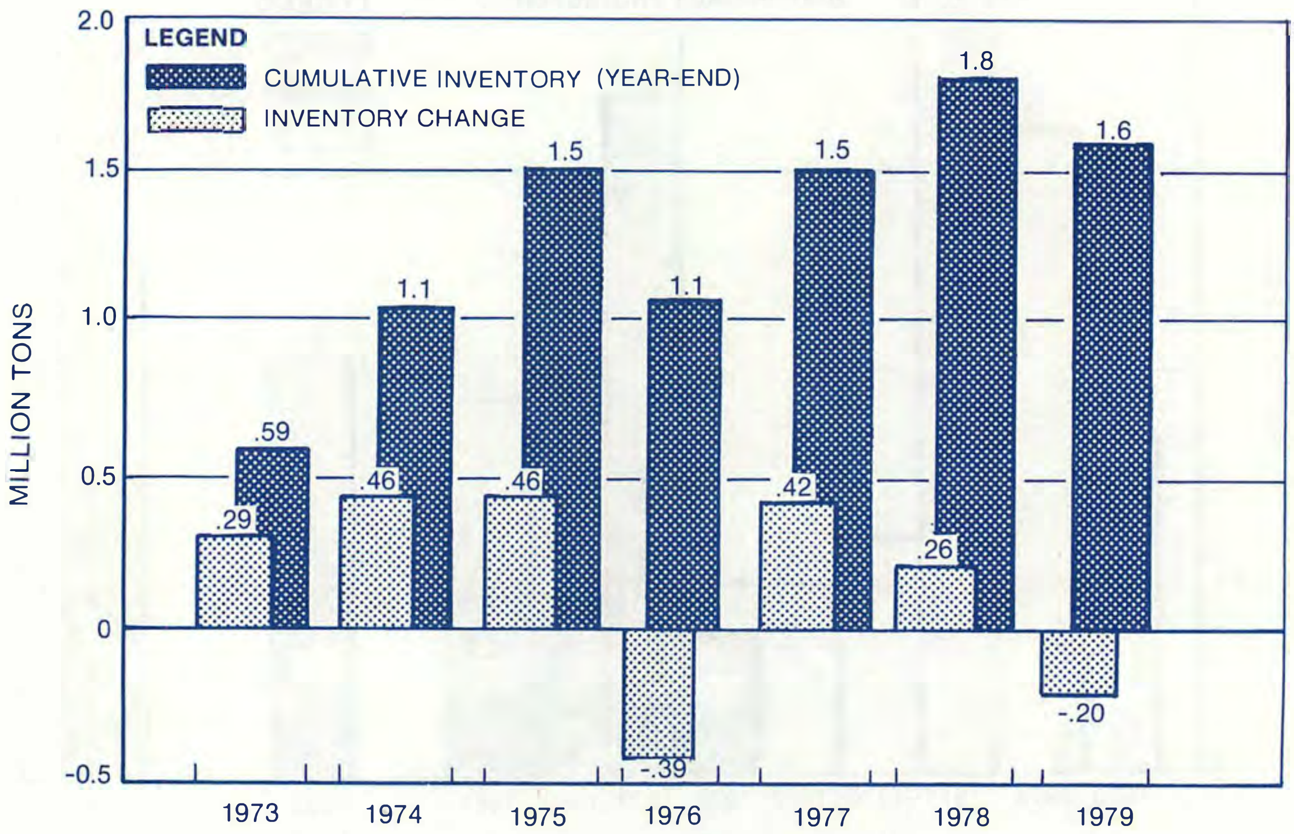


Figure 15. Casing and Tubing Inventory Change — Estimated.

TABLE 16

OCTG—UPPER LEVEL SUPPLY AND DEMAND—1973-1990
(Thousand Tons)

	Historical						Projected				
	1973	**1974**	**1975**	**1976**	**1977**	**1978**	**1979**	**1980**	**1981**	**1985**	**1990**
SUPPLY											
OCTG Shipped by U.S. Mills*	1,736	2,261	2,578	1,678	2,405	2,647					
Less Drill Pipe	64	80	96	118	96	140					
Casing & Tubing Shipments	1,672	2,181	2,482	1,560	2,309	2,507					
OCTG Capacity							3,140	3,300	3,485	3,705	3,730
Less Drill Pipe							145	145	150	155	155
Casing & Tubing Capacity							2,995	3,155	3,335	3,550	3,575
Exports—All OCTG †	198	348	430	169	140	155	375	250	250	250	300
Less Est. Drill Pipe §	28	32	38	47	38	57	50	55	60	40	40
Casing & Tubing Exports	170	316	392	122	102	98	325	195	190	210	260
Est. Imports Casing & Tubing	172	132	263	281	600	743	470	520	550	600	600
New Casing & Tubing Available for Domestic Use	1,674	1,997	2,353	1,719	2,807	3,152	3,140	3,480	3,695	3,940	3,915
Miscellaneous Sources	440	440	430	315	285	285	300	300	300	400	450
Total Supply—Casing & Tubing	**2,114**	**2,437**	**2,783**	**2,034**	**3,092**	**3,437**	**3,440**	**3,780**	**3,995**	**4,340**	**4,365**
DEMAND											
Est. Casing & Tubing Usage	1,824	1,976	2,320	2,424	2,676	3,177	3,065	3,585	3,695	4,450	5,400
INVENTORY-DISTRIBUTOR-USER ¶											
Est. Beginning of Year Inventory	300	590	1,051	1,514	1,124	1,540					
Year-to-Year Change	+290	+461	+463	−390	+416	+260					
Est. End of Year Inventory	590	1,051	1,514	1,124	1,540	1,800					
Footage Drilled (thousand feet)**	142,576	157,558	185,688	190,927	215,535	242,000	240,000††	279,000§§	293,000	353,000	435,000
Tons of Casing and Tubing Used Per Thousand Feet of Hole Drilled	12.8	12.5	12.5	12.7	12.4	13.1	12.8	12.8	12.6	12.6	12.4

* AISI (Net Shipments).
† Department of Commerce.
§ Drilling Equipment, Chapter Three.
¶ While no projections of inventory levels were made beyond 1979, *normal* inventories would be expected to approximate six months' usage.
** API (as adjusted).
†† Estimated—Assumes 1979 approx. equal to 1978.
§§ Upper limit forecast by the Outlook and Materials Subcommittee 1980-1981—1985—1990.

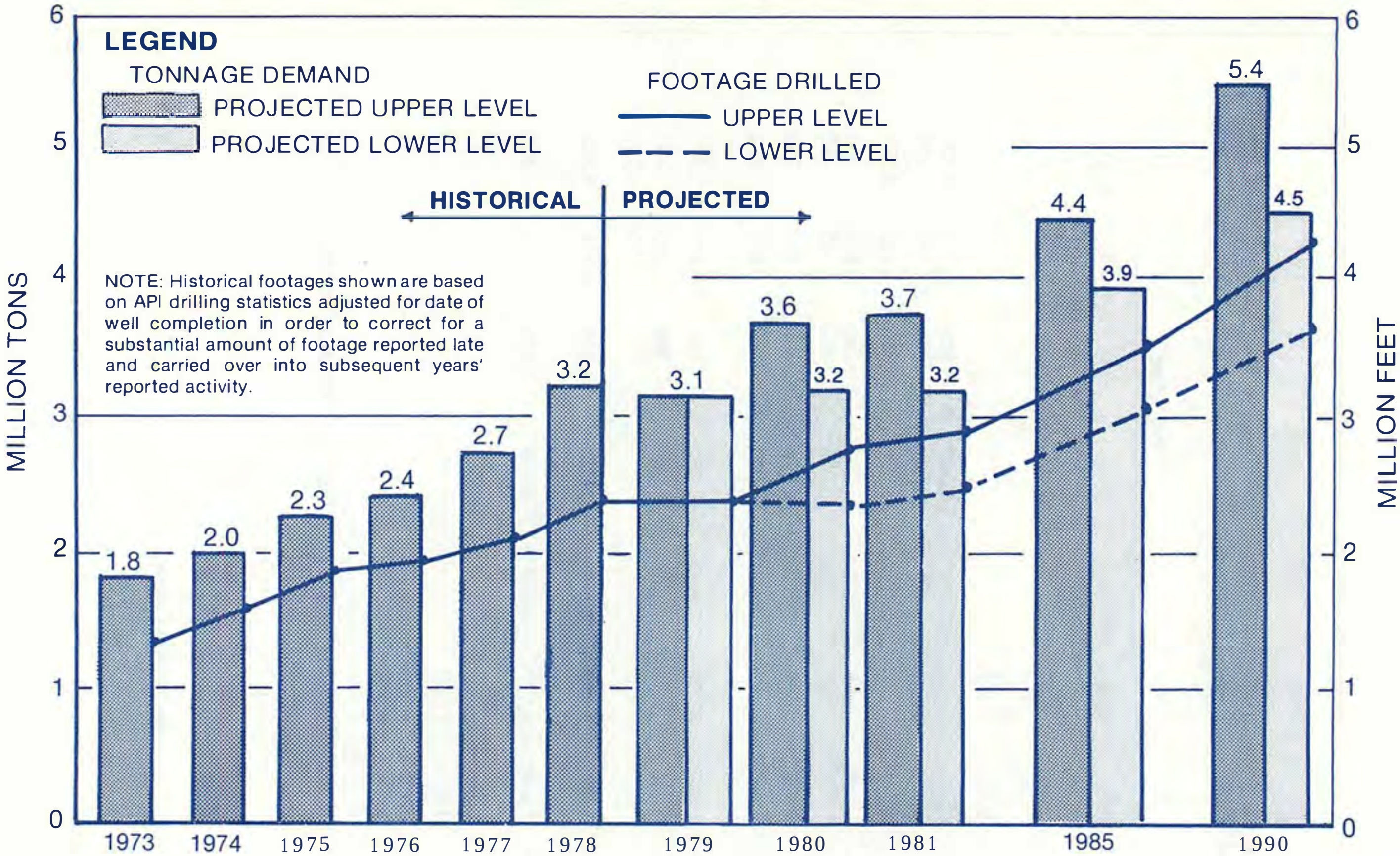


Figure 16. Casing and Tubing Demand vs. Footage Drilling Ranges.

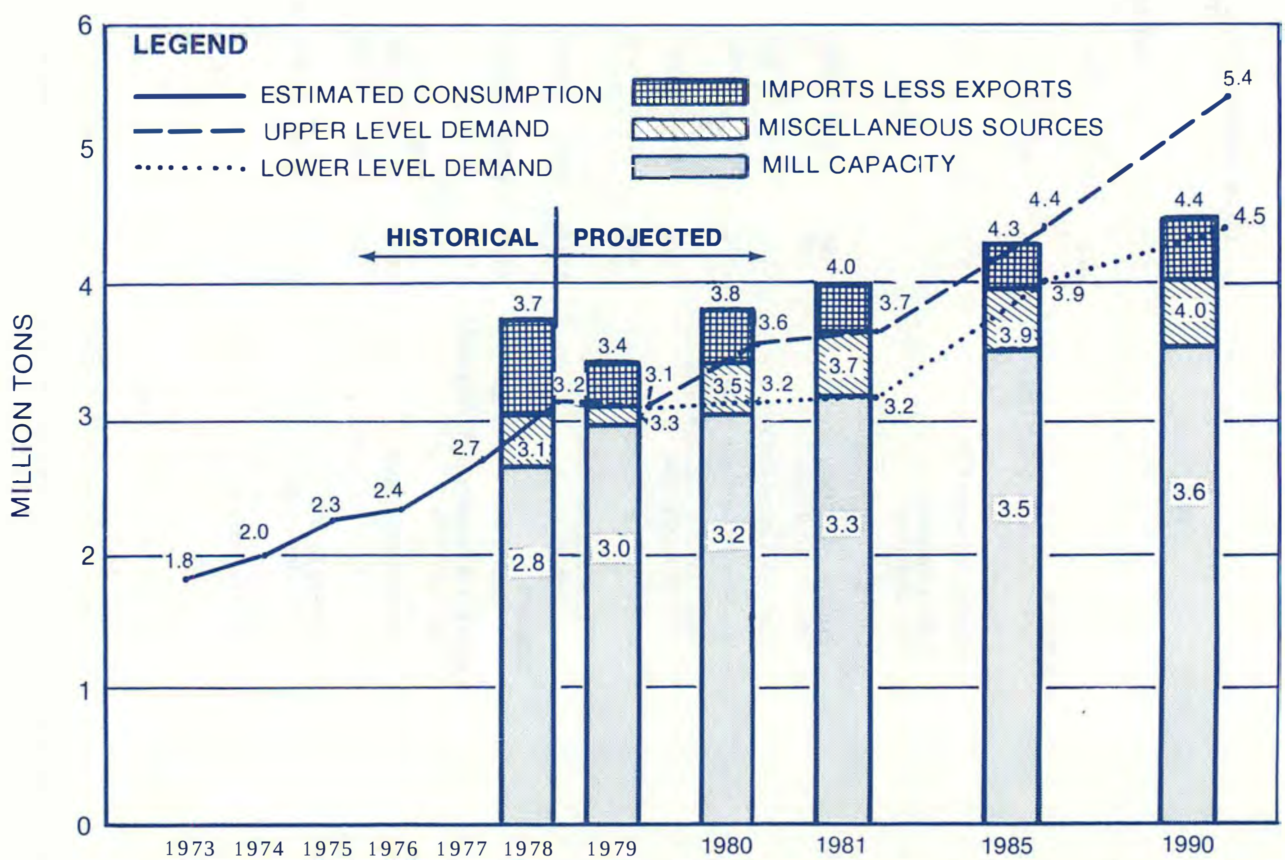


Figure 17. Demand (Estimated Consumption) vs. Apparent (Estimated) Supply — Casing and Tubing.

Figure 17 compares projected demand for casing and tubing to the three elements of casing and tubing supply: domestic mill capacity, estimated tonnage from miscellaneous sources, and the estimated balance of imports less exports. Projected supplies of casing and tubing will probably exceed the upper level of possible demand through 1981, provided that:

- Casing and tubing from miscellaneous sources remains relatively stable at about 300,000 tons per year (This is only a relative certainty. Tonnage from these nonreported sources would likely increase if demand accelerated.)
- The net balance of imports less exports remains relatively stable
- The increase of casing and tubing manufacturing capacity (indicated in the survey of domestic mills) from 2.99 million to 3.33 million tons in the 1979-1981 period occurs.

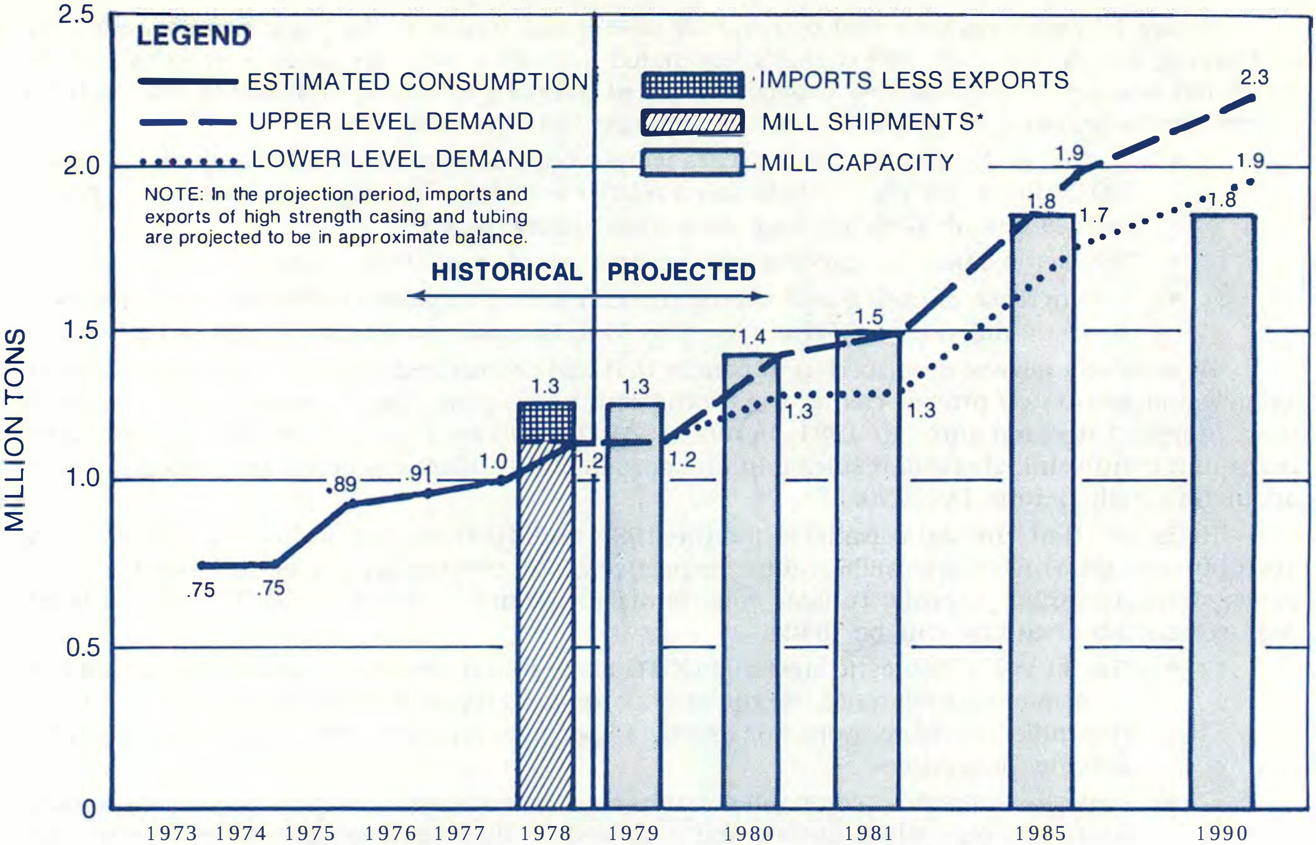
By similar analyses, described in Appendix H, it was determined that planned capacity expansions would adequately provide casing and tubing with high strength and carbon steel properties to meet projected demand through 1981. Beyond 1981 the outlook is uncertain, but all indications point to a continuing shortfall resulting in an approximate 100,000 ton deficit by 1985 growing to about one million tons by 1990.

[It is felt that the data available for the 1985 and 1990 periods indicating a shortfall of 100,000 tons growing to one million tons, respectively, still provide an inadequate basis for firm conclusions regarding potential tubular constraints to the upper limit forecast. However, it is felt that certain observations can be made:

- The survey of domestic steel mill OCTG current and projected capacity did not include for respondent reference the *upper limit demand* forecast (it did not exist at that time). The mills, therefore, were not asked to speculate on what they might do given these demand projections.
- Typically, individual companies within the domestic steel industry announce planned expansion only when funded and approved by their management. It is assumed that any significant planned expansion, as yet unapproved, was not reported in the survey.
- While the total supply of OCTG can be increased by mill expansion, availability can also be increased by upgrading existing mill facilities. Constant technological improvements to electric resistance weld casing and tubing will make the product more acceptable for critical use. The timing of this progress is not predictable, but it will occur, particularly when demand approaches the upper limits of supply. Also, during periods of high demand, there is a tendency towards standardization, thus utilizing each mill at its optimum production. The user finds he can get what he needs, but not necessarily what he wants.]

While total casing and tubing availability is of primary concern, the tonnage split within this total—of both demand for and supply of the high strength (above 55,000 psi) grades—is of deep concern. Although some substitution of high strength by heavier wall carbon grades is possible, the use of high strength is more economical and operationally acceptable for challenging drilling situations (deep holes, offshore, and hostile geological formations). Figure 18 portrays the high strength supply/demand balance indicating a shortfall of 150,000 tons by 1985 and 550,000 tons by 1990. Although the overall shortfall of both carbon and high strength is projected at 100,000 tons by 1985, this difference reflects a surplus of carbon grades projected for that time. However, if additional tubular capacity is added to meet total upper level demand, it can be assumed that the percentage split needed for high strength will become available. The basis for this assumption is that most seamless and some electric weld OCTG now produced in lower carbon grades could be upgraded to high strength by adding heat treating and finishing facilities in a 24- to 30-month time span.

Figure 19 compares the three elements of carbon casing and tubing supply including surveyed domestic mill capacity, miscellaneous tonnage, and imports to the extent they exceed exports. No shortfall is foreseen in the 1979-1981 period. Capacity is judged to be adequate through 1985, but by 1990 an additional 500,000 tons will be needed assuming that imports exceed exports by 350,000 tons. On the other hand, if worldwide requirements increase as expected, the availability of imported carbon grades could be less than projected. Since the bulk of consumption is of relatively few sizes, weights, and grades and because (lower cost) carbon grades are more economical to



*Mill shipments exceeded surveyed capacity.

Figure 18. Demand (Estimated Consumption) vs. Apparent (Estimated) Supply — High Strength Casing and Tubing.

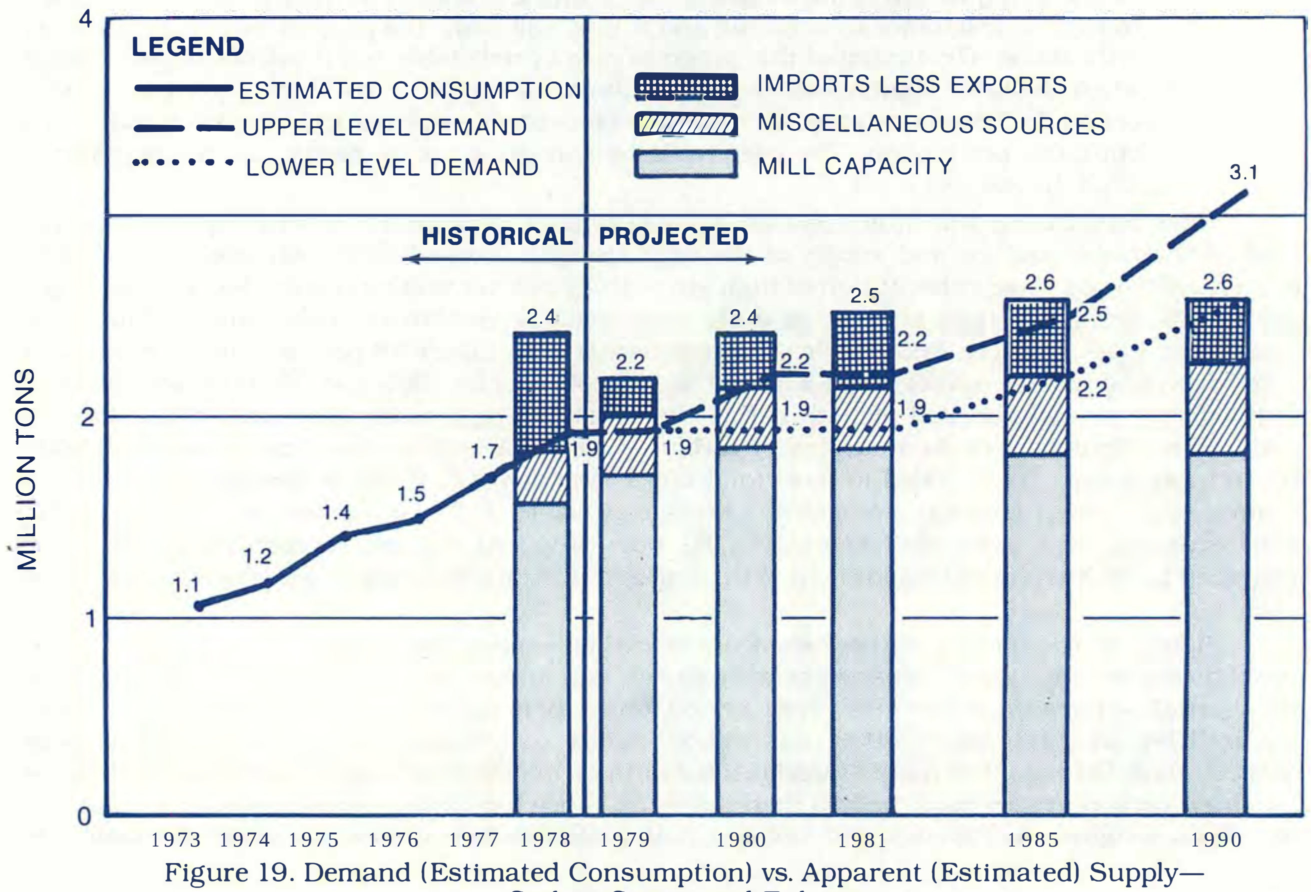


Figure 19. Demand (Estimated Consumption) vs. Apparent (Estimated) Supply— Carbon Casing and Tubing.

import and inventory, this heavy dependence on imports could lead to a more excessive shortfall for domestic drilling than historical patterns would seem to indicate.

Proprietary Connections

Within the larger market for casing and tubing there exists a market for specialized casing and tubing connections, commonly referred to as proprietary joints. The demand for these special connections is usually related to critical wells where depths, pressures, temperatures, or unusual drilling conditions indicate a need for leakproof or greater joint strength connections deemed unobtainable from normal mill production. Foreign demand for these products leads to considerable international movement of high strength tubulars and proprietary threads.

The supply projection is the domestic capacity determined by the survey of domestic manufacturers. Historic shipments (1973-1978) will not be covered here in order to protect the confidential nature of market share data. Furthermore, while the import/export balance has probably favored exports, it was assumed that imports and exports would balance in future years.

Figure 20 illustrates that the availability of proprietary joints appears to offer no constraints to the estimated demand for product through 1990. Assuming only modest exports, planned additions to U.S. capacity appear excessive considering forecast (upper level) demand.

Drill Pipe

Drill pipe is a heavy walled, high strength, predominately seamless tubular product, generally made on the same facilities which produce casing and tubing. A description of its function in drilling operations is presented in Appendix C.

Estimates of past and projected consumption are reported in Chapter Three. Drill pipe demand is related to footage drilled and to new rig construction. Drill pipe wears out during drilling, and at least one new string is furnished to each new rig (generally two if the rig is exported). Some additional demand also stems from miscellaneous oilfield and non-oilfield requirements. Projected demand is based on the relationship of past drill pipe shipments less exports and footage drilled. Historical demand reflects reported domestic mill shipments as imports are felt to be relatively minor. Exports were estimated for 1973-1977 because they were not reported by the Department of Commerce until 1978. Supply of this product (in semi-finished form) is predominately from domestic seamless mills. Because it is generally produced from high strength steel on facilities which can also manufacture seamless tubing and casing, it is likely that more latent capacity to produce drill pipe exists, but its production would be at the expense of seamless casing and tubing tonnage.

Like proprietary joints, finishing of drill pipe is done by outside processors who equip the pipe with threaded connections called tool joints. Tool joint supply and jointing capacity are discussed in Chapter Three. The supply/demand relationship shown in Figure 21 indicates no constraints on the upper level drilling projection in the 1979-1981 period. Beyond 1985, however, demand begins to exceed supply on the upper level projection even assuming some reduction in exports. As a percentage of total OCTG, the deficit is not large and could be made up by increasing drill pipe production at the expense of casing and tubing or by an additional reduction in exports or by a combination of both.

Line Pipe

For the purposes of this study, line pipe is defined as all pipe used to convey gas and oil from successful wells to storage tanks and pipe lines. While the 1974 study covered the supply/demand requirements for this type of line pipe, existing mill capacity for this noncritical item is sufficient to make its consideration extraneous to this report. Consumption of line pipe is estimated to be between 0.2 and 0.3 million tons per year during 1979-1981, growing to almost 0.4 million tons in 1990.

Potential Constraints

There are several potential constraints which could limit or prevent the industry from making the expansions of domestic capacity that are required to support the conclusions reached by this study.

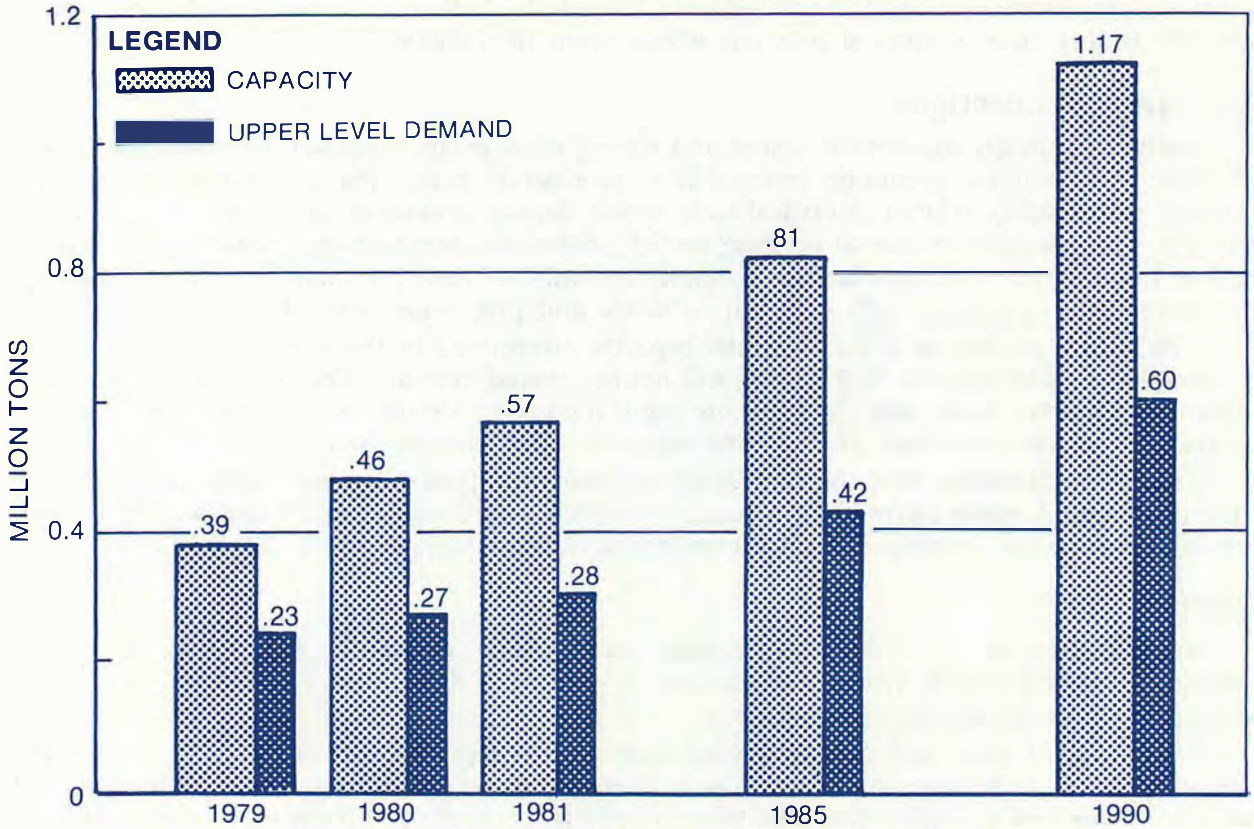


Figure 20. Proprietary Connections Capacity vs. Projected Domestic Consumption.

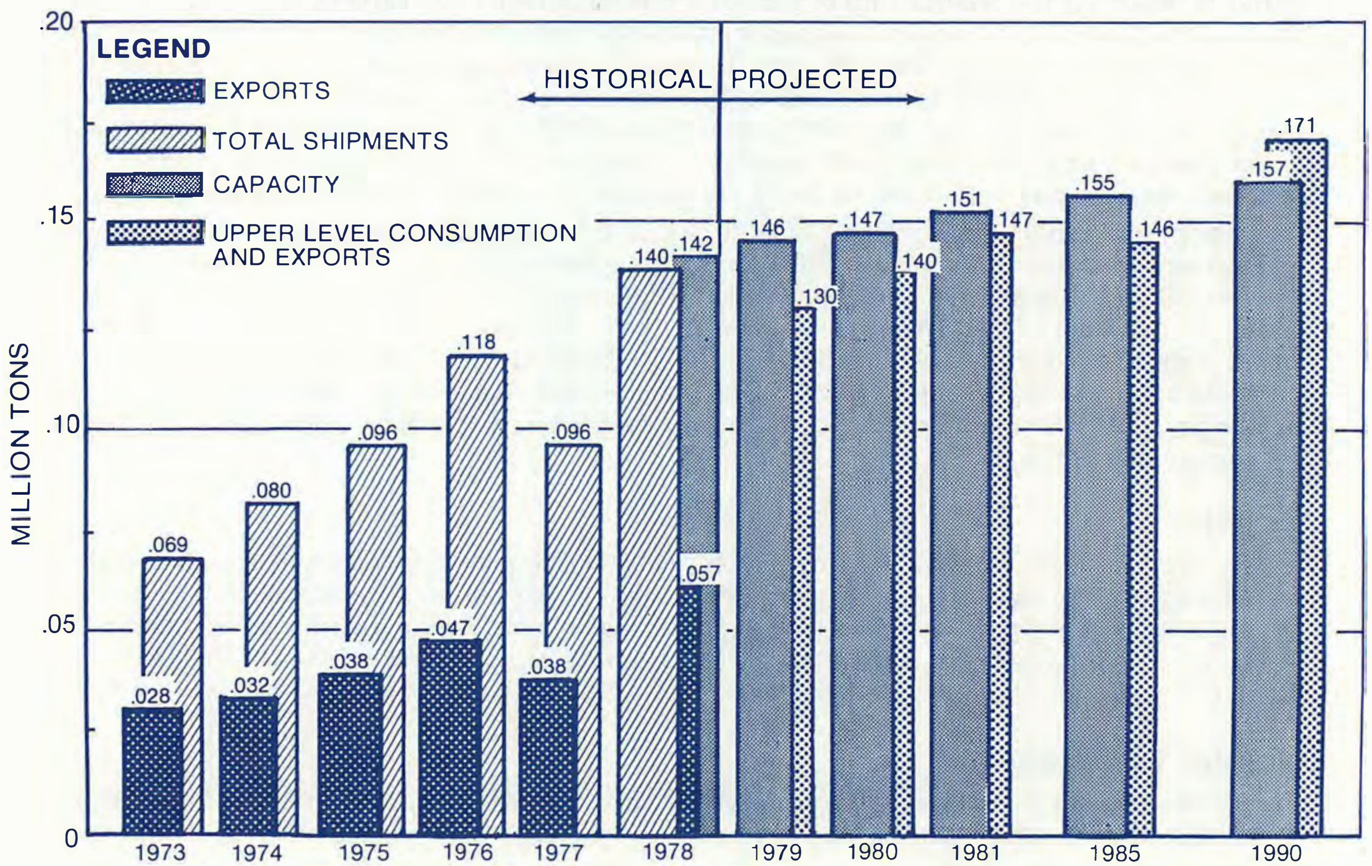


Figure 21. Drill Pipe — Estimated Supply and Demand.

The uncertainty of growth projections for the OCTG market does not encourage steel manufacturers to commit themselves to the heavy capital expenditures required for significant capacity additions. Recognizing that a major expansion involves large capital commitments and that it takes two to five years for such an investment to come on stream, factors which add to existing uncertainties become disincentives. Two of the factors which act as disincentives are:

- The lack of a federal energy policy which clearly provides the incentive to oil and gas producers to create a steady and reliable increase in drilling activity at rates which would justify steel mill expansion in time to supply increased demand
- The dramatic increase in low-priced imported casing and tubing, which has resulted in a lower demand for domestic product. Therefore, production rates from U.S. mills were well below their capabilities throughout most of 1979.

In addition to these market uncertainties, governmental constraints on the domestic steel industry and total reliance on the trigger price mechanism to restrict imports of foreign steel have reduced the amount of steel available for peak market demand and are restricting the expansion needed for normal growth. Briefly stated, these government constraints are as follows:

- Capital formation is restrained by price controls and tax policies that do not reflect replacement costs.
- Capital recovery curtailments and reduced productivity come from mandated health and safety regulations which often have more stringent requirements than are necessary for the achievement of the desired level of protection.
- Government-mandated expenditures to meet environmental pollution regulations are expected to drain 30 percent of the facility dollars to be spent by 1985. In addition, those same regulations when applied to existing marginal steel-making facilities (formerly used only in peak demand) have in the past forced them to be shut down and dismantled and will continue to do so in the future.

Recommendations

The federal government should review its impact on the petroleum and steel industries and implement action to ensure that no tubular restraints on upper limit drilling will occur.

- Energy Policy. The President and the Congress should do everything possible to support the Department of Energy's attempt to develop a sound, supply-oriented energy program that relies on the free market system to accelerate domestic drilling for oil and gas in the United States at a reliable and predictable rate.
- Capital Formation. Legislation that would accelerate capital recovery is needed in order to encourage needed capacity expansions that would head off possible shortfalls or undesirable dependence on imports in oil country tubular goods.

Observations

While the National Petroleum Council is not in a position to make recommendations beyond its own industry expertise, it is apparent from responses to questionnaires that the steel industry, as well as those industries dependent upon it, is concerned about the ability of the domestic steel industry to provide the basic steel and products required. Currently, steel is in adequate supply; however, forecasts conclude not only a domestic supply/demand pinch, but a shortfall in the free foreign world over the longer term.

Responses can be summarized as follows:

- In the meantime, the steel industry favors proposed legislation to implement in U.S. law the Multilateral Trade Negotiations (MTN) as a major step in the direction of freer, fairer trade.
- Improvement of anti-dumping laws is cited as important to the well-being of the industry not only to minimize dependency on foreign products, but to encourage domestic expansion.

- The industry stresses a need for the Environmental Protection Agency to encourage the use of the best practical demonstrated technology to attain realistic, economically feasible goals.
- The industry suggests that Congress ensure that its efforts to streamline the Environmental Impact Statement process are carried out and that no agency extend the period allowed for comments on the Environmental Impact Statement.

Chapter Five
Production Equipment

Introduction

Oil and gas production equipment (excluding well tubulars) is that equipment used to transport oil and gas from the subsurface, through surface separation and treating facilities, and on to oil and gas sales points. Details of the various types of production equipment and how they fit into the operation of an oilfield are found in Appendix C. The 1974 study identified potential shortages in materials (steel, forgings/castings, and machine tools) and manpower (skilled labor in particular) which could become constraints. It has been learned from this study that these items are still in tight supply in the production equipment industry, but this shortage has not caused any constraints in oil and gas exploration and development activities.

Today, there is again concern throughout the industry that these 1974 areas of concern will inhibit long-term capacity expansion. Equipment manufacturers are particularly concerned about long-term domestic steel mill capacity. They also need an improved and predictable domestic business climate so that firm capacity expansion plans can be developed and implemented.

At the present time, the utilization of manufacturing capacity ranges from 65 percent to 95 percent, with most industry segments operating in the 80 to 85 percent range. Backlogged orders are normal, ranging from one to nine months, with three months being most typical. This represents normal manufacturing time for most commodities in the equipment industry.

The conclusions regarding production equipment are based on the results of aggregated questionnaire responses of key equipment manufacturers. In all, about 50 percent of the more than 200 companies surveyed responded to the questionnaire. Companies directly related to oil and gas industry support had typical response rates of 65 percent, with some industry segments as great as 85 percent. The response to the questionnaires provided well documented capacity data and growth projections, along with general views and comments from the production equipment industry (Table 17).

In addition to the general assumptions noted in the section of the Summary entitled *Approach to the Study*, the production equipment capacity evaluation also assumed that, in terms of equipment size, pressure rating, specialty alloys, etc., the product mix will either remain reasonably constant or change very gradually.

Analysis and Results

The following section provides the results of individual capacity analyses of the major segments comprising the overall production equipment industry. (See Appendix I for well completion and operating well data.)

Offshore Platforms: Fabrication

Offshore platform construction yard capacity and the availability of offshore derrick barges are not likely to constrain the growth of U.S. offshore drilling and production activity. With the

TABLE 17

PRODUCTION EQUIPMENT MANUFACTURING CAPACITY GROWTH RATE SUMMARY AND COMPARISON
(Compound Annual Growth Rate—Percentage)

	1973–1978	1979–1981	1982–1990
Industry Segments *			
Offshore Platform Fabrication	23	3.9	3.0
Prime Movers	Not Surveyed	20	–
Electrical Equipment	Not Surveyed	2.2	1.5
Valves and Wellheads	19	4.4	3.1
Surface Oil and Gas Handling Equipment	10	6.5	2.7
Production Chemicals	11	11	3.1
Artificial Lift Equipment	12	6.9	2.6
Subsurface Production Equipment	11	12	7.5
Key Industry Parameters †			
Well Drilling (all wells)	11.7	6	2.9
Operating Oil Wells	0.75	1.3	1.2

* The 1973-1978 data are based on reported actual domestic plants output; the data for the periods 1979-1981 and 1982-1990 are based on reported future expansion plans. Note: The current uncertainty in the domestic petroleum industry is reflected in the low growth rate projections shown for 1982-1990. Thirty-five to forty percent of the manufacturers showed zero growth (constant capacity) beyond 1981, citing the above reason.

† 1973-1978 data are based on the API statistics; data for future time periods are based on Table I-1, Appendix I.

planned additions reported by the platform fabrication industry, construction yard capacity will be greater than projected demand through 1990. Table 18 shows planned U.S. fabrication yard capacity compared to projected platform demand. By 1978, fabrication capacity had increased nearly threefold above 1973 levels. During this same time, demand, as measured by tonnage, only doubled. As a

TABLE 18

U.S. OFFSHORE PLATFORMS: PROJECTED REQUIREMENTS AND PLANNED YARD CAPACITY

	U.S. Offshore Platform Fabrication Requirements * (tons)	U.S. Fabrication Yard Capacity (tons)	Capacity Utilization † (percentage)
Historical			
1973	145,000	157,000	92
1977	225,000	371,000	61
1978	284,000	439,000	65
Projected			
1979	311,000	455,000	68
1980	339,000	489,000	69
1981	367,000	492,000	75
1985	478,000	536,000	89
1990	617,000	641,000	96

* The annual rate of growth is about 28,000 tons per year. This is the rate of growth during the high period of 1973-1978 and is extrapolated to 1990.

† Capacity utilization percentage = 100 X (fabrication requirements/yard capacity).

result, 1978 capacity utilization stood at about 65 percent. Future platform fabrication requirements were extrapolated at the average annual U.S. growth rate established between 1973 and 1978 of 27,800 tons per year. This increasing annual tonnage results from several factors: platform size increases due to installation in progressively deeper average water depths, harsher climatic and/or sea floor conditions, and provisions for more wells per platform. This should more than offset a possible decrease in the number of platforms as the industry moves into frontier offshore basins. Additionally, a number of smaller platforms will continue to be added as higher crude oil and gas prices make heretofore marginal prospects economically attractive. Based on this tonnage extrapolation, utilization of planned construction capacity will remain less than 90 percent through 1985. Based on 1973-1978 drilling and platform installation experience in the Gulf of Mexico, the Table 18 extrapolation of fabrication requirements exceeds the tonnage needed to support the projected level of offshore drilling activity (Appendix E, Table E-3). Thus, offshore platform fabrication capacity should not be a constraint through 1990.

Offshore Platforms: Installation

The current surplus of derrick barges used in the offshore phase of platform construction should continue through 1990 (Table 19). At the end of 1978 there were 18 derrick barges, each with crane capacity of greater than 200 tons, operating in U.S. waters. (Smaller barges were excluded due to their limited utility in platform installation.) This represents an increase of nine barges, or 100 percent, since 1973. Based on operating experience in the Gulf of Mexico, with allowances for such variables as barge maintenance, platform type and size, and weather standby time, each derrick barge can install 10 platforms per year. The 82 platform installations in U.S. waters during 1978 indicate that only 46 percent of total derrick barge capacity was used.

The anticipated derrick barge surplus is contingent on these barges remaining in U.S. offshore areas. Derrick barges, like offshore drilling rigs, are highly mobile and can be employed in marine construction on a worldwide basis. However, unless a significant worldwide increase in offshore activities of North Sea magnitude occurs, the availability of derrick barges in U.S. offshore areas should be unaffected.

TABLE 19

COMPARISON OF FIXED PLATFORM INSTALLATIONS TO DERRICK BARGE INSTALLATION CAPACITIES

	Platform * Installations (no. of platforms)	Derrick Barges † Installation Capacity (no. of platforms)	Capacity Utilization (percentage)
Historical			
1973	35	90	39
1977	72	110	65
1978	82	180	46
Projected			
1979	90	200	45
1980	100	210	48
1981	110	210	52
1985	150	220	68
1990	200	220	91

* Actual installations are from *Offshore Oil Scouts Statistical Review*. The number of platform installations is based on extrapolating the 1973-1978 annual increase of 10 platforms per year. This represents an upper limit. Offshore drilling has been about 100 wells per year with about 600 completions/year.

† Number of barges from questionnaire response; capacity derived from using 10 annual installations per barge.

Platform demand which could result from acceleration of the Outer Continental Shelf (OCS) lease sales can probably be handled without constraints due to the surplus fabrication yard and derrick barge capacity. Lead times for regulatory and permitting requirements and for the exploration and delineation of any discoveries are lengthy and result in ample time for expansion of capacity by the offshore construction industry.

Although the offshore construction industry will have adequate capacity for projected growth, supplies of steel and more restrictive regulatory factors have the potential to result in material and equipment constraints. Steel is used almost exclusively in the fabrication of offshore platforms. The demand for steel products was strong during 1978 and has continued to be strong in 1979. According to *Purchasing* magazine, U.S. steel mills were running at 85 to 90 percent capacity in early 1979.[1] Although overall steel demand abated somewhat toward the end of 1979, the longer range outlook worldwide (through 1985) suggests a growing concern as to steel availability unless steel industry expansion plans are undertaken to a greater degree than is now known, especially in the United States.

The industry's ability to provide the construction capacity indicated by this analysis is contingent upon the assumption that regulatory and permitting procedures not become more restrictive. In addition, the government must announce and adhere to an OCS lease sale schedule. The slippage that has occurred from past sale schedules has been detrimental to planning expansions. For example, six Alaskan sales from the 1975 OCS sale schedule have been delayed an average of 56 months as now shown in the 1979 Department of Interior sale schedule. If clear and predictable regulatory and permitting processes were established and lease sale schedules adhered to, lead times and investment risks involved in expanding capacity could be reduced, thereby facilitating the timely addition of construction capacity.

Prime Movers

Adequate supplies of internal combustion engines and combustion gas turbine engines are anticipated. The requirements of the oil and gas industry represent only a small portion of the prime mover industry's manufacturing output. Planned expansion by engine manufacturers would increase current capacity by 20 percent per year through 1981. Long-range plans are less definitive, but it is expected that capacity will be adequate to fulfill the requirements of the oil and gas industry. Factors which could affect the total supply of engines include the availability of adequate supplies of steel alloys containing chromium and cobalt, and evolving regulatory standards. The chromium and cobalt supply is sensitive to the restrictions on trade with the African countries which mine these minerals. Engine emission standards and other regulations which require substantial expenditures by industry (e.g., federal engine testing and silencing regulations) do nothing to improve product efficiency. Their effect, however, is to reduce capital otherwise available for expansion and increase the risk that an acceptable return on investment in new capacity will be achieved, thereby discouraging expansion.

Electrical Equipment

Constraints due to the shortage of availability of electrical equipment are unlikely. The oil and gas industry's requirements represent a relatively small portion of the electrical industry's total manufacturing output. This industry is presently working at approximately 74 percent of its total capacity, and manufacturers are planning capacity additions of 21 percent between 1979 and 1990. Although supplies available for petroleum industry demand will depend on demands from other industry sectors (i.e., housing, automotive, general industrial support, appliances, etc.), there is no indication that equipment available to the oil and gas industry will restrict activity levels.

Valves and Wellhead Equipment

The reported plans of a major number of valve and wellhead equipment manufacturers indicate that this industry segment should not limit oil and gas development through 1990. This conclusion is subject to certain areas of concern which could prevent full achievement of expansion

[1] *Purchasing*, April 1978, p. 63.

plans. Foremost among the materials-related concerns are the strength of foreign demand, the potential for a shortage of steel castings and forgings, and the long lead times for delivery of machine tools.

During the 1973-1978 drilling boom, U.S. valve and wellhead equipment manufacturers nearly doubled their production capacity and increased domestic sales of equipment units by more than 100 percent. This growth is shown in Table 20 for each of the three product groups included in this industry segment. Also shown is a comparison of projected domestic demand and U.S. manufacturers' plans for increasing their capacity through 1990.

TABLE 20

VALVE AND WELLHEAD EQUIPMENT: DOMESTIC DEMAND AND PRODUCTION CAPACITY (THOUSANDS OF PIECES OF EQUIPMENT)

	Wellhead Equipment *		Christmas Tree Valves and Accessories †		Production Facility Valves	
	U.S. Demand	Capacity§	U.S. Demand	Capacity	U.S. Demand	Capacity
Historical						
1973	7.9	15.4	32.3	49.2	—Insufficient Data—	
1977	13.9	26.5	57.6	95.6	521.1	692
1978	17.6	28.9	66.7	93.4	614.2	801
Projected						
1979	18.7	30.4	67.2	97.1	627.2	809
1980	19.9	33.4	71.4	100.2	666.4	784
1981	20.9	36.9	75.6	108.1	705.6	794
1985	25.3	41.9	84.0	124.7	784.0	836
1990	27.1	50.6	102.9	157.4	960.4	906
Export Percentage of 1978 Equipment Manufactured	28.6%		25.7%		18.2%	

* Casing heads, spools, and tubing hangers.
† Individual tree components.
§ From 1973-1978, much of what appears to be excess capacity was exported. The percentage of equipment production exported in 1978 is given for reference.

Demand projections were made based on usage factors computed from 1978 domestic product sales divided by either:

- 1978 wells drilled to compute wellhead usage, or
- 1978 wells completed as producers to compute Christmas tree and production facility valve usage.

For reference, the computed usage factors are:

- 0.36 API wellheads per well drilled
- 2.1 Christmas tree valves per completed producer
- 19.6 production facility valves per completed producer.

The usage factor for wellheads of 0.36 API wellheads per well drilled appears low as wellheads are used in all wells drilled to connect blowout prevention equipment during drilling. However, this is probably reasonable for a usage index based on manufacturer sales of new equipment. This does not account for annual variations in user inventories, re-use of equipment from dry holes and abandoned wells, and importation of foreign equipment.

Although the usage factor of 2.1 Christmas tree valves and accessories per well completed appears somewhat low, it would probably be higher and appear more reasonable if wells such as rod-pumped wells, which do not use complex Christmas trees, were identifiable and segregated from the completed well count. However, this usage index is essentially the same for 1973 and 1978, indicating that reasonable projections could be made with it.

Usage of production facility valves was indexed at 19.6 valves per well completed. Although not all valves sold are used in new facilities for new wells, it is difficult to relate them specifically to new well completions (many are used for replacement of valves in existing wells; some go to non-oilfield use in refineries and petrochemical plants). The relationship between all valves sold and wells completed during 1977 and 1978 was about the same, indicating that the 19.6 valves per well completed is a reasonable indexing factor.

These usage factors were multiplied by the Outlook upper level of drilling activity to calculate projected future demand. This demand was compared to the projected future manufacturing capacity obtained from the industry survey. Table 20 also shows that before exports, U.S. manufacturers' planned capacity exceeds projected demand through 1990, except for production facility valves. The table shows that 1978 manufacturing capacity could meet growth in domestic demand through 1985, but at the expense of the export market. Valve supplies could potentially become a constraint in the 1979-1981 period if export demand is equal to or greater than the 1978 levels. However, if the 1973-1978 decreasing trend in the percentage of U.S.-manufactured equipment exported continues, this should not be a problem. With respect to production facility valves, a shortfall of six percent is indicated by 1990. In addition, should there be significant expansion in the downstream sector of the oil industry, plus synfuel development, the demand for these kinds of valves would increase substantially both for the short and long range. It should be noted, however, that the bulk of these valves are standard industrial types. Additions to manufacturing capacity are relatively simple and do not require new design or manufacturing process changes. Castings and forgings will likely be more of a constraint than general manufacturing capacity.

Steel castings and forgings are in short supply, and near-term lead times are expected to lengthen as demand rises. OSHA and EPA requirements have forced many small foundries to close; these requirements also restrict the expansion of the industry. Valve manufacturers also express concern that inadequate steel mill output could limit supplies as well, thereby constraining manufacture of valves and wellheads over the longer term.

Machine tool lead times are long, particularly for automatically controlled equipment. Should these lead times increase, they could prove to be a constraint to the addition of new capacity planned through 1985.

Surface Oil and Gas Handling Equipment

Planned expansion of manufacturing facilities for surface oil and gas handling facilities, described in Appendix C, will be sufficient to meet projected domestic and anticipated export requirements. Domestic requirements for oil and gas handling equipment have increased from 39.6 million tons in 1973 to 84.5 million tons in 1978. During this period, manufacturers operated at an average of 84 percent capacity. When referenced to new oil and gas wells completed, 1973-1978 demand was approximately 2.5 tons per new well completed. Future demand, projected at 2.5 tons per new well completed at the upper level of the activity range, remains substantially below manufacturers' projected capacity. Table 21 shows that through 1990, planned additions to capacity will result in sufficient spare capability to continue meeting the historical export rate (10-20 percent of capacity) plus additional spare capacity to support unforeseen growth in either domestic or foreign demand.

As with valves and wellheads, manufacturers in this industry segment are concerned for future supplies of steel castings and forgings and the component parts made from them.

Water Treating Equipment

Manufacturers of this equipment have considerable excess capacity; capacity utilization in 1978 was 65 percent. In addition, manufacturers of this equipment supply several other industries. The combination of these two facts supports the conclusion that water treating equipment for produced and injected water will not constrain oil and gas industry activities.

TABLE 21

SURFACE OIL AND GAS HANDLING EQUIPMENT

	U.S. Requirement (thousand tons)	Manufacturing Capacity (thousand tons)
Historical		
1973	39.6	55.9
1977	69.7	99.5
1978	84.5	106.4
Projected		
1979	80	115
1980	85	125
1981	90	134
1985	100	149
1990	122.5	170

Steam Generation Equipment

There is sufficient manufacturing capacity for steam generation equipment to support future oil and gas industry requirements for thermal tertiary recovery projects. Manufacturing capacity could be affected by the market setback this industry segment recently experienced. The economics of meeting air quality regulations have restricted and even caused the shutdown of some thermal recovery projects in California. Currently, decontrol of heavy oil has improved the economics of thermal recovery projects. However, steam generator manufacturers will not have a satisfactory market for their equipment until air quality goals and regulations stabilize. Ultimately, manufacturing capacity may be diverted to production of other types of equipment or, in the extreme, some of the smaller manufacturers may reduce capacity or close down, as was the case with small foundries in the early 1970's.

Pumps and Compressors

The availability of pumps and compressors should be sufficient for oil and gas drilling and production requirements. Current capacity is adequate (1978 pump capacity utilization was 94 percent; 1978 compressor capacity utilization was 71 percent), and manufacturers' backlogs are about normal, ranging from one to six months. Table 22 compares manufacturers' planned capacity growth rates to rates of growth experienced and projected for oil and gas drilling activity. Plans for capacity additions plus the fact that oil and gas drilling and production represent only a portion of the market for manufacturers of pumps and compressors support the conclusion that adequate supplies of pumps and compressors will be available through 1990.

TABLE 22

DOMESTIC PUMP AND COMPRESSOR MANUFACTURING CAPACITY GROWTH
(Compound Annual Growth Rate—Percentage)

	Pumps	Compressors	Wells Drilled
1973–1978	17.8	13.1	11.2
1979–1981	5.6	10.8	5.9
1982–1990	6.9	0.1*	3.0

* This growth should present no problems as current capacity is underutilized and lead times for timely expansion should be adequate if incentives are clear.

Potential shortages of steel products (sheet, tube, and alloys plus castings and forgings) could restrain utilization of existing capacity and alter plans for addition of future plant capacity. Large castings and forgings are particularly critical.

Artificial Lift and Subsurface Production Equipment

Planned capacity growth in this industry will support oil and gas industry growth at the upper limit activity level. In fact, several product groups could have excess capacity. This equipment serves two markets: equipping of new wells completed, and maintaining production from active producers. The primary market is maintenance of existing wells. Although drilling activity is projected to grow at 5.9 percent per year from 1979-1981, growth in the number of active producing wells is projected at only one percent per year. Planned capacity for most of the product groups shown on Table 23 is projected to increase at a rate greater than active oil and gas wells, both in the near and the long term. A few of the individual product groups show relatively slow growth (one to two percent) in the 1982-1990 period. However, these are groups which now have excess capacity and require only minimal growth.

This industry segment is not currently constrained, but the manufacturers surveyed indicated concern for potential shortages of selected steel alloys. Of particular concern are those containing chromium and cobalt, again because of the import restrictions placed on materials from selected African countries.

TABLE 23
ARTIFICIAL LIFT AND SUBSURFACE PRODUCTION EQUIPMENT MANUFACTURING CAPACITY
(Compound Annual Growth Rate—Percentage)

	1973–1978	1979–1981	1982–1990
Artificial Lift Equipment			
Rod Pumps	8.5	4.5	1.9
Sucker Rods	9.8	5.2	1.8
Miscellaneous Sucker Rod Equipment	14.9	3.6	0.3
Pumping Units	15.3	11.0	1.7
Submersible Pumps	12.3	10.4	7.1
Gas Lift Mandrels	30.5	15.2	4.2
Gas Lift Valves	20.8	16.9	4.1
Tubing Anchors	6.1	9.4	7.1
Subsurface Production Equipment			
Packers	3.5	10.8	10.2
Tubing Accessories and Wireline Equipment	3.4	21.9	16.6
Bridge Plugs and Retainers	1.9	4.3	3.4
Safety Valves	14.1	15.4	10.0
Liner Hangers	8.9	11.8	7.3
Polished Bore Receptacles	–	6.2	4.6

Production Chemicals

Production chemical manufacturing capacity will exceed projected demand through 1985. Manufacturers are concerned that supplies of petroleum feedstocks may constrain their output in the late 1980's.

This industry segment cannot be readily measured against wells drilled or completed. Demand for production chemicals is related to aggregate production (oil, water, and gas) flow streams. With continuing increases in water volumes produced with oil and gas, and as enhanced recovery operations conceivably increase, usage of production chemicals should increase. As a result, demand was projected at an annual growth rate of nine to 10 percent. This is based primarily on recent growth in demand. To put it into perspective, demand is expected to double by 1985 and triple by 1990. Table 24 shows that projected demand remains comfortably below manufacturers' plans for production capacity through 1981. Beyond 1981, projected demand grows more rapidly than planned capacity so that capacity utilization in excess of 90 percent is projected by 1985, with potential shortages developing thereafter.

TABLE 24

PRODUCTION CHEMICAL INDUSTRY

	Demand		Capacity	
	Gallons * (millions)	Growth Rate † (percentage)	Gallons * (millions)	Growth Rate † (percentage)
Historical				
1973	31	–	45	–
1977	48	11.5	62	8.3
1978	53	10.4	75	21.0
Projected				
1979	58	9.4	79	5.3
1980	63	8.6	81	2.5
1981	69	9.5	102	26.0
1985	100	9.7	107	1.2
1990	155	9.2	134	4.6

* Includes all chemicals used: demulsifiers, water treatment chemicals, corrosion inhibitors, etc.
† Compound annual growth rate.

The reason for this low capacity growth rate from 1981 to 1985 is that several manufacturers either indicated no plans for capacity increases or did not respond to the capacity questions for the years 1985 and 1990. These manufacturers felt they were unable to make a reasonable projection of their capacity without having some relatively firm information on long-term plant feedstock availability. With present technology, the basic feedstock is petroleum derived. In an effort to prevent potential shortages, the chemicals industry is working to find alternate materials for feedstocks and reduce its reliance on petroleum-derived materials.

It is doubtful that a shortage of these chemicals would physically constrain oil and gas exploration and development activity. In fact, with most domestic fields in a mature phase of operation, growth in demand should stabilize. In a shortage situation the available chemicals would be used according to economic priorities, particularly those needed for secondary and enhanced recovery projects.

Potential Constraints

Although no long-term constraints are anticipated in supporting the Outlook upper level of possible domestic drilling activity, the following potential constraints were identified which could alter or restrain the plans of manufacturers to make timely additions to their current capacities:

- OSHA and EPA requirements have forced many small foundries to shut down and have restricted expansion in this industry. As a consequence, manufacturers express concern at the continuing shortage of castings and forgings. This looms as a potential constraint for the availability of valves, wellheads, and other production equipment.
- Although not a constraint in the near term, manufacturers are concerned that steel supplies (raw steel for castings and forgings, plate steel, structural shapes, and pipe) may become a constraint to their ability to add the capacity they are now planning.
- A shortfall in the supply of steel alloys containing chromium and cobalt could become a constraint because of the import restrictions placed on materials from selected African countries.

- Long lead times for machine tools, particularly for automatically controlled equipment, could be a constraint to the expansion of capacity to manufacture valves and wellhead equipment after 1985.
- Production equipment manufacturers are concerned that there may be shortages of the energy needed to operate their plants in the future. This risk could adversely affect some plant expansion decisions.
- Increasing regulation of the petroleum industry and associated supply and service industry is a serious potential constraint. Regulations affect manufacturers by increasing costs without increasing output. The resultant lower profitability of operations, coupled with the added risk of additional future regulations, seriously diminishes the incentive to invest in new capacity.

As mentioned above, these are potential constraints. Given a predictable governmental regulatory and domestic business environment, the equipment industry can support the upper level of projected oil and gas industry activity.

Chapter Six
Well Servicing

Introduction

The well servicing industry is composed of a wide diversity of manufacturers, contractors, and suppliers. These diverse services and materials are required in different combinations in the process of drilling and completion of new oil and gas wells; in the stimulation, repair, and maintenance of existing wells; in the conversion of producing wells to injection status; and in the abandonment of wells after their utility erodes. The services provided by these contractors are necessary both in development of new oil and gas fields as well as in the maintenance of existing producing fields. The various services and equipment are described in some detail in Appendix C.

In the 1974 NPC study, service rig availability was identified as the most critical factor in the well servicing industry for the 1974-1976 period. That study projected an increase of operating rigs of five to six percent per year through 1976. Demand for these rigs was expected to increase about 25 percent per year after 1973. Actual growth in the service rig census was actually only about 4.5 percent per year through 1978. However, this was sufficient to meet demand, which escalated at a rate of three to four percent annually during this period. The 1973-1974 high demand for service rigs declined in 1975 following the end of the Arab oil embargo and was also negatively affected by the termination of the depletion allowance in 1975. The estimated 1974 field utilization rate of 91 percent was not sustained and currently stands at about 77 percent of available service rigs.

For the current study, efforts were directed towards evaluating future constraints on petroleum industry activity levels as a result of potential shortages of well servicing rigs, well services, materials, and/or manpower. In this regard, the participants focused mainly on the period 1979 through 1981, but included evaluation for the years 1985 and 1990. Analysis and review of the following areas were undertaken:

- Determination of specific service rig manufacturing capacities for present and near-term future periods
- Determination of services and supply capacities in the functional areas of well cementing, well stimulation, and specialty tools and testing services
- Determination of possible constraints caused by insufficient mobility of either equipment, supplies, or services due to inadequate transportation or lack of trained manpower
- Review of other potential constraints which could develop into capacity limitations on present or future oil and gas development and exploration activity
- Review of recommended solutions to identified problems.

Inasmuch as the well servicing industry covers a broad array of functions and services, the current study is an attempt to focus on the most important functions in broadly grouped categories. These categories cover an estimated 90 percent of the manpower requirements and capital spent by the well servicing industry. These specific categories include well servicing rigs and services, cementing and stimulation services, specialty tools and services, and transportation, including land, air, water, and rail.

Because the well servicing industry is so diverse in services and distribution locales, it is impossible to gather industry data on all or even a majority of the individual industry services provided. Only an estimated 10 services are provided by any one company, as compared with over 50 available industry-wide. Additionally, there is no trade association which addresses or maintains records on all of the services provided in the oilfield. To generate the necessary quality of forecasts in the specialized services, the study participants were chosen based on their industry expertise in each of the five categories listed above. These individuals represent management and technology leaders in their particular services. Questionnaires were used to survey the majority of the service rig industry's manufacturing capability. Surveys also reached the leading representatives in the cementing and stimulation service industry as well as specialties, services, tools, and testing. In addition to the formal questionnaires, personal interviews with marine and vehicle manufacturing companies and offshore drilling companies were conducted to determine the capability of transportation with respect to manpower and material flexibility. Interviews were also held with management representatives of rig manufacturing companies, well servicing contracting companies, and tool manufacturers and contractors.

Analysis and Results

Three separate questionnaires were designed and tailored specifically for well servicing rig manufacturers, cementing and stimulation services companies, and specialty tool manufacturers and service companies. The questionnaires were designed specifically to address the following:

- Historical manufacturing capacity
- Current manufacturing capacity
- Planned manufacturing capacity
- Percent utilization of each of the above
- Future potential constraints on planned manufacturing capacity
- Projected personnel availability.

Six of the seven companies surveyed, representing 85 percent of the well service rig manufacturing industry, responded to the survey. Seventy-five percent (six of eight major companies surveyed) responded to the survey of the specialty tools and services industry. The cementing and stimulation industry survey included eight major companies involved in technical sales, services, and research; five companies responded. Overall participation in the questionnaire phase of the data compilation was 74 percent (17 of 23 companies), thus providing a substantive base for the activity projections.

Well Servicing Rigs

Historical figures indicate that service rig manufacturers have increased both their capacity to produce and their utilization of that capacity over the period 1973-1978 in response to increased oil industry demand. According to *World Oil*, service rigs manufactured in the United States increased yearly, from 162 rigs in 1974 to 539 in 1978 (Table 25). Total manufacturing capacity was increased at a compound annual growth rate of 25 percent during the five year period. During this same period, capacity utilization increased from about 60-68 percent to over 90 percent. This performance resulted in a rig count of approximately 4,000 service rigs operating in the United States at year-end 1978.[1] Of all rigs fabricated over the 1974-1978 period, 86 to 90 percent were added to the domestic supply, with the remainder going to the international operations.

Currently, service rig manufacturers are operating at an even greater utilization of their manufacturing capacity (about 93 percent). This is being achieved by working 12 hours daily for five days a week. Capacity can be increased only slightly by adding shifts due to maximum machinery utilization limitations. However, the manufacturers advise that they plan capacity increases after 1979 ranging from two to four percent annually. The only exception is 1981, when manufacturers plan a 13.4 percent increase in capacity. They advise, however, that this large one-time

[1] Association of Oilwell Servicing Contractors.

increase is due to anticipated demand from the foreign sector. Also, it reflects a decrease in drilling rig manufacturing as several manufacturers use the same machinery and personnel to fabricate both types of rigs.

TABLE 25

SERVICE RIG INDUSTRY—DEMONSTRATED MANUFACTURING CAPACITY

Rated Capacity	1974 Total	1974 Domestic	1974 Export	1975 Total	1975 Domestic	1975 Export	1976 Total	1976 Domestic	1976 Export
(Recommend Depth Wet String—2½" Tubing)									
0- 3,500 ft.	12	11	1	18	15	3	14	9	5
3,501- 7,000 ft.	19	10	9	24	19	5	38	30	8
7,001-10,000 ft.	9	8	1	8	5	3	80	77	3
10,001-12,000 ft.	90	87	3	106	93	13	113	99	14
Over 12,000 ft.	32	30	2	58	52	6	96	89	7
Total	**162**	**146**	**16**	**214**	**184**	**30**	**341**	**304**	**37**

Rated Capacity	1977 Total	1977 Domestic	1977 Export	1978 Total	1978 Domestic	1978 Export
0- 3,500 ft.	13	13	–	6	6	-
3,501- 7,000 ft.	31	22	9	30	26	4
7,001-10,000 ft.	37	19	18	54	35	19
10,001-12,000 ft.	230	217	13	171	255	9
Over 12,000 ft.	101	82	19	278	235	23
Total	**412**	**353**	**59**	**539**	**484**	**55**

SOURCE: *World Oil.*

Assuming that capacity utilization reaches a limiting efficient rate of 97 percent in 1979 and remains at that level throughout the projected years, the U.S. service rig count will be affected as shown in Table 26. Projections were made for the worst possible case; that is, exporting 30 percent of all service rigs manufactured after 1980 and retiring four percent of the total rig count annually. As shown in Table 26, growth rates of total domestic well service rigs are 7.3 percent in 1979, 6.8 percent in 1980, etc. This growth exceeds the upper level of projected drilling activity for the 1979-1990 period. Combined with the fact that year-end 1978 field utilization is only 77 percent of the available fleet, a shortage in the availability of service rigs will not constrain petroleum industry activity.

Cementing and Well Stimulation Services

The cementing and well stimulation industry has demonstrated a remarkably flexible performance over the past five years. The fluctuating demands of the petroleum industry have presented a formidable but achievable supply situation in this service segment. This is probably due to these service companies' diversification in distribution locales and their ability to build up bulk inventories rapidly. Table 27 represents a sampling of the major U.S. well cementing and stimulation companies. This shows historical growth rates in items peculiar to this industry. As shown, this industry segment responded to demand over the 1975-1978 period by realizing categorical growth rates exceeding 11 percent annually. In analyzing the response to equipment needs, it appears that the increased demand for fracture stimulations, especially planned massive fracture jobs, spurred the stimulation service companies to grow in equipment acquisitions at rates exceeding 20 percent

TABLE 26

WELL SERVICE RIG DELIVERIES

	1974	1975	1976	1977	1978	1979	1980	1981	1985	1990
Total Capacity	238	288	424	475	583	543	595	675	785	868
Percent Utilization	68.0	74.2	80.5	86.7	92.5	97.0	97.0	97.0	97.0	97.0
Total Deliveries	162	214	341	412	539	527	577	655	761	842
Exports	16	30	37	59	55	84	121	197	228	253
Total U.S. Rig Deliveries	146	184	304	353	484	443	456	458	533	589
U.S. Well Service Rig Census (Average Annual)										
Case I (2 percent attrition)					3.758	4,137	4,501	4,860	6.003	7,672
Case II (4 percent attrition)					3,758	4,033	4,309	4,576	5,421	6,635
Percentage Growth (Annual) in Well Service Rig Census										
Case I (2 percent attrition)					–	10	8.8	8.0	5.4	5.0
Case II (4 percent attrition)					–	7.3	6.8	6.2	4.3	4.1

TABLE 27

WELL SERVICING—INDUSTRY PERFORMANCE CEMENTING AND STIMULATION

	1975	1976	1977	1978	Compound Annual Growth Rate—Percentage
Cementing Units	953	1,197	1,302	1,422	14.3
Cement Storage Capacity (million cubic feet)	1.12	1.25	2.81	3.18	41.6
Cement Used (million tons)	1.45	1.62	1.80	1.99	11.1
Fracturing Units	464	582	690	789	19.4
Frac Unit Horsepower	399,700	534,150	646,300	749,750	23.3
Frac Blenders	210	260	316	342	17.7
Bender Capacity (BPM)	13,655	17,196	22,500	25,840	23.7
Sand Storage Capacity (thousand tons)	37.8	51.3	89.4	104	40.1
Frac Sand Used (thousand tons)	436.6	534.1	671.2	768	20.7
Acid Pump Units	229	257	292	332	13.2
Acid Pump Horsepower	72,250	80,470	92,260	110,040	15.1

per year in 1976. Therefore, given the availability of stimulation treatment materials, the service companies can expand their well treating units dramatically, with about one year lead time for planning and delivery.

Table 28 presents planned growth rates for the same cross-section of stimulation/cementing service companies in those categories available. Projected growth rates are not seen to be as great

TABLE 28

WELL SERVICING—PROJECTED NEAR-TERM ACTIVITY CEMENTING AND STIMULATION (Compound Annual Growth Rate—Percentage)

	1979	1980	1981
Cementing Units	12.9	7.4	4.4
Cement Storage Capacity	13.5	8.7	8.8
Cement Use	8.4	6.0	6.1
Fracturing Units	7.6	8.1	7.3
Frac Blenders	7.3	5.7	2.6
Sand Storage Capacity	13.0	10.4	15.0
Frac Sand Use	14.1	9.8	8.9
Acid Pump Units	12.4	7.7	16.7

over the 1979-1981 period as over the 1975-1978 period. However, with the immense build-up experienced recently combined with continued aggressive postures, the cementing and stimulation industry should not be a constraint to oil and gas well drilling activity in the United States.

Specialty Tools and Services

The diversity of the spectrum of the special tools and services industry requires some averaging of the past, current, and future capabilities of the companies providing these services. Most of the service companies reviewed in well cementing and stimulation provide many other products and services. Also, several companies reviewed in the production equipment industry manufacture special well servicing and treating tools. Therefore, proration of capacity is required in making an analysis. Industry production has increased 9-12 percent annually over the recent term, thus not constraining oil industry activity. The specialty tools industry has been able to maintain its capacity to train craftsmen in the skilled areas for producing precision parts and tools designed with close tolerances. Current capacity utilization is about 82 percent industry-wide. Plans are to increase capacity for manufacturing these special tools by 12.0 percent in 1980 and 10.4 percent in 1981. Further growth of 8.0 percent per year in the 1982-1985 period and 6.7 percent annually in the 1985-1990 time frame is projected. Coupled with available growth potential in capacity utilization, special tools manufacturing can easily grow with demand.

Transportation

There currently is an overall surplus of land and marine transportation vehicles and vessels. A slight shortage of helicopters on the Gulf Coast has been relieved by the movement of equipment from other areas and the ample supply of marine craft. Some dislocations due to regional fuel supplies have been experienced, but the industry assumes that preferential allocation measures will avoid serious future supply shortages.

Land vehicles generally will be available in adequate numbers over the next decade, although truck carrying capacity may be reduced. Shortages in railroad bulk cars are evident at present, but are localized mainly in the Rocky Mountain states. These shortages appear to be seasonal in nature as their availability depends upon agricultural requirements.

Projections of increases or decreases in marine service activity are a direct function of the drilling, production, pipelaying, and construction activity offshore. Forecasts of future activity are reflected in this segment's building programs, which include anticipated new work and replacement of certain obsolete vessels.

In early 1979, there were approximately 1,400 boats operating for the oil and gas industry in U.S. waters on or adjacent to the U.S. Outer Continental Shelf and in nearby foreign areas. This fleet consists of tugs, supply boats, and crew boats. There are about 150 more vessels of various types and sizes being built in U.S. yards. There is also a considerable inventory of U.S.-owned or controlled vessels operating in foreign areas. The present inventory of existing vessels and those under construction should be adequate to accommodate an increase of 10 to 15 percent over existing demand for their services. Any dislocations due to shortages of vessels can be minimized through the use of older vessels, the return of U.S. flag vessels now operating in foreign waters, and increased efficiency by producers in the management of their offshore supply and manpower needs.

The helicopter is the basic aircraft used in drilling and production operations. At present, there are an estimated 610 helicopters (450 classed as small, 150 medium, and 10 heavy) working for the oil and gas industry. Larger helicopters have entered the industry since 1974 in response to the requirements of longer distances in more severe operating conditions. Drilling in the Gulf of Mexico has also begun to require larger helicopters as operations are being conducted farther away from shore.

Delivery time for a medium or large helicopter is six to 12 months and slightly longer for smaller aircraft. Certain international events, however, may tend to shorten this delivery time.

Spot shortages in helicopter services can be relieved in a short time because of the extreme mobility of the equipment. For example, helicopters were recently moved from Alaska to the Gulf of Mexico in response to changing demand.

Potential Constraints

The results of the outlook projections are limited in terms of the types of additional well service requirements in the future. It is highly likely that, as enhanced recovery of existing reserves becomes more viable through technology and pricing incentives, additional wells will be needed to establish the integrity of most enhanced recovery projects. This will mean drilling in existing fields on much denser well spacing and converting large numbers of existing wells from production to injection status. This could place a severe demand upon service rig availability and movement. Pricing incentives granted thus far during 1979 will generate a much larger workover base due to improved economics. Since early 1979, service rig utilization has been outpacing drilling rig utilization in the country, with working service rigs increasing as much as four percent per month. In California, decontrol of *heavy* crude should generate a well servicing boom. This is subject to the issuance of additional steam generator operating permits. Workovers have also been buoyed by certifications into stripper, tertiary, newly discovered, and marginal crude classifications.

Emphasis is turning to the construction of deep capacity, 24-hour operation service rigs with the modified capability of drilling, logging, and cementing. With these functions, it is possible that these rigs could serve either well service or drilling operations.

Service companies almost unanimously agree that the most critical limiting factor is manpower availability. Companies are spending much time in the training of personnel, especially on-site operators and technicians, but high turnover rates are being experienced. This is reportedly due to a lessening overall desire to pursue careers which involve 24-hour callout status and working under harsh weather conditions. Service companies must compete within their industry as well as with the oil companies for qualified technical graduates, and it is difficult for them to appear as attractive to a graduate as an oil company might. Training facilities, including classroom space, laboratory access, and instructors, are not seen as a limiting factor. The top priority is to attract and train operators, technicians, mechanics, and field supervisors. In fact, the specialty tool industry plans growth in trainee level personnel of 67 percent annually over the 1979-1981 term and 15 percent per year over the 1981-1990 time frame.

Other potential constraints are summarized below.

- Service companies foresee potential near-term shortages of valves, unions (connectors), and high pressure piping. This could become critical depending upon the need and utilization of these items by the synthetic fuel industry as it develops.
- Some localized shortages of bulk supplies (cement, graded sand, acid) are anticipated in Rocky Mountain locations in 1980 and 1981. Since storage lives are limited for cement and acid, the current rail car shortage has created problems in getting materials to bulk distribution points within the service life of the materials. With a two-year lead time on new rail cars, additional spot shortages may occur in the near term.
- The cementing and stimulation industry reports that various government regulations are costing the industry approximately 3.2 percent of sales revenues in compliance costs. Department of Transportation and EPA requirements are considered by industry to be the most costly. The regulations cited most frequently include those governing the handling, transportation, and pumping of flammable materials, and driving regulations.

Chapter Seven
Manpower

Introduction

Exploration and production of oil and gas is a capital-intensive business, the success of which depends on an adequate staff of professional engineers and earth scientists backed by a competent, trained force of technicians and skilled workers. The purpose of this part of the overall study was to identify areas of potential shortages in such manpower, and to recommend corrective or preventive measures where problems can be seen or anticipated.

As in the National Petroleum Council's study, *Availability of Materials, Manpower and Equipment for the Exploration, Drilling and Production of Oil—1974-1976*, this study focused only on those occupational groups deemed critical to growth; i.e., geologists, geophysicists, engineers, technicians, offshore marine service personnel, and skilled oilfield workers.

What follows is based on information gathered and analyzed by the study participants, supplemented by other sources as referenced in the report.

Analysis and Results

Professional Personnel

Exploration and production companies employ specially trained exploration geophysicists and geologists to locate areas of potential oil and gas accumulation; production geologists to identify productive intervals and map productive zones; petroleum engineers to plan drilling procedures, oil and gas recovery programs, artificial lift, and surface and subsurface production systems; gas engineers to design gas gathering and processing systems; and civil engineers to design and build structures. This professional pool is also the prime source for operations management.

A significant part of the time of middle and lower level professionals is spent complying with the requirements of government regulations. Steps to simplify, reduce, or eliminate this burdensome reporting could increase the engineer and geologist manpower available for productive work.

While most of these professionals, except the geophysicists, are employed by exploration and production companies, a growing number are with service and supply companies, consulting firms, or are self-employed.

In response to study surveys, exploration and production companies indicated that professional personnel availability will have a growing impact on the ability to expand rapidly during the 1980-1985 period. Less than half, however, expect the impact to be large. In Chapter One it was projected that, under the most favorable business climate, the upper limit of possible wells drilled in the United States in 1981 would be about 19 percent more than in 1978. This would increase the need for geologists, geophysicists, and engineers. Projected supply and demand relating to professional personnel for exploration and production is discussed below and in more detail in Appendix J.

Earth Scientists

Geophysicists and geologists, with only a few professionals in other disciplines, make up the earth scientists' occupational group. A key indicator of need for earth scientists is drilling activity. In the United States in the six-year period 1973-1979, drilling activity in terms of wells and footage increased at a compound annual rate in excess of 11 percent (Table 29). The upward trend is expected to continue, but at a declining rate of growth, in the two-year period 1979-1981 (five to six percent yearly) and the subsequent nine-year period 1981-1990 (three to five percent yearly).

TABLE 29

DRILLING ACTIVITY TRENDS 1973-1990
(Compound Annual Growth Rate—Percentage)

	1973	Est. 1979 *	Est. 1981 *	Est. 1990 *	6 Years 1973-79	2 Years 1979-81	9 Years 1981-90	11 Years 1979-90
Average Active Rigs	1,194	2,486	2,790	4,143	13.0	5.9	4.5	4.8
Number of Wells (thousands)	27.6	52.0	58.0	75.4	11.1	5.6	3.0	3.4
Total Footage (millions)	139	261	293	435	11.1	6.0	4.5	4.8
Average Depth (feet)	5,030	5,011	5,068	5,769	−0.1	0.6	1.5	1.3
Average Wells/Rig	23.1	20.9	20.8	18.2	−1.7	−0.2	−1.5	−1.3

* Outlook upper level possible.

Geophysicists. Survey data (Appendix J) indicate that the oil and gas industry employed about 10,000 geophysicists in 1978 at the end of a two-year period in which seismic crew months, an indicator of geophysicist requirements, increased at a compound annual rate of 15.9 percent. This increase followed a two-year period during which crew months declined 9.6 percent annually (Table 30). Based on projected exploratory drilling activity and related seismic work, it is estimated that the need for geophysicists over the next decade will increase at a rate of six to seven percent yearly. This translates to a net increase of 600-700 geophysicists yearly (not covering attrition) in the early part of that period, and 1,200 to 1,300 yearly in the late 1980's, for a 1989 total in excess of 20,000. This is approximately double the 1978 level (Table 30).

Those schools awarding degrees in geophysics which were surveyed by the International Association of Geophysical Contractors in 1978 indicated present capacity to graduate about 400 geophysicists yearly. About 30 percent of the present geophysicist force is made up of such graduates. Another 30 percent are geologists, with the remainder mainly physicists, engineers, and computer scientists.

The projected reservoir of graduates in these disciplines is expected to preclude any constraint in meeting the quantity of geophysicists required. At the same time, there is a potential constraint in the early years as a result of the growing proportion of the total force having little experience. However, this should be mitigated by increased industry training and the use of computer-assisted analysis and interpretation. Acceleration of such effort may be needed to ensure that geophysicist manpower is adequate to handle the growing demand.

Geologists. Industry requirements for geologists during the study period are expected to increase because of more drilling activity and because geological interpretations have become more time consuming. Historically, the number of wells drilled per geologist has ranged between 2.5 and 3.0; the projected average is about 2.0. The rate of increase in the total number of geologists required will be six to eight percent annually in 1980 and 1981, and approximately two percent thereafter, based on industry survey data.

In recent years, oil and gas industry employers have limited their hiring of geologists mainly to graduates with advanced degrees. In the years 1979 through 1981, a survey of 30 schools indicates that the number of such graduates will be insufficient to cover needed additions to the force

TABLE 30

U.S. OIL AND GAS INDUSTRY
EXPLORATORY WELLS, SEISMIC CREW MONTHS, AND ESTIMATED GEOPHYSICIST MANPOWER REQUIREMENTS

				Seismic Crew Months			Estimated Geophysicists Required	
Drilling Year	Exploratory Wells Drilled *	Seismic Activity Year	Seismic Index (Exploratory) Wells Per Crew Month †	Number §	Compound Annual Growth Rate (Percentage)		Number	Change From Prior Year ¶
1974	8,619	1973	–	–				
1975	9,214	1974	2.37	3,888				
1976	9,234	1975	2.70	3,420	−12.0%	−9.6%/Yr		
1977	9,961	1976	3.13	3,180	−7.0%	(2 yrs)	7,900	
1978	10,724	1977	2.88	3,720	17.0%	15.9%/Yr		
1979	11,500	1978	2.69	4,272	14.8%	(2 yrs)	10,000	
1980	12,300	1979	2.59	4,749	11.2%		10,660	660
1981	13,000	1980	2.55	5,098	7.4%	6.6%/Yr	11,365	705
1985	14,900	1984	2.43	6,132		(11 yrs)	14,675	910
1990	17,900	1989	2.08	8,607			20,200	1,250

* Source: 1974-1978, *Oil and Gas Journal* Statistical Department; 1979-1990, Appendix E, Table E-17.
† 1974-1978 calculated (wells÷crew months); 1978-1989 estimated; trend reflects increasing difficulty in finding new prospects.
§ Source: 1974-1978, Society of Exploration Geophysicists; 1979-1989 calculated (wells÷seismic index)
¶ Reflects estimated increase in number of geophysicists required versus prior year. (Does not include replacements to offset attrition.)

plus estimated attrition. However, total graduates, including B.S. degrees, will be adequate to meet both requirements. After 1981, advanced degree graduates should again be adequate to meet employers' demands, with B.S. degree graduates available to meet other requirements, such as those for geophysicists. Figure 22 illustrates the projected supply/demand balance yearly for 1979-1985.

While the shortage of the availability of geologists in terms of total numbers is not expected to be a constraint, the decline in level of experience is a concern. This decline accompanies the rapid net growth seen in the total force 1975-1981, and the large segment of the present force that will be retiring in the next five to 10 years. Many geologists retiring from company employment join consulting firms or are self-employed, so their talents are not immediately lost to the industry, but employers will need to intensify training of their younger geologists to take on more responsibilities sooner.

Engineers

The Society of Petroleum Engineers (SPE) Engineering Manpower Committee published *Survey Number 2* in May 1979, showing trends in the number of engineers employed by a sampling of companies engaged in oil and gas activities. Table 31 is extracted from the SPE report.

The large increase in engineering population since 1974 is expected to continue but at a lower growth rate. The majors and the gas companies project an increase of about 15 percent in the 1978-1981 period, while the independents project a 31 percent increase, and service companies 38 percent. During this same period, the Outlook upper level drilling activity projected that 20 percent more wells and 27 percent more feet could be drilled.

Other qualifications being equal, oil, gas, drilling, and producing companies generally prefer to hire graduates with petroleum engineering degrees. The SPE report indicated that, in 1978, due to the existing shortage, companies met their new graduate hiring goals for petroleum engineers by employing graduates of other disciplines, as shown in Table 32.

The B.S./M.S. petroleum engineers hired by the companies responding to the survey represented 28 percent of total B.S./M.S. engineers hired on campus and 66 percent of the petroleum engineers desired. These companies indicated a desire that future on-campus hires be about 40 percent petroleum engineering graduates, as was their goal in 1978. In response to the demand demonstrated by high salary job offers, enrollment in petroleum engineering schools is increasing rapidly. Table 33 shows the projected available graduates of petroleum engineering schools compared with the projected numbers that companies will desire to hire from these schools.

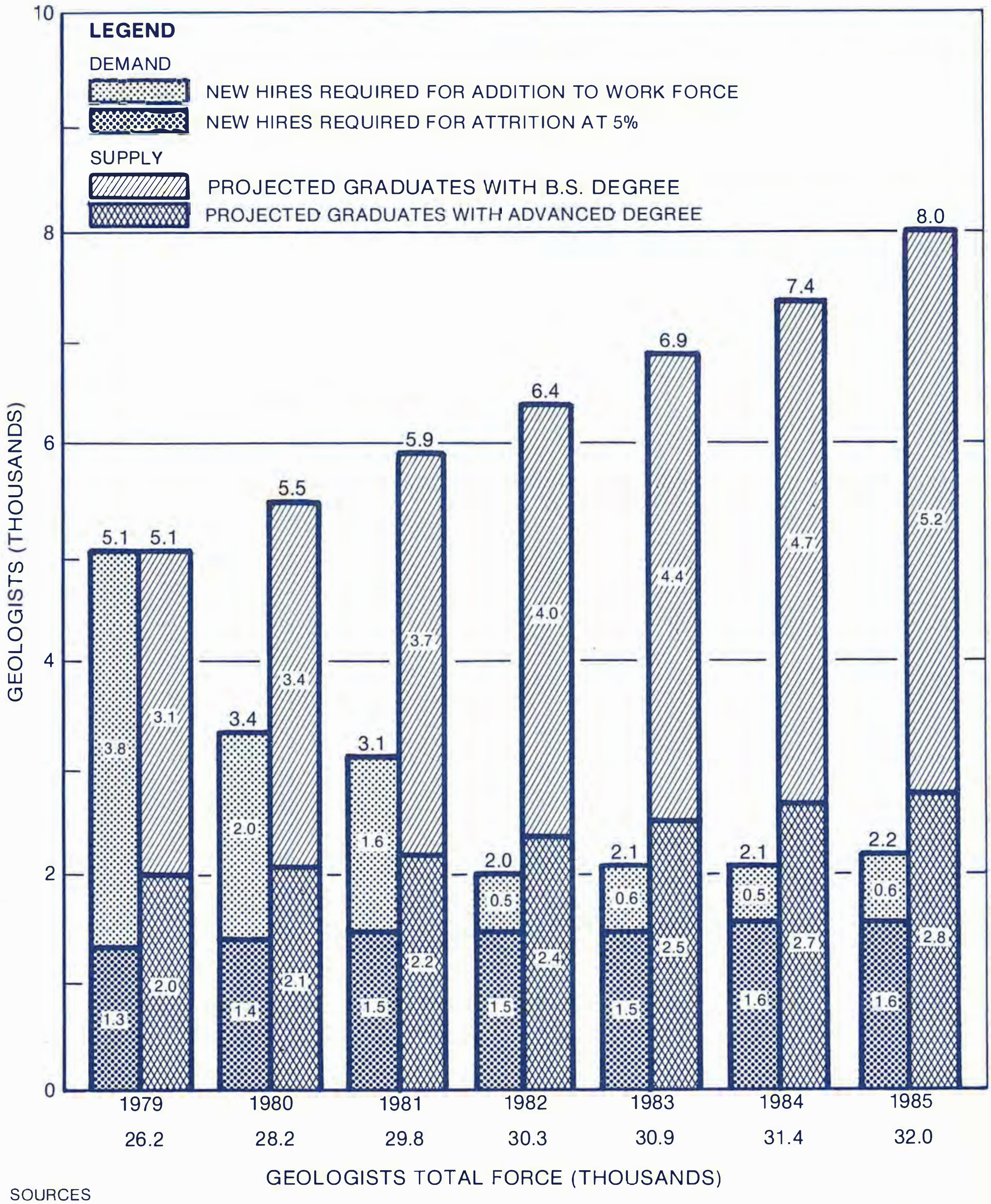
In 1979, salary offers for entry-level B.S. degree petroleum engineers averaged $1,818 monthly. This was the highest reported average salary for any discipline in the U.S. graduating class of 1979. The total number of graduating B.S./M.S. petroleum engineers entering the U.S. job market is projected to increase 70 percent, from 539 in 1978 to 917 in 1981, which compares with 306 in 1974. Table 33 indicates that companies should have increased success in meeting their hiring targets for petroleum engineers during the 1979-1981 period, and there may be a surplus of job seekers by 1982, followed by a reduced supply in 1983.

The high demand for petroleum engineers is further reflected in the rapidly growing practice of hiring off campus from a mobile pool of engineering personnel. The extremely high percentage of off-campus hiring by independents indicates their need for immediate performance of a new hire without the delays for training and experience. The SPE report showed that, in 1978, 17 percent of new hires by the responding major oil companies were from off campus, as were 27 percent hired by service and drilling companies, and 92 percent by independents.

The historical cyclic demand for engineers in drilling and production activities is of serious concern to educational institutions because of its disruptive effects on faculty and facility requirements, on funding, and potentially on the future quality of the education of petroleum engineers. High starting salaries for B.S. graduates have reduced the number of students entering graduate programs and, consequently, the reservoir of qualified candidates for faculty positions.

Continuing education of engineers, through in-house schools and programs offered by universities and outside consulting groups, is vital in order for the industry to maintain the competence and level of performance required in this complex and varied business.

In summary, the rapid increase in demand for engineers in drilling and production operations, which may have peaked in 1979, resulted in a shortage of petroleum engineering graduates.



SOURCES

Total Force based on 1978 estimate of 22,400 (See Appendix J, table J-5), and on growth projected on basis of survey of 48 companies (See Appendix J, table J-6).

Attrition rate not developed by survey. Estimate of 5 percent assumed reasonable.

Additions are net change in total force. Current vs. prior year.

Projected graduate based on survey of 30 schools (See Appendix J, tables J-10 and J-11). Assumes 30 percent of all enrolled students and 40 percent of advanced degree candidates graduate yearly.

NOTE: Surplus of graduates in excess of geologist demand would be available to meet industry needs for geophysicists and other employment.

Figure 22. Petroleum Geologists — Oil and Gas Companies
Estimated Supply vs. Estimated Demand, 1979-1985.

TABLE 31

YEAR-END NUMBER OF ENGINEERS EMPLOYED IN DRILLING AND PRODUCTION BY COMPANIES RESPONDING TO SURVEY

	Historical		High Level Projected		
	1974	1978	1979	1981	1983
Majors	5,157	6,790	7,429	7,810	8,038
Independents	288	525	584	688	775
Gas Companies	72	103	107	118	131
Service Companies	1,239	1,982	2,303	2,736	3,393

TABLE 32

HIRING OF ON-CAMPUS B.S./M.S. ENGINEERS BY RESPONDING COMPANIES

	Historical		High Level Projected		
	1974	1978	1979	1981	1983
All Disciplines					
Desired	826	1,379	1,504	1,415	1,537
Hired	763	1,370			
Petroleum Engineers					
Desired	372	579	599	558	577
Hired	232	385			

TABLE 33

HIGH LEVEL DEMAND AND PROJECTED AVAILABLE B.S./M.S. PETROLEUM ENGINEER GRADUATES OF RESPONDING UNIVERSITIES

	U.S. Job Entries	High Level Projected Number Desired				
	1978	1979	1980	1981	1982	1983
Demand						
Total Oil & Gas	494	902	833	863	866	914
Government Agencies	4					
Others	13					
Total	**511**					
Supply						
Available to U.S. Job Entry	539	789	852	917	956	866
Supply/Demand Ratio		0.87	1.02	1.06	1.10	0.95

The excess demand was met by hiring graduates of other disciplines on and off campus. The growth in petroleum engineering school enrollments is expected to produce graduates equalling or exceeding the demand during the 1981-1983 period. The two greatest concerns of petroleum engineering schools is that present growth rates will produce a significant surplus of B.S. graduates and that insufficient enrollment in graduate programs will result in a shortage of qualified faculty in the next decade.

Further data, methodology, and descriptive material relating to professional manpower are included in Appendix J.

Professional Education Institutions

Employers are almost entirely dependent on professional schools to ensure an adequate supply of qualified geophysicists, geologists, and engineers. However, the demand for professionals will be met by increased enrollments in these critical disciplines.

Industry demand for these graduates is highly cyclical, in large measure because of government regulation of exploration and production. This feast/famine demand cycle imposes serious problems on the universities and on young people in selecting a career. This could be mitigated by government policies that reduce uncertainties and facilitate more reliable oil company forecasts, and by the longer range hiring programs of the major employers.

Educational institutions report that they will need more funds if they are to expand their output of petroleum-related science and engineering graduates. Today, administrators have problems obtaining funds for expansion of capacity because of the cyclic demand for graduates. Also, engineering research, which makes possible graduate programs, receives little support from the federal government because school semester schedules restrict their ability to compete for research contracts. A possible solution would be action by the Department of Energy to support education through block grants to engineering schools, similar to those offered by the Defense Department which over several years helped build laboratory facilities and support faculty and graduate students in advanced degree programs deemed vital to the nation's welfare and security.

Continuing education, essential to the maintenance of engineering competence, includes keeping up to date on new engineering knowledge, maintaining technical competence, introducing industrial applications, switching disciplines, and working on advanced degree programs, interdisciplinary exchange, and administrative skills. To meet this need, oil and gas companies conduct in-house training programs to promote early competence in specialized fields such as reservoir, drilling, production, and gas engineering. Similar short courses are offered by several universities and a growing number of commercial programs by independent consultants. Also, the Society of Petroleum Engineers is active in the field with technical seminars, workshops, and video tape training programs.

Technicians and Skilled Workers

Drilling Companies

At mid-year 1979, the active drilling rig count was down 11 percent from mid-year 1978. However, the upward trend in activity experienced in the prior six-year period is expected to resume by year end, but at a slower rate of growth (Table 29). In view of the ability of the industry to man rigs during the heavy growth period 1973-1979, the manpower requirements for the slower growth in the next 10 years are not viewed as a likely constraining factor.

Well Servicing and Supply Companies

During the period 1973-1979, growth in drilling activity was matched by other oilfield service and supply organizations, demonstrating the ability of the industry in general to man as well as furnish equipment and supplies in response to the accelerated demand in that period. Regardless of that fact, however, service companies almost unanimously reported that their most critical potential limiting factor for the 1979-1990 period will be manpower availabiity. Companies are spending much time in training personnel, especially on-site operators and technicians, but high turnover rates are being experienced. This is reportedly due to a lessening overall desire to pursue careers which involve 24-hour callout status and working under harsh weather conditions. Thus, their top priority is to attract and train operators, technicians, mechanics, and field supervisors. In fact, the specialty tools industry plans growth in trainee level personnel of 67 percent annually over the 1979-1981 term and 15 percent per year over the 1981-1990 time frame.

The cementing and stimulation industry has identified a current manpower shortage of about two percent. With increased emphasis on training, however, the deficit should be erased by 1981 given adequate trainee material. Making up even a two percent deficit is an ambitious goal, considering that their total manpower needs are projected to grow at 10 percent annually from 1979-1981.

Geophysical Services

Trained technicians who are required to perform and support field data collection operations for the geophysical services industry are divided into three categories:

- Electronic technicians who operate and maintain the recording equipment, marine navigation, and other electronic equipment
- Surveyors who locate and map geophysical recording positions
- Mechanics and shot hole drillers who operate and maintain the mechanical, automotive, and seismic source machinery.

It was concluded that the industry's training plans for technicians are sufficient to meet maximum capacity growth. Adequate pay scales will attract the necessary surveyors, mechanics, and drillers.

Marine Services

The present supply of skilled offshore marine service personnel is adequate. It is, however, a potential constraint to rapid growth of the fleet, particularly since there is increasing pressure by the U.S. Coast Guard to require that vessels conform to American Bureau of Shipping class, thus requiring licensing of personnel. The licensed grades include Masters, Mates, Able Seamen, and Engineers. Time in service required by federal regulation to secure papers and high turnover rates contribute to the potential shortage. Industry training programs are expected to relieve the shortage but some relief of regulatory requirements could be necessary to avoid personnel constraints in a maximum expansion program.

Conclusions

Manpower for exploration, drilling, production, well servicing, and equipment manufacture will be adequate to support maximum projected activity levels for the study periods 1979-1981 and beyond to 1990.

Professional Personnel

Expanded activities under the most favorable projected business climate would tighten the supply of professional personnel, but this should not restrict oil and gas companies in seeking and developing investment opportunities. The demand for professionals will be met by increased enrollment, graduation, and subsequent employment of students in the critical disciplines of geophysics, geology, and petroleum engineering.

At the same time, because of high starting salary offers for B.S. graduates and insufficient funds for faculty and student support, enrollments are declining in the graduate programs of some engineering schools (particularly in petroleum engineering). If not reversed, this trend could erode the quality of engineering education and eventually lead to manpower constraints in terms of quality and quantity. This is a potential deficiency that cannot be readily overcome after graduates leave school. Rather, the solution would appear to be through the cooperation and support of the universities in a variety of ways by those who need to employ the graduate professionals.

Technicians and Skilled Workers

Some segments of the industry, particularly well servicing, are experiencing pressures from tight manpower supply and turnover. However, they have demonstrated the ability to meet sharp growth in demand in past years and are now intensifying training to meet current and projected needs. Therefore, no serious shortage is foreseen in non-professional manpower that would constrain expanded activity during the study period.

APPENDICES

APPENDIX A

Request Letter

Department of Energy
Washington, D.C. 20585

June 20, 1978

Dear Mr. Chandler:

An important goal of the President's energy initiatives is to increase the finding and development of the Nation's oil and gas resources. As the pace of exploration and production increases, constraints may appear from shortages of critical materials and trained personnel.

In the past, the National Petroleum Council has provided the Department of the Interior with several studies of materials and manpower requirements of the petroleum industry. The most recent study was completed in 1974 and dealt with the outlook through 1976. At this time, it would be appropriate for the Council to update that report and expand it where necessary.

I, therefore request, as an early and important part of the National Petroleum Council's new relationship with the Department of Energy, a comprehensive study of the materials and manpower requirements for oil and gas exploration and development. This study should focus on the period 1979-1981, but should also address the longer term situation. Particular attention should be paid to identifying areas of potential shortages in critical materials and manpower and methods of preventing such shortages. In addition, the impact of Federal, State and local laws and regulations should be explained and any appropriate recommendations for changes should be made.

For the purpose of this study, I will designate the Deputy Assistant Secretary for Policy and Evaluation to represent me and to provide the necessary coordination between the Department of Energy and the National Petroleum Council.

Sincerely,

James R. Schlesinger

James R. Schlesinger
Secretary

Mr. Collis P. Chandler, Jr.
Chairman
National Petroleum Council
1625 K Street, N.W.
Washington, D.C. 20006

APPENDIX B
Council and Committee Rosters

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Executive Committee
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College of Law
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Chairman of
Executive Committee
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Chairman of the Board
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APPENDIX C

Oil and Gas Exploration and Production Industry Descriptions

Oil and Gas Exploration and Production Industry Descriptions

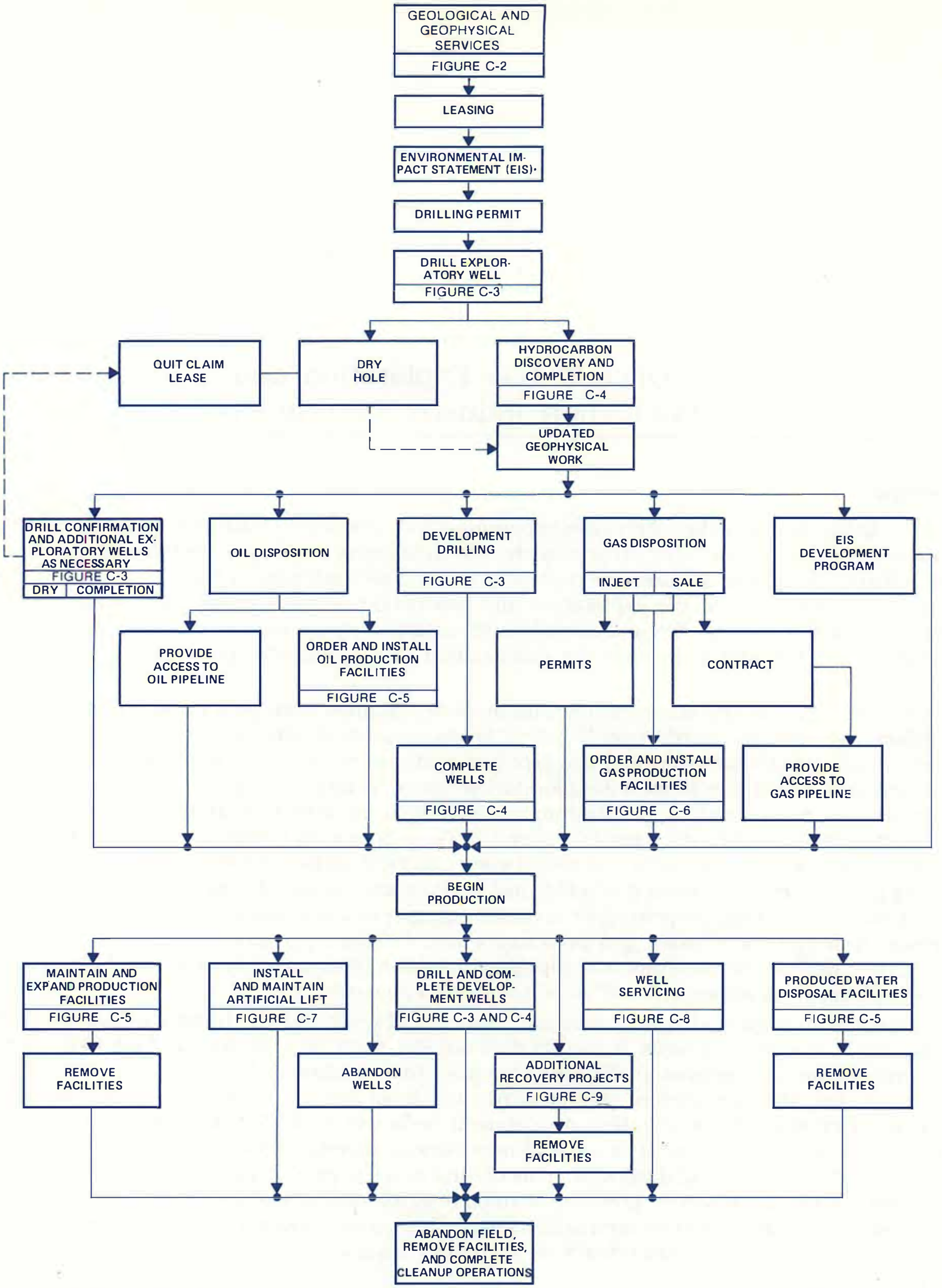
Overview

The many facets of the oil and gas exploration and production business are interrelated and interdependent and do not function separately. The industry is made up of thousands of producers, manufacturers, suppliers, and service contractors. The flow diagrams in Figures C-1 through C-9 illustrate the complexity of the exploration and production segment of the oil and gas industry. These show the flow of activities and the principal materials, equipment, and services required from the time exploration starts through the development of a commercial petroleum deposit to field abandonment.

Prior to starting any activities, permits must be obtained from land owners and local, state, and federal agencies as appropriate. If federal lands, onshore or offshore, are involved, a detailed description of planned activities and the expected environmental impact must be presented to the permitting agency with the proposed exploratory program. Before issuing a permit, the agency must prepare an Environmental Impact Statement (EIS) and circulate it to interested parties in compliance with the Federal Environmental Policy Act. The EIS process is very time consuming and can be delayed for extended periods by interested state and local authorities and by court action of any opposing party. After activities begin, additional permits are required before each significant action is taken, such as drilling, deepening, or abandoning each well, and obtaining a connection for selling production and for disposing of produced water. Offshore, permits are required for platform construction, production facilities, and pipelines. All discharges into U.S. waters and air emissions require permits from either or both state and federal agencies.

Exploration begins with geological and geophysical work and continues through the drilling and logging of one or more wells. It usually does not stop with the completion of a single discovery well. Confirmation and extension wells are necessary to determine if the reservoir is of commercial quality and size. After a sufficient volume of producible oil and/or gas has been indicated to exist, production facilities will be installed, development wells will be drilled, and production initiated. During the production phase, it is usually necessary to employ servicing equipment to re-enter producing wells to do remedial work, such as control of water production or formation sand incursion. When the natural reservoir pressure of an oil reservoir declines as oil is extracted and a well no longer flows, artificial lift devices are usually installed, such as beam and rod supported subsurface pumps or gas lift facilities. Compressors are frequently installed to increase the rate and extend the producing life of gas wells.

Throughout the life of the field to final abandonment, well and reservoir performance are studied, and remedial, stimulation, and recompletion work is performed on wells by servicing companies to maintain production. Occasionally, old wells must be deepened or supplemental wells drilled to maintain production from oilfields. A constant effort is maintained to save and sell or inject all produced natural gas. Water produced with the oil is treated and then disposed of by injection into the ground or discharged into surface waters when legally and environmentally acceptable.



*"CHART" DESIGNATIONS REFER TO ADDITIONAL FIGURES IN APPENDIX C.
† COMPLY WITH SECTION 102(2)(C) OF NATIONAL ENVIRONMENTAL POLICY ACT IF FEDERAL LEASE REQUIRES PREPARATION AND APPROVAL OF ENVIRONMENTAL IMPACT STATEMENT (EIS).

NOTES: (1) MANPOWER REQUIREMENTS WHILE NOT DETAILED IN THE ATTACHED CHARTS, ARE SUBSTANTIAL IN ALL PHASES OF THE PETROLEUM INDUSTRY. ALL TYPES ARE REQUIRED INCLUDING TECHNICAL, SKILLED AND COMMON LABOR.
(2) NOT SHOWN ARE REQUIREMENTS FOR PERMITS AND APPROVALS BY NUMEROUS FEDERAL, STATE AND LOCAL AGENCIES THROUGHOUT THE LIFE OF THE FIELD.

Figure C-1. Simplified Flow Diagram Showing Operations Necessary for Discovery, Production, and Abandonment of an Oilfield.

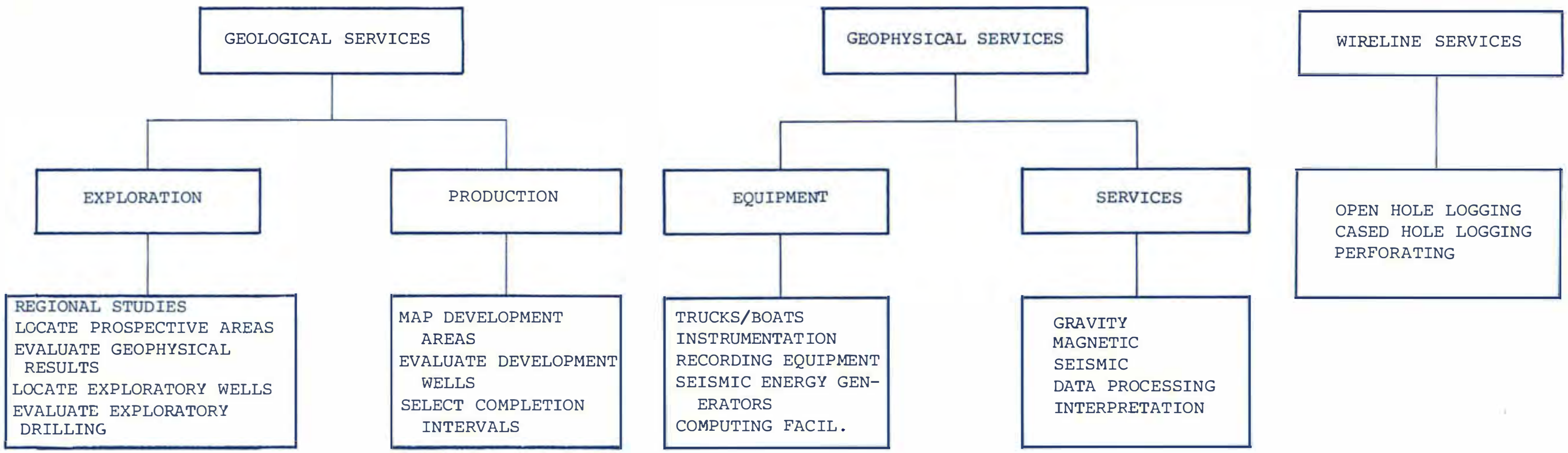


Figure C-2. Geological and Geophysical Services.

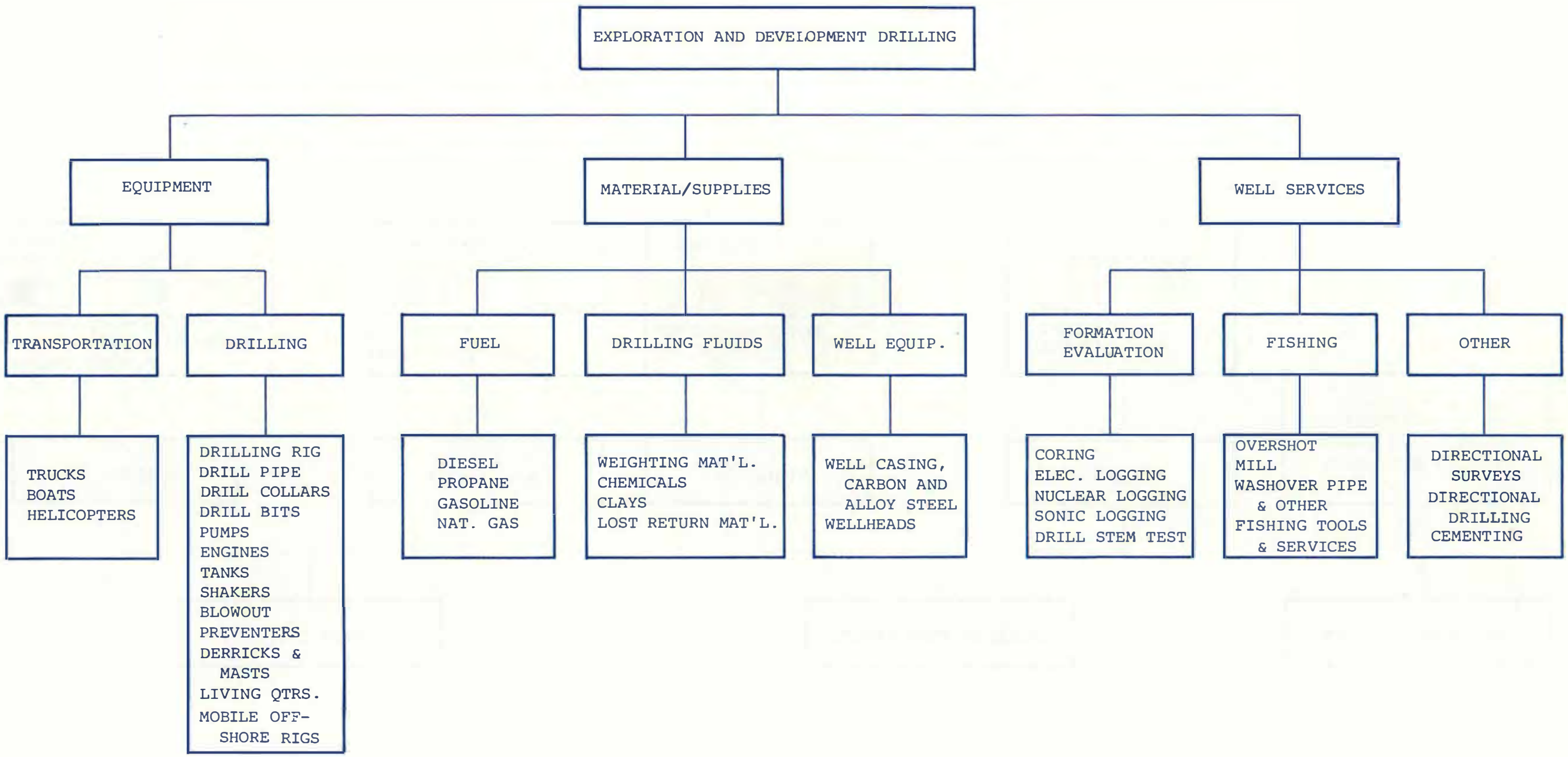


Figure C-3. Exploration and Development Drilling.

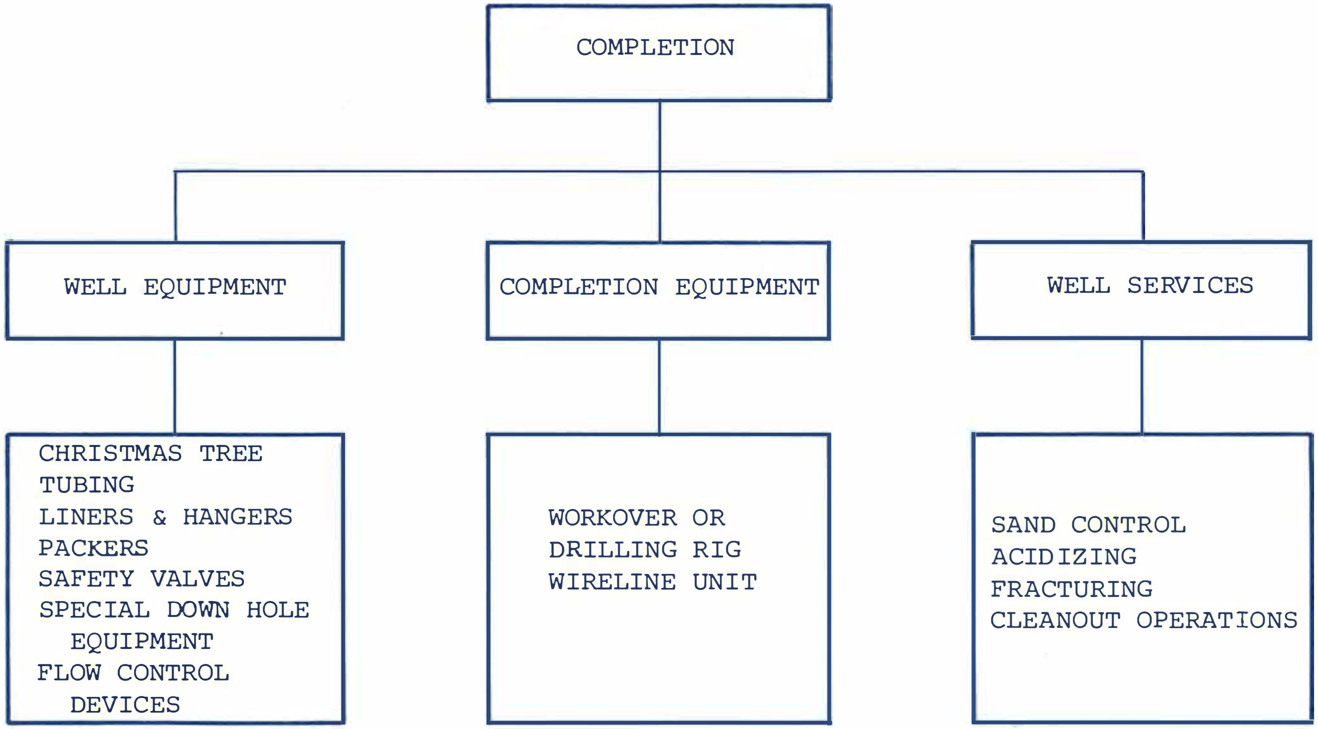


Figure C-4. Completion.

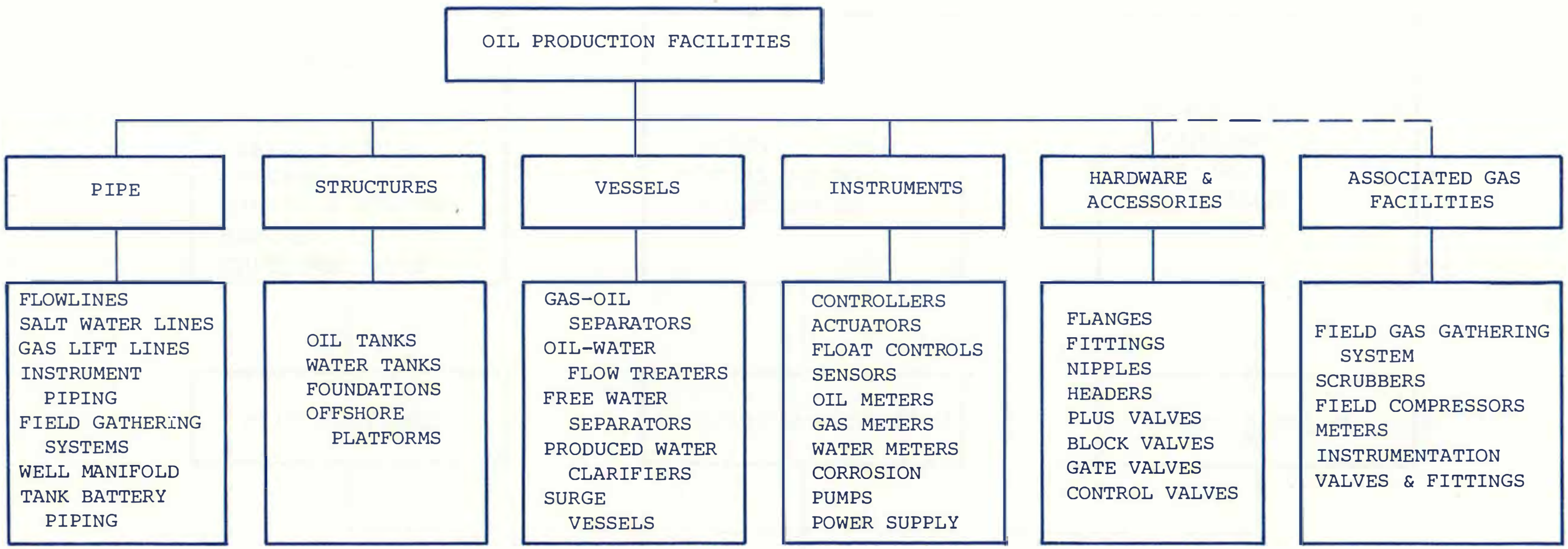


Figure C-5. Oil Production Facilities.

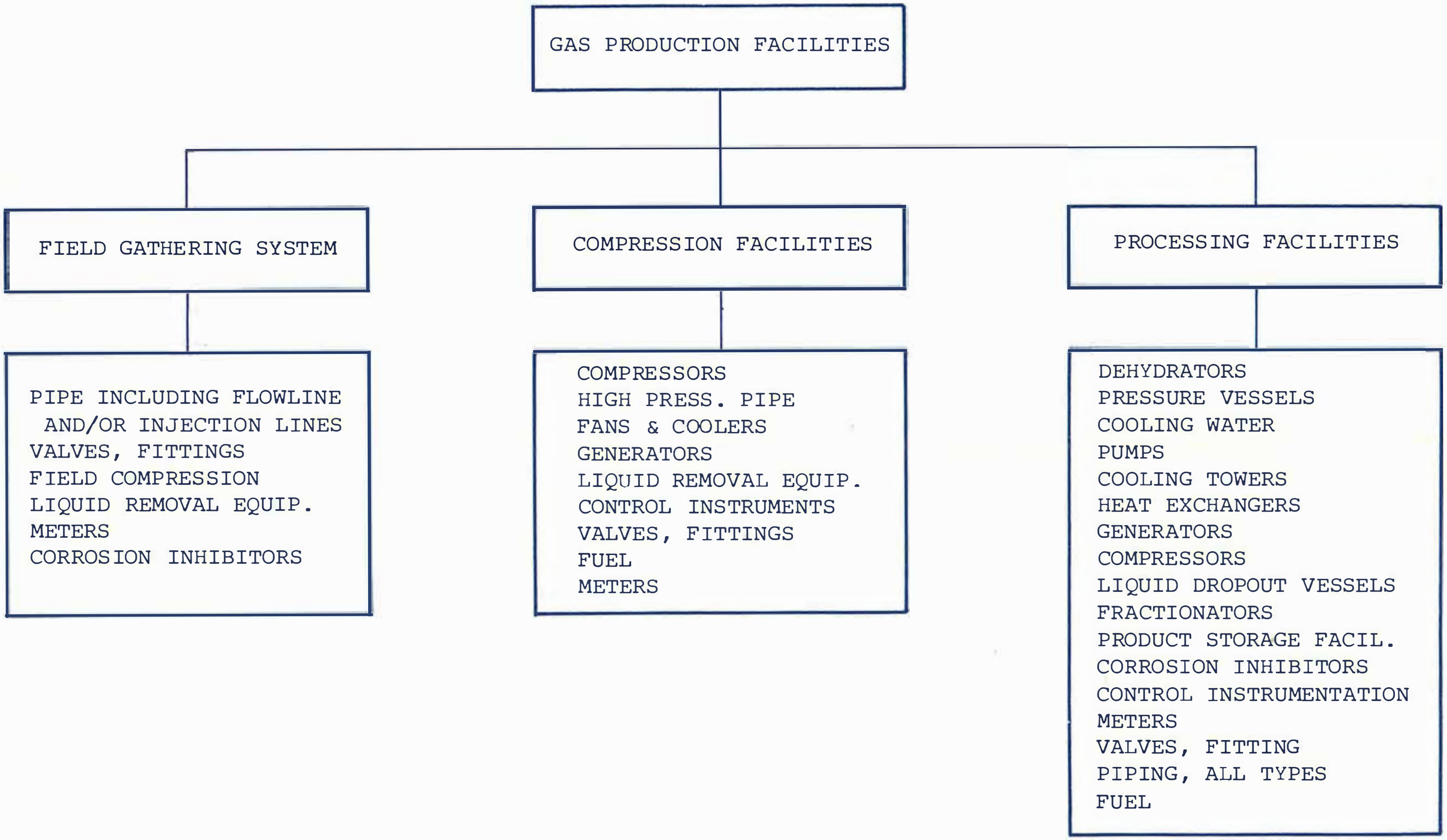


Figure C-6. Gas Production Facilities.

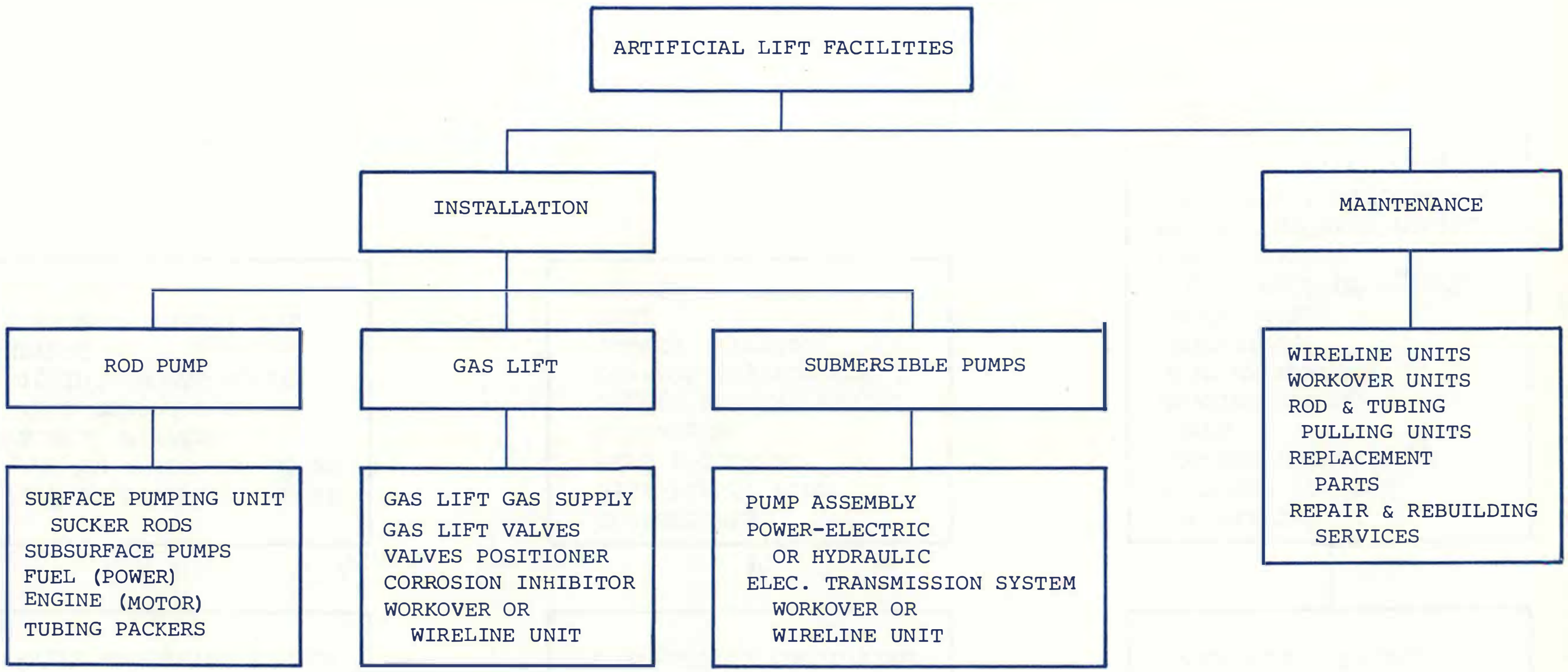


Figure C-7. Artificial Lift Facilities.

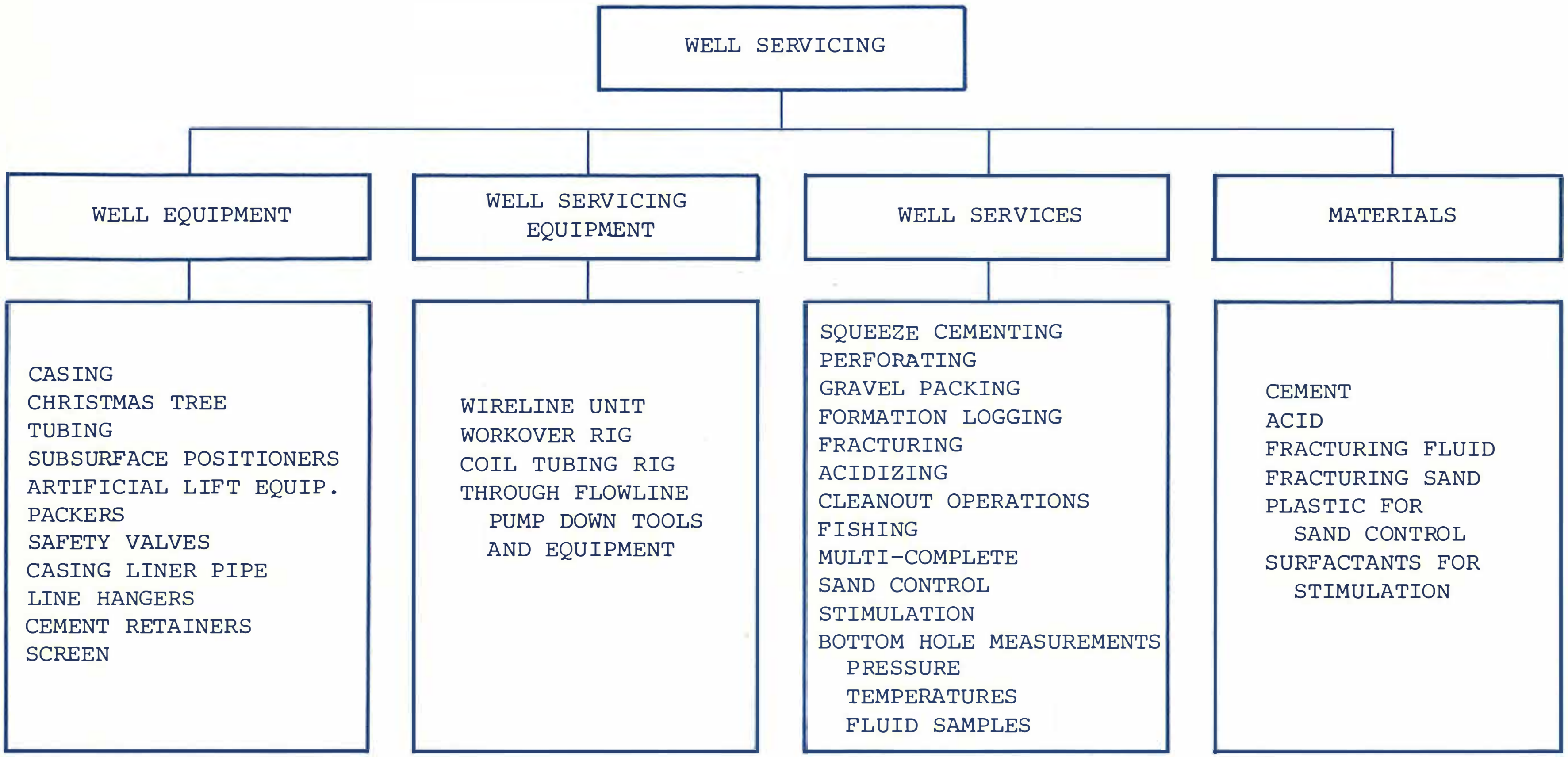


Figure C-8. Well Servicing.

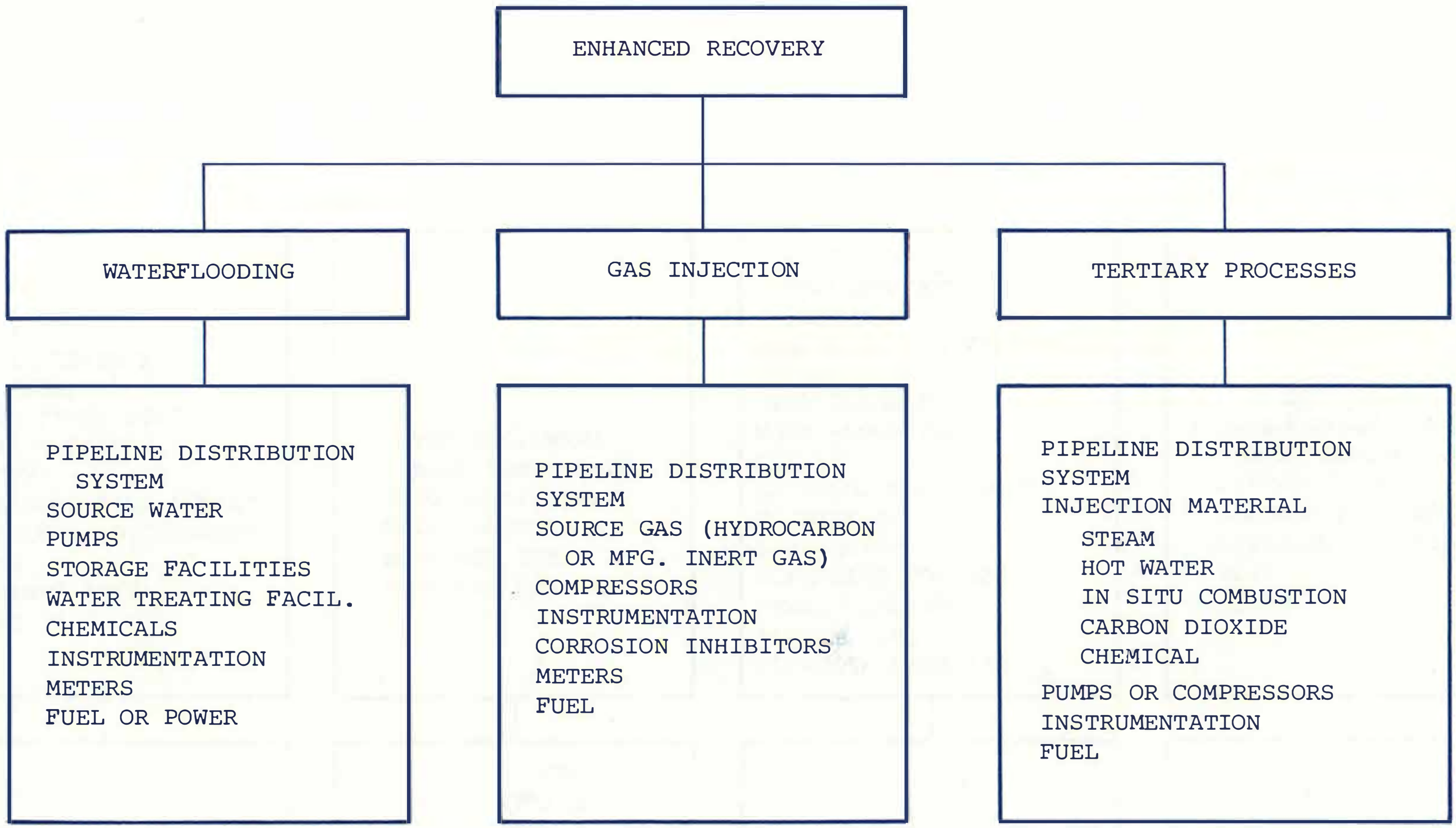


Figure C-9. Enhanced Recovery.

Most gas produced with oil or from gas wells is marketed, although some is injected for additional recovery of oil. A large part of the gas produced with oil and from gas wells contains enough heavy hydrocarbons (propane, butane, and natural gasoline) to economically justify processing for extraction of natural gas liquids. Other produced gas may contain almost all light hydrocarbons (methane and ethane) and is marketed without liquids extraction.

As a field matures in productive life, reservoir engineering studies show what can be expected in ultimate recovery and if the field is susceptible to yielding additional oil by fluid injection (water is the most commonly injected fluid). If the prospects are good, pressure maintenance and secondary recovery projects will be started, usually after reservoir ownership has been unitized to protect the correlative rights of both operators and royalty owners. Nearly all such projects require unitization, because fluid injection into a reservoir will normally move oil or gas across ownership lines. Some oil reservoirs can be revived for a third productive life (tertiary recovery) by injection of steam or chemicals (carbon dioxide, polymers, and surfactants).

During secondary or tertiary recovery operations, the day-by-day business of producing operations must be continued. Remedial well work never stops: artificial lift equipment must be serviced, surface facilities maintained, and replacement production and injection wells drilled. As wells become uneconomical to produce, they must be plugged with cement, salvageable casing pulled, surface equipment removed, and the surface area cleaned up in a manner acceptable to the owner of the surface rights and to the regulatory agencies.

For the purposes of this study, the material, equipment, and services used in these operations were subdivided into five categories: geological and geophysical services; drilling equipment; tubular steel; production equipment; and well servicing.

Geological and Geophysical Services

Geological and geophysical services (Figure C-2) are defined as those services provided by:

- The professional oil and gas geologist community
- The geophysical services industry that provides, processes, and interprets surface geophysical measurements used in the exploration and development of oil and gas
- The wireline services that provide physical measurements and mechanical services in wells.

Geological Services

Geologists study the structure, composition, and history of the earth's crust. They determine the types and disposition of rocks on and beneath the earth's surface. In the search for petroleum, the geologist usually looks for three essentials. First, the source beds of shales or limestones which originally contained an abundance of organic remains; next, the porous sandstones or limestones which later became the reservoir beds of migrating oil and gas; and, finally, the trap that sealed off the reservoir beds and held the hydrocarbons in place. Geological services are further described in Appendix J.

Geophysical Services

Geophysical measurements taken at the surface provide the major clues for locating potential subsurface reservoirs which may contain hydrocarbons. The measurement of changes in the earth's magnetic and gravity fields provides data from which an experienced interpreter may broadly define potentially prospective areas or features. However, the major geophysical tool used in oil and gas exploration is seismic reflection. In this method, a physical pulse or vibration is created at or near the surface, producing a wavefront of sonic energy which travels through the subsurface and is partially reflected back to the surface each time the wavefront encounters a discontinuity such as the boundary between two rock layers. This reflected energy is picked up at the surface by very sensitive microphones called seismometers, or geophones, which convert the sonic energy into electrical energy that is then amplified to produce usable signals. The seismograph records these signals as a function of elapsed time, with time zero as the instant the pulse was created. A geophysicist then measures the sonic wave travel time from the surface to one or more reflecting discontinuities within the subsurface and back to the surface again. Having determined the two-way travel time, the geophysicist can calculate the depth of the discontinuity after determining the velocity at which the sonic wave travels. By making measurements at many points, the geophysicist determines the average velocity of sound through the subsurface rocks and thus the depth to a particular discontinuity at a number of locations. From these data a contour map of the subsurface is produced, from which a geologist determines the most likely locations within which hydrocarbons may be trapped.

The above is an oversimplified description of a complex process. The pulse at the surface has classically been created by firing a small dynamite charge in a shallow borehole, and this type of source still accounts for nearly 70 percent of all seismic work. Modern technology has produced other sources which are either more economical or have technical advantages: compressed air charges, which are used almost exclusively in marine seismic surveys; vibratory sources, which, because of economics, environmental considerations, and technical advantage, are the fastest growing dynamite replacements on land; and a variety of other sources, such as weight-drop, gas exploders, and compressed air guns, that are used for special applications.

Because the energy created by these sources is very low, and the reflected energy received back at the surface is even lower, the seismologist's chief problem is to recognize these reflection signals in the background of seismic noise which is always present. Modern methods used to solve this problem include:

- Digital recording of data
- Computer processing to extract the signal from the noise
- Correction for earth-induced errors
- Extraction from the signal of meaningful information about the character of the rock formation and, in the best of circumstances, significant information about the hydrocarbon content of the reservoir rocks.

Because of the sophisticated technological developments which are proceeding at a rapid pace, the seismic survey, which historically has been an exploration tool, is being used more in field development. It is anticipated that as technology improves, the seismic survey will be used even more broadly in reservoir engineering analysis.

Seismic data collection crews in the United States are operated by about 50 geophysical contracting companies and 10 oil companies. Contractors provide about 90 percent of the crews. Computer processing of the data is split almost equally between contractors and in-house oil company data processing centers. Geophysical interpreters, who are sometimes difficult to separate from geologists, are mostly employed directly by the oil companies, although a significant fraction is supplied by consultants and contractors.

The five or six largest contractors from the United States, along with one French contractor and one German contractor, supply a large majority of the international seismic crews. Most of the rest are provided by a few government oil companies whose crews operate within their own countries.

Equipment used in supplying geophysical services includes specialized electronic recording instruments for recording seismic data, magnetometers, gravimeters, and other specialized recording and measuring devices. Computers, ranging from small microprocessors used as control devices to giant super-computers for sophisticated data processing, are used extensively. For field operations, all kinds of automotive and truck equipment are used, including customized or special purpose vehicles to transport equipment through swamps, deserts, and frozen Arctic tundra. Truck-mounted drilling equipment, capable of drilling holes 100 feet to 1,000 feet deep, is utilized. Other, more specialized, seismic energy generators, such as large vibrators, air compressors, weight drop units, etc., are frequently mounted on specially designed vehicles. At sea, ships ranging in length from 150 to over 250 feet are used.

Wireline Services

Well loggers and perforators who make up the wireline services industry operate as contractors to producers in finding and producing oil and gas. In a minor way, they also furnish services to the coal and uranium markets.

The function of this specialized industry is to provide mobile service units at the well site with instrumentation and personnel to lower tool strings into the well, record data, and perform mechanical services controlled and recorded at the surface. The industry provides a range of services that are critical to the successful evaluation and completion of almost every well drilled for oil and gas in the United States. During the drilling phase, there are generally one or more descents made into the well bore with sensitive well logging instruments to record the geological and reservoir information by measuring:

- Resistivities
- Natural radioactivity
- Natural electrical potential (SP)
- Induced radioactivity
  - Neutron-neutron
  - Thermal decay time (neutron)
  - Compton scatter
- Sonic energy
- Electromagnetic propagation.

Each of these physical measurements can be used to calculate or estimate the properties of subsurface rocks traversed by the well bore and/or the properties of fluids contained within the rock formations. The wireline, which lowers the instruments into the hole, measures the depth of the instrument. Given an accurate measurement of depth and the means to determine rock properties and fluid content, the geologist or reservoir engineer can interpret the location and vertical extent of gas, oil, and water in the well bore, and thus develop a plan for testing, completion, and production of the well. With similar data from several wells in a field, a reservoir engineer can estimate the extent of the subsurface reservoir and its probable producing characteristics. This information is used to develop a plan to maximize petroleum production from the reservoir.

The measurements are related to the physical properties of the rock, which are, in turn, related to the reservoir parameters. Thus, the logs recorded in the newly drilled well bore (termed open hole) constitute the information base for most geological and reservoir evaluation. Since these measurements can be made only at intervals as the well is drilled, the well logging service units must be at the drill site at the times required. On land, the units are mobile trucks and serve the wells individually on a time and call basis. On the offshore units, the well logging unit is an integral part of the drilling rig (although it is detachable and replaceable). The well logging industry is thus on a 24-hour continuous service basis to be available when the well reaches a depth of interest. With the 24-hour service requirement comes the need for an adequate number of well logging units to be available, so the drilling rig does not have to suspend operations due to the non-availability of a unit. The well logging industry is encouraged to keep enough units available by being competitive. If one company cannot provide service, another one will. This open hole portion of the well logging business is therefore intimately tied to active drilling rigs, as the newly drilled well bore constitutes the basic market.

Complementary to this use of the open hole logging services industry are the cased hole services which also use similar (but not identical) equipment. Again, the well logging cable is used to lower instruments into the cased (metal pipe) well. These instruments, by radioactivity and temperature measurements and mechanical flow meters, determine some of the rock characteristics, cement quality, mechanical condition, flow rates, and possible movement of fluid behind the casing. Mechanical services are performed, such as setting plugs and packers, and perforating the casing at appropriate depths. Since every new well must be completed, the demand for cased hole wireline services relates to the number of successful wells, cased for testing and production.

The same cased hole services are used with workover rigs whose function is to repair damaged wells or to recomplete the wells in alternate zones. Thus, demand for cased hole wireline services also relates to the well servicing activity.

Drilling Equipment

Drilling Rigs

A rotary drilling rig may be thought of as a portable factory designed to drill a hole to a particular geological formation and to wall the hole with steel pipe and cement, with the objective of exploring for and developing oil and gas fields. The requirement for portability places a limitation on rig design, both as to weight and as to the size of each component. Except for some specialized items such as pressure control systems, the same kind of drilling machinery is used offshore as on land. The rig support may be dry land, an inland submersible barge, an artificial island, a fixed structure, or a mobile offshore unit.

For the purposes of this industry description, equipment and materials for drilling are divided into eight categories: drilling rigs, mobile offshore rigs, drill pipe, tool joints, drill collars, drill bits, pressure control equipment, and drilling fluids.

The three main functions of all rotary drilling rigs are performed by the hoisting, circulating, and rotating systems. Figure C-10 shows the relationship of the major components which make up the rotary drilling rig. Equipment and materials used are listed in Figure C-3.

Hoisting System

The mast or derrick supports the hook by means of the traveling block, wireline, crown block, and drawworks. The drawworks is powered by prime movers, which are usually two to four engines. Most inland rig drives are diesel mechanical and some are gas engines. Diesel electric drives are common offshore.

During the drilling operation it is necessary to pull and rerun the drill pipe to change bits, to run casing, and if the well is successful, to run tubing. To perform these functions, elevators are suspended from the hook and are latched around the pipe below a coupling or drill pipe tool joint so that the pipestring may be hoisted.

Circulating System

When drilling is in progress, mud pumps and prime movers are used to circulate the drilling fluid from the mud tanks through the standpipe, rotary hose, swivel, kelly, drill pipe, and drill collars to the bit and upward through the annulus between the drill pipe and open hole and casing to the surface. The fluid flows out of the annulus above the blowout preventers, over the shale shaker to remove formation cuttings, and back into the mud tanks.

Rotating System

The rotary is the machine which gives a rotary rig its name. The rotary table, powered by prime movers, rotates the kelly through the kelly drive bushing, which rests in a square recess in the rotary. The kelly, a flat-sided, usually hexagonal hollow forging, 40 to 45 feet long, is suspended by the swivel and hoisting machinery during drilling operations. It is free to move vertically through the kelly drive bushing and serves to suspend and rotate the drill pipe. When drilling or circulating operations are suspended for the bit to be pulled or casing run, the swivel, kelly, and kelly drive bushing are removed. A device called slips is placed in the rotary recess around the pipe to suspend it when not being lifted by the elevators, as it is being run or pulled from the hole.

Mobile Offshore Rigs

Mobile offshore drilling rigs are used primarily in exploratory drilling. The type of mobile rig used is usually a function of water depth and combinations of sea states and weather. The four principal types of mobile rigs are: submersible, jack-up, drill ship, and semi-submersible.

Submersible

A submersible is a barge-like vessel supporting a drilling rig and its equipment. It is towed to its location and submerged to sit on the ocean floor, where it serves as a fixed platform. It typically operates in shallow (25 to 50 feet), calm waters. Submersible rigs were the forerunners of the present generation of mobile rigs, and their functions have been largely assumed by jack-up rigs. Many submersible barge rigs are used in shallow (6 to 10 feet) inland water operations.

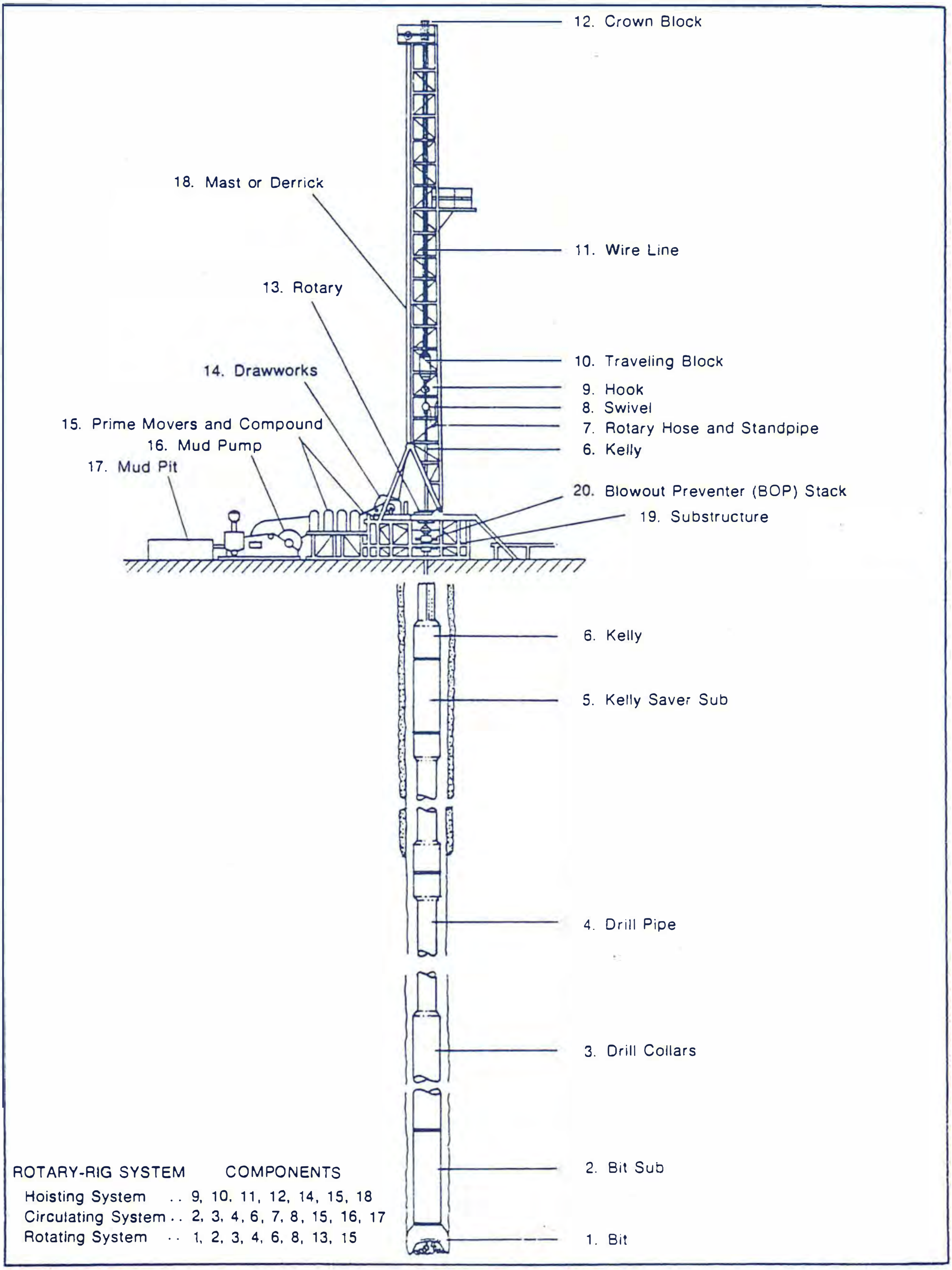


Figure C-10. Systems and Components for a Rotary Drilling Rig.

Jack-Up

Jack-up rigs have retractable legs which are lowered to the sea bed and enable the body (hull) of the platform to be raised to a safe distance from the sea's surface. Jack-ups can drill several wells in a single set-up, can withstand severe weather, and are generally the best mobile rigs available for water depths to 300 feet.

Drill Ship

A drill ship is a free-floating, ship-shaped vessel which is kept in position by multiple anchors or by dynamic positioning with propeller thrusters. Drill ships have a number of advantages, including proven deep water capability, ability to transport large loadings of drilling supplies, fast travel time to remote locations, and relatively low operating cost. The disadvantage of a drill ship is its limited capacity to operate in wind or wave conditions which produce excessive platform motion.

Semi-submersible

A semi-submersible platform is supported by a pontoon hull which is at the sea surface in the transport mode. When in the drilling mode, the hull is submerged below the wave troughs and the platform remains above the wave crests. Stability is maintained by cassion legs which connect the hull to the platform. The unit is anchored or dynamically positioned by means of computer-controlled propeller thruster motors. Major advantages of a semi-submersible are its deep water capability, platform stability, operating performance in severe weather, and good mobility.

Drill Pipe

Drill pipe is the steel tube used to transmit rotating force from the rotary, located on the derrick floor, to the drill bit on bottom of the hole. The rotating force and weight of the drill collars provide cutting power to the drill bit. Queued drill pipe rests on the derrick floor in stands, which are connected lengths of two or three joints. The drill pipe also serves as the conduit for the downhole circulating system. Throughout the drilling operation, drilling fluid is pumped downhole through the drill pipe and back up the annular space to the surface.

Drill pipe outside diameter (O.D.) ranges from 2-3/8 inches to 5-1/2 inches. The most common sizes are 4-1/2-inch and 5-inch O.D. API standard drill pipe is furnished in various sizes in the following lengths:

Range 1—18 to 22 feet (obsolete)
Range 2—27 to 30 feet
Range 3—38 to 45 feet

These lengths do not include the length of tool joint that is attached to each end. Drill pipe is made in two basic ways: seamless and welded. Almost all drill pipe used in oil and gas wells is made by the seamless process. API seamless steel drill pipe is offered in five grades of steel having a minimum yield strength range of 55,000 to 135,000 psi, and a minimum tensile strength range of 95,000 to 145,000 psi.

Drill pipe is usually owned by the drilling contractor, and is removed and taken to a new location when drilling is completed. Demand for drill pipe is generated by new drilling rig sales, both domestic and overseas, and by replacement of worn out strings.

Tool Joints

Tool joints are coarse threaded couplings of high strength abrasion-resistant steel, welded on the ends of each length of drill pipe for connection into a string. A tool joint unit consists of two parts: the pin and the box. The male section (the pin) is attached at one end of the length of drill pipe, and the female section (the box) is attached to the other end.

Tool joints are subjected to extreme stresses not encountered by casing or tubing. To meet the varied requirements, the API standard lists several joint designs, all of them weld-on connections to the drill pipe. Major tool joint manufacturers also offer proprietary shrink-on threaded connections, with their own particular thread designs. Tool joints are designed to resist wear from rotation in the hole, provide a thread that is easy to start, resist damage, and when made up will be leak tight. The connection to the drill pipe must avoid stress concentrations to minimize the possibility of fatigue failure.

Drill Collars

Drill collars are heavy, thick-walled tubes employed between the drill pipe and the bit in the drill string to improve bit performance. Standard drill collars are 30 feet long and are made from AISI-4145H chrome-moly heat-treated bars. The outside diameter is larger than a tool joint and may be close (within one inch) to the size of the bit diameter. Connections are coarse, stress relieved flush joint threads. That is, there is no shoulder at the connection, resulting in a smooth, constant diameter drill collar string. A string of drill collars—two or three in some areas, or ten times that many in others—has the following functions:

- To provide weight on the bit for drilling
- To hold the drill string in tension to avoid buckling
- To provide a pendulum effect, causing the bit to drill vertically when desired
- To stabilize the bit in order to drill a new hole aligned with the hole previously drilled, in the desired direction and angle when drilling directionally.

The diameter of the drill collars and amount of weight on the bit depends on the following factors:

- The diameter of the hole
- The bit type
- The tendency of the hole to deviate from the vertical, which varies with formations
- The buoyancy (specific gravity) of the drilling fluid.

Drill collar weight on the bit may be as low as a few thousand pounds in a small diameter hole when drilling soft formation, or more than 100,000 pounds when using a large bit in hard formation.

Drill Bits

A drill bit is the cutting or boring element below the drill collars on bottom of the drill string. A short wear sub is used to connect the bit to the drill collars to reduce wear on drill collar threads. Most bits used in rotary drilling are the roller-cone type, which have tapered steel devices called cones that are free to turn as the bit rotates. Typical roller-cone bits have three cones, although some have two and some four. Bit manufacturers either cut teeth in and hard face the cones or insert very hard tungsten carbide buttons into the cone surface.

The bit penetrates formation through the combined cutting, gouging, and grinding action of the rotation and weight on bottom, and the hydraulic action of fluid pumped down the drill pipe and out through holes in the bit. Jet bits have nozzles that direct a high-velocity stream or jet of drilling fluid to the sides and bottom of each cone, so that rock cuttings are swept out of the way as the bit drills.

Years of research have gone into bit design to ensure compatibility with the projected hole size, depth, and type formation. Bit suppliers maintain well record files and are able to recommend bit programs for wells almost anywhere in the world. Computer programs are available that can predict how much weight to carry on the bit, pumping pressure, rotary speed, and how long to drill before changing bits to result in minimum cost drilling.

Pressure Control Equipment

Pressure control equipment makes up the system designed to seal a drilling well at the surface of the hole, below the derrick floor, to prevent unwanted flow from the well, either through the annulus around the drill pipe or while the drill pipe is out of the hole.

The assembly at the top of the well and attached to the casing head, called the blowout preventer (BOP) stack, may consist of any of several combinations of annular and ram-type blowout preventers, controlled by a hydraulic operating system located at a safe distance from the well bore.

The two basic types of blowout preventers are annular type and ram type. The annular type, which is usually located on top of the BOP stack, closes radially. It can seal around any size pipe that can go through it, around the hexagonal kelly, or to a limited extent close the open hole. Ram-type blowout preventers seal around the pipe with preformed half-circle rubber blocks embedded in two steel rams or plungers mounted in the blowout preventer body on opposite sides of the hole. The rams must be sized to fit the drill pipe being used. Blank rams are fitted with straight parallel rubber blocks for use when the drill pipe is out of the hole.

Blowout preventers are made in pressure ratings compatible with wellhead pressure ratings and drilling requirements, and in a wide range of sizes.

As a safety device to prevent backflow through the drill pipe while drilling, a kelly valve is installed on all drilling rigs at the top of the kelly, immediately below the swivel, where it can be closed in an emergency. A back pressure valve equipped with tool joint threads is kept on the derrick floor during drilling operations so that it can be screwed into the drill pipe if the well starts to backflow while the kelly is disconnected. Some rigs also use a drop valve which can be pumped down the drill pipe to shut off flow at the bottom.

Hydraulic fluid for opening and closing blowout preventers is stored in a pressure accumulator located about 100 feet from the rig floor. Rugged, high-pressure lines carry the hydraulic fluid from the accumulator to the BOP stack, and when control valves on the rig floor are actuated by the driller, the fluid operates the preventers. The hydraulic fluid is under pressures ranging from 1,500 to 3,000 psi.

Drilling Fluids

Drilling fluids, commonly called muds, are complex blends of minerals chemically suspended in a water or oil base medium. Requirements for these fluids vary greatly in density and composition with well depth and geological conditions. Some of the functions of drilling fluids are to:

- Transmit hydraulic horsepower to the bit
- Enhance penetration through jet action
- Cool and lubricate the bit
- Remove cuttings from the bottom of the hole and transport them to the surface
- Lubricate the hole to reduce drill pipe rotational friction
- Control formation pressure by weight of the column of fluid
- Provide buoyancy support for part of the weight of the drill pipe and for the weight of casing strings while they are being run
- Wall the hole with an impermeable cake
- Hold cuttings and weighting materials in suspension when circulation is interrupted
- Release cuttings at the surface
- Minimize adverse affects of fluid invasion of formations penetrated
- Ensure maximum information about the formation.

To accomplish these many functions under extreme variations in formation pressure, temperature, and competence requires drilling fluids programs designed for local conditions and close surveillance by trained personnel. To produce the desired fluids, the most common materials added to the natural drilling fluid generated by drilling with water are:

- Attapulgite clay to build up fluid volume
- Barite to add weight
- Bentonite to add viscosity (thickener)
- Lignosulfonates to lower viscosity (thinner)
- Starch, calcium chloride, soda ash, and caustic soda to control fluid loss to the formation
- Bactericides to prevent deterioration of starch muds.

Tubular Steel

This includes all tubular steel used by the oil and gas industry for drill pipe (Figure C-10), casing and tubing (Figure C-11), and line pipe required to convey gas and oil from successful wells to production facilities, storage tanks, and/or transmission pipelines (Figures C-12 and C-13). Casing, tubing, and drill pipe are referred to by the trade as oil country tubular goods (OCTG).

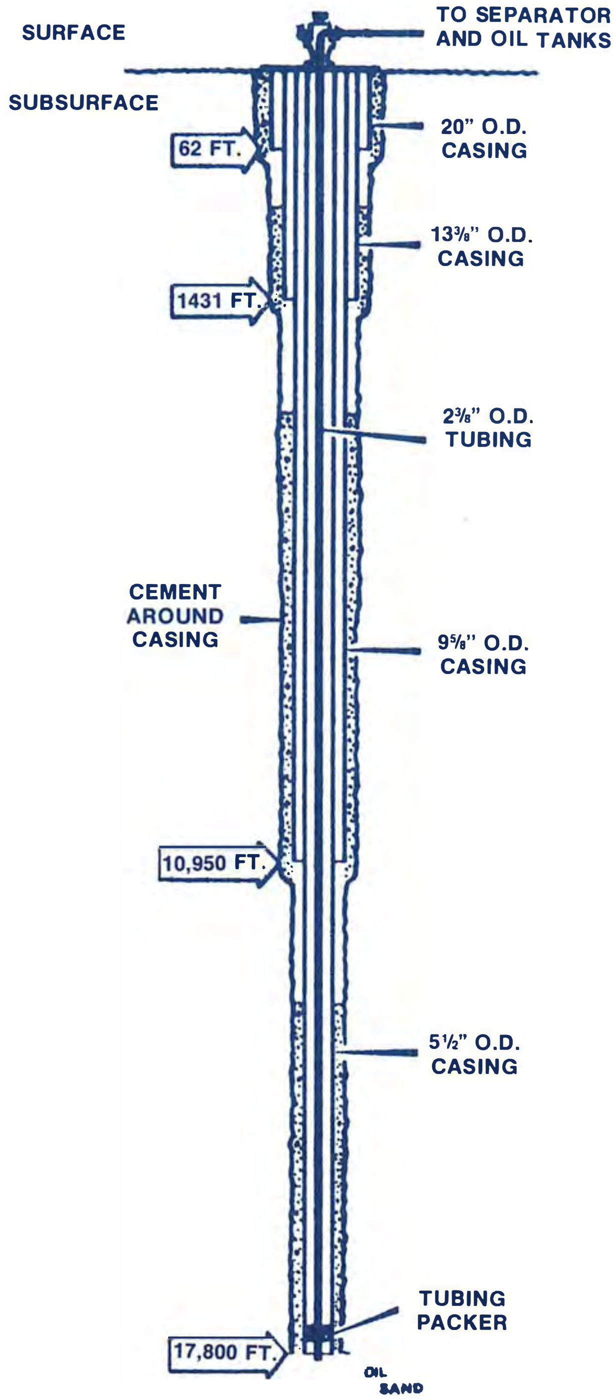


Figure C-11. Typical Oilfield Usage of Casing and Tubing in Deep Producing Wells.

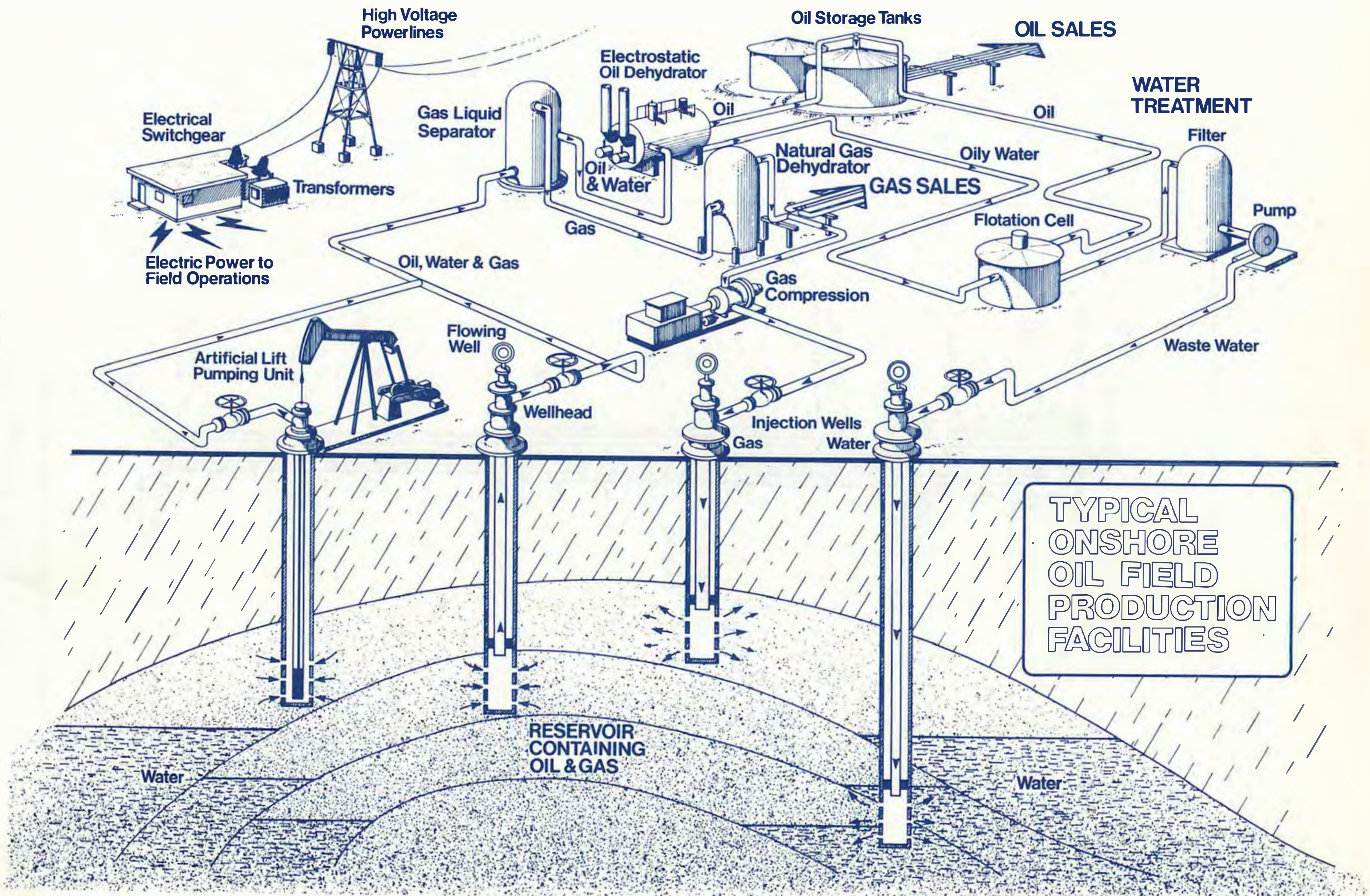

High Voltage Powerlines
Oil Storage Tanks
OIL SALES
Electrostatic Oil Dehydrator
WATER TREATMENT
Electrical Switchgear
Gas Liquid Separator
Oil
Oil
Filter
Natural Gas Dehydrator
Oily Water
Oil & Water
Transformers
GAS SALES
Pump
Flotation Cell
Gas
Electric Power to Field Operations
Oil, Water & Gas
Gas Compression
Flowing Well
Waste Water
Artificial Lift Pumping Unit
Wellhead
Injection Wells
Gas
Water
TYPICAL ONSHORE OIL FIELD PRODUCTION FACILITIES
RESERVOIR CONTAINING OIL & GAS
Water
Water

Figure C-12.

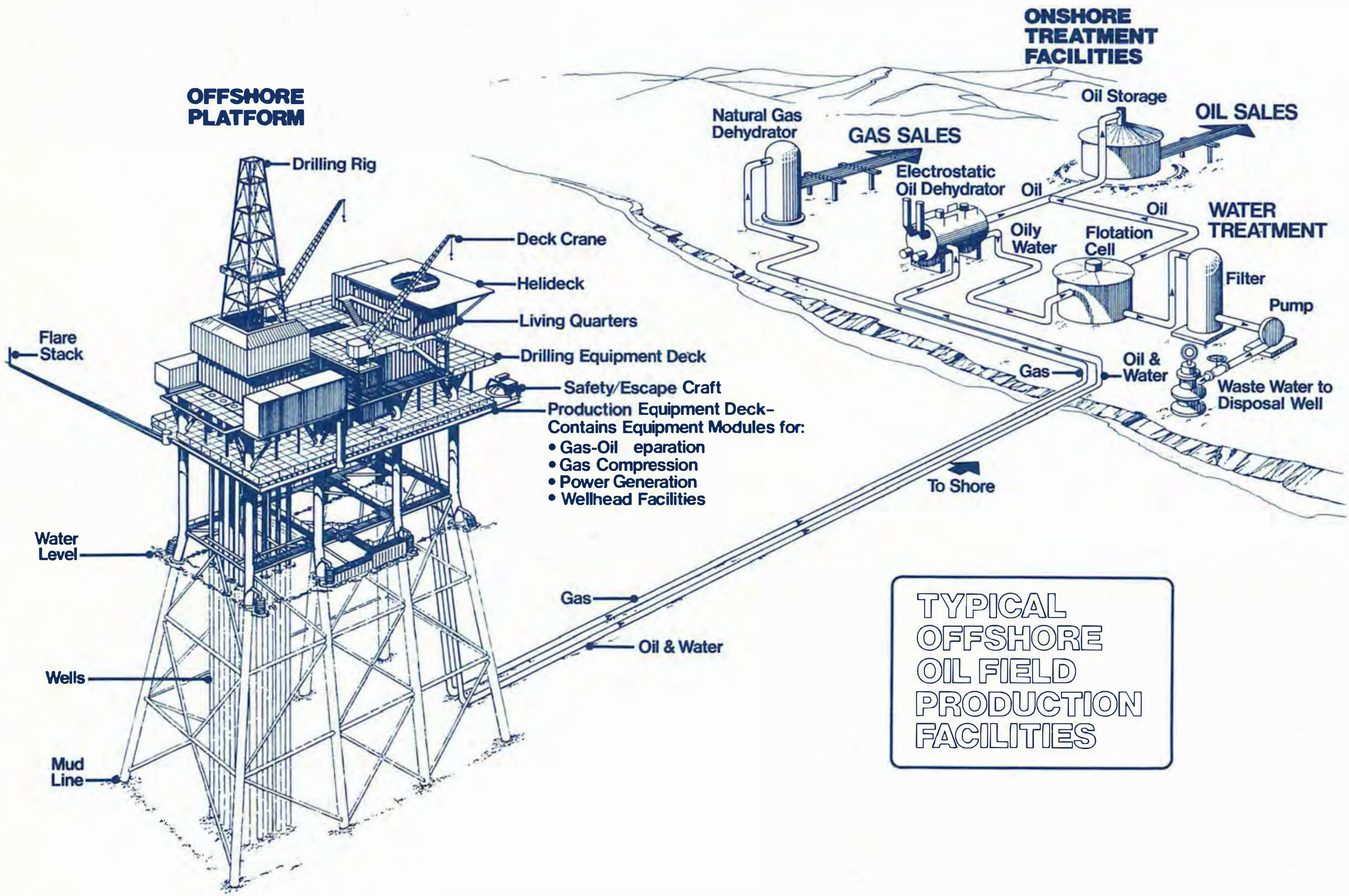

OFFSHORE PLATFORM
Drilling Rig
Deck Crane
Helideck
Living Quarters
Flare Stack
Drilling Equipment Deck
Safety/Escape Craft
Production Equipment Deck-
Contains Equipment Modules for:
• Gas-Oil eparation
• Gas Compression
• Power Generation
• Wellhead Facilities
Water Level
Wells
Mud Line
Gas
Oil & Water
ONSHORE TREATMENT FACILITIES
Natural Gas Dehydrator
GAS SALES
Oil Storage
OIL SALES
Electrostatic Oil Dehydrator
Oil
Oil
Oily Water
Flotation Cell
WATER TREATMENT
Filter
Pump
Gas
Oil & Water
Waste Water to Disposal Well
To Shore
TYPICAL OFFSHORE OIL FIELD PRODUCTION FACILITIES

Figure C-13.

The description and function of drill pipe are presented previously in this appendix. Typical usage is illustrated in Figure C-10.

Casing is installed for a number of reasons, but primarily as a structural material to prevent collapse of the bore hole. Tubing is installed in successful wells to bring oil and/or gas to the surface. Typical usage of casing and tubing is illustrated in Figure C-11.

About 70 percent of casing and tubing is manufactured as seamless material; electric resistance weld material (ERW) and a small amount of continuous weld (CW) make up the balance. OCTG is currently manufactured by 14 companies with substantial variances in capacity.

Casing remains cemented in place in a successful well until the well ceases to produce and is plugged. Some casing is recoverable from abandoned wells and may have certain re-use potential.

Tubing is required only for successful wells and has both an initial and a replacement (from wear and corrosion) demand factor. Tubing is recovered from abandoned wells and generally re-used in service commensurate with its condition.

Drill pipe wears out in use. Its demand factor includes both the replacement of worn out drill pipe and the providing of drill pipe to newly constructed rigs.

The selection of sizes, weight per foot (wall thickness), grades, and end finishes (threaded connections) of these products is based on engineering designs which take into consideration the expected depth of the well, the geological formation in which it is being drilled, and the variety of pressures, temperatures, fluids, and hostile environments which may be encountered.

Production Equipment

The equipment and materials included in this category are the equipment (excluding tubular goods) required to produce oil and gas from underground reservoirs, separate and treat produced fluids, and deliver the merchantable oil and gas to the point of custody transfer. Figure C-12 is a simplified sketch of typical onshore oilfield production facilities. The production and treatment processes are relatively complex, requiring operation and management of a varied array of equipment, machinery, piping, and control systems and associated support equipment. The relationship of major items used in well completions are shown in Figure C-4, oil production facilities in Figure C-5, gas production facilities in Figure C-6, and artificial lift in Figure C-7.

In nearly all oilfields of the United States, oil, water, and gas are produced together. This is due to the nature of the fluids and the mechanics of flow in the porous reservoir rock. An oil well will produce either on natural flow or require an artificial lift method. Approximately 94 percent of the operating oil wells in the United States are produced with some form of artificial lift. Walking beam type pumps, like the one shown in Figure C-12, account for 86 percent of all oil wells on artificial lift. Other methods include gas lift, submersible electric pumps, and downhole hydraulic pumps. After the fluids reach the surface, processing of the wellhead effluent requires the surface equipment shown. The layout of equipment is highly simplified, but the diagram shows the many steps involved in the treatment of produced fluids prior to reinjection or sale.

In addition to the basic equipment systems shown, several additional operations are often required to effectively process the oil, gas, and water. These include: chemical injection at various points in the flowstream to separate oil from oil/water emulsions that sometimes are formed and to protect against corrosion; heating of the oil/water flowstream to separate and break emulsions from within the oil and water mixture; and metering and control systems to measure production volumes and to provide integrated control of the entire operation.

An offshore location, shown in Figure C-13, is very similar in concept and scope to that described above. The major difference is that the oil or gas field is located offshore, under water. Platforms are now located from less than one mile to about 130 miles offshore. Offshore platforms are constructed in a variety of sizes, shapes, and water depths. Currently, typical water depth for a new platform installation is 200 feet. Platform installations have been made in water depths over 1,000 feet, and designs are in progress for 1,200-foot depths.

Wells are drilled from, and primary producing facilities are located on, the offshore platform as shown in Figure C-13. As indicated, primary gas/oil separation, power generation, and other associated basic support facilities, including crew living quarters, are usually located offshore, on the platform. Where feasible, final treatment of the gas, crude, and water prior to sale or other disposition is handled at onshore facilities. The comments made for the onshore treating facilities of Figure C-12 also apply here. More complex facilities are required for producing in locations where onshore separation and treating is not feasible.

The following sections summarize the functions of each industry segment to provide a better understanding of how each fits into the overall oil and gas business.

Offshore Platforms

Offshore platforms are massive structures which provide operations bases in offshore oil and gas fields. This allows development of remote offshore reserves with common, conventional oilfield equipment. Platform sizes vary greatly, largely dependent upon water depth and the number of wells required to develop the reservoir efficiently. Platform size is also influenced by sea-bottom conditions, wind and current loading, and the type of equipment installed on the production and drilling decks. Steel used in these structures can vary from a typical 3,000 tons in 175-200 feet of water to more than 25,000 tons for platforms in 1,000 feet of water. The operations decks on these structures are complex, yet compact. Facilities that would normally cover substantially more area onshore fit into a few thousand square feet on an offshore platform. The complexity of the system, including a redundancy of safety and pollution control equipment, and the required compactness are part of what makes offshore installations so costly to build and operate.

The structural components of an offshore structure, excluding the drilling and production equipment, include legs, bracing, decks, helicopter pads, stairs/walkways, landing stages, fenders, cranes, davits, superstructures, and other fixed equipment or facilities.

Prime Movers

Prime movers, consisting of gasoline, diesel, natural gas, or LPG fueled internal combustion and combustion gas turbine engines, power many types of oilfield equipment. In areas where large and reliable sources of electricity are available, electric motors are replacing these engines as a source of power. The recent increases in the price of natural gas have also contributed to the influx of electrically driven equipment in the oilfield. Internal combustion equipment is used primarily in remote onshore areas and, on offshore platforms, it drives electric generators.

Electrical Equipment

With increased complexity in operations and increasing use of computerized controls, electrical equipment plays an increasingly important role in the oilfield. Transformers, line starters, circuit breakers, meters, conductor cables, electric motors, and motor skids are used in oilfield production operations on pumping units, surface shipping/transfer pumps (oil or water), water well pumps, small booster compressors, and tank mixers. Most of this equipment is mounted in explosion-proof housing but has standard, industrial duty specifications.

Valves and Wellheads

This equipment is used primarily to regulate and control well production and fluid flow in general field operations.

The wellhead provides a means of attaching blowout prevention equipment during drilling of the well and, later, a means to install production control valves (Christmas tree) to safely operate the well. Wellhead equipment includes casing and tubing landing heads, casing and tubing hangers, side outlet flanges, steel tees and crosses, stud bolts and nuts, and steel ring gaskets. The Christmas tree includes tubing master valves, wing valves, flow controllers (adjustable and fixed chokes), and differential shut-off valves (surface safety valves).

Production facility valves (plug valves, gate valves, and ball valves) for oil and gas production manifolds, test manifolds, and water or gas injection manifolds were also covered by the study.

Surface Oil and Gas Production Equipment

This segment consists of the equipment required to treat and process oil and gas and to transport it to custody transfer or other disposition. Much of this equipment is operated through complex control systems to balance throughput with product output quality.

This segment can be divided into five product groups, as follows:

- Surface Oil/Gas Handling Equipment: Oil/gas/water separators, including baffles, floats and level controls, meters, and samplers; direct and indirect fired heaters; water knock-outs; treaters and heater treaters; tanks, baffles, hatches, coils, ladders, stairs/walkways; custody transfer metering units, including provers; and integral piping on all of the above items. Also includes gas dehydration systems (low temperature separation scrubbers, glycol systems, etc.).
- Water Treating Equipment: Filters, small circulating pumps, backwash and slurry tanks, mixing tanks, water softening equipment, control equipment, meters, integral piping, and skid-mounted, packaged units.
- Pumps: All centrifugal, positive displacement, worm gear, or other pumps used in oil-field production operations for surface movement of fluids and subsurface injection of fluids. Includes water source pumps for water and steam injection operations.
- Compressors: All centrifugal, piston type, or other compressors used for downhole injection of gas for pressure maintenance or storage, and for compressing gas to pipeline or injection pressures.
- Steam Generators for Use in Thermal Stimulation of Oil Production: Control equipment, safety shutdown systems, skids, integral piping, fittings, and metering equipment.

Production Chemicals

Production chemicals are chemicals used in production operations to aid in separation and processing of produced fluids, to protect equipment from internal corrosion, and to treat waste products to make them suitable for disposal. These materials are largely petroleum base chemicals, making this industry segment very sensitive to fluctuations in the crude oil supply. Materials specifically investigated included paraffin inhibitors, emulsion breakers, scale and corrosion inhibitors, and all chemicals associated with primary, secondary, and tertiary recovery.

Artificial Lift Equipment

As reservoir energy depletes and wells stop flowing, artificial lift equipment is required to maintain production. This equipment pumps liquid from the bottom of a well to the surface. A variety of methods are used. The most common is the walking-beam type pumping unit. The equipment used with this pumping technique includes:

- Beam pumping units (counter-balanced either by weights on beam or crank, or by air or hydraulic cylinders), pumping jacks, gear reducers, motor rails, skids, carrier bar, surface hydraulic cylinder pumping units complete with wellhead mounting bracket, hydraulic pump and polished rod connector, equipment guards, and skids
- Sucker rod strings, suspended from the pumping unit to actuate the down hole pump: polished rods, pony rods, sucker rods, rod couplings, pull rods, and hollow rods
- Sucker rod pumps (downhole pumps) and parts, including barrel tubes, liners, cages, balls, seats, plungers, etc.
- Miscellaneous equipment such as paraffin scrapers, pump holddowns, rod centralizers, polished rod clamps, rod rotators, stuffing boxes, and fishing tools.

Where sufficient gas volumes are available, gas lift may be used for artificial lift. This lift method uses gas injected into the wellbore fluid near the bottom of the well to reduce the overall density of the fluid in the well, thereby allowing it to be lifted to the surface by formation pressure. Specific equipment used includes surface flow controllers, meters and intermitters, subsurface tubing mandrels, gas lift valves, kick-off valves, blank valves, and check valves. In plunger lift installations, it also includes wellhead plunger, catcher, tubing shoe, and plunger.

Other artificial lift methods that are commonly used employ submersible electric pumps or hydraulic downhole pumps. The electrical pumps consist of specially designed electric motors which drive multi-stage centrifugal pumps. These pumps also require electrical control panels, downhole electrical cable, cable clamps, a gas separator, seals, screens, and anchors. The hydraulic systems use a high pressure liquid to drive a reciprocating pump at the bottom of the well. This type of artificial lift uses surface and subsurface hydraulic pumping equipment, macaroni tubing (small diameter tubing), hydraulic fluid control equipment such as volume/pressure controllers, wellhead lubricator and valves, seating shoe, tubing-macaroni clamps, and tubing-macaroni mandrels.

Subsurface Production Equipment

Subsurface accessory equipment (in addition to well tubulars) is used to safely control fluid production from the reservoir to the wellhead. This equipment can be categorized as follows:

- Packers, which provide a seal between the production tubing and well casing and are used in essentially all domestic flowing and injection wells
- Subsurface safety valves, which automatically shut in a well in the event of a surface disaster
- Miscellaneous tubing accessories, such as tubing chokes, tubing anchors and catchers, gas anchors, tubing check valves, erosion control joints, flow couplings, locking mandrels, and landing nipples
- Casing and liner completion accessories such as hangers and polished bore receptacles.

Well Servicing and Transportation

The well servicing and transportation industries are composed of a wide diversity of contractors and suppliers. The services and materials provided are required in drilling and completion of new wells, in stimulation, repair and maintenance of existing wells, and in the abandonment of the wells after a reservoir is depleted. The variety of materials and equipment used and services performed is shown in Figure C-8. This industry can be broken into four segments: well servicing rigs; cementing and stimulation (acidizing, fracturing, and high pressure pumping services); specialty services (fishing tools and services, directional drilling, drill stem testing tools and services, and sand control); and transportation (land, air, water).

Well Servicing Rigs

The typical well servicing/workover rig consists of a self-propelled carrier equipped with winches, usually referred to as a drawworks, and a mast which can be hydraulically raised and extended above the wellhead. These rigs are used primarily for remedial work on existing wells. They are capable of removing and replacing downhole production equipment which needs repair, and are utilized to clean out sand, paraffin deposits or water from active wells with a minimum loss of production resulting from downtime. In combination with drilling tools, pumps, and mud tanks, these rigs can deepen or work over a well needing major repair, or they can complete a new well, freeing a drilling rig to move to another location.

Cementing and Stimulation

Cementing in oil and gas wells is used to fill the annular space between the steel casing and the open bore hole so that oil and gas bearing intervals can be sealed off from salt water sands, and is used to prevent pollution of fresh water sands with either salt water or hydrocarbons. Specialized mobile pumping equipment is required to pump the viscous cement slurry into place. In addition to the drilling and completion of new wells, cementing services are used in remedial well service to plug off water or excessive gas production and to repair failures in the original or primary cement job.

Producing well stimulation is done to increase production rates and recovery efficiency. Injection wells are also stimulated to increase fluid injection rates. Acidizing and hydraulic fracturing are the two principal techniques now used. When a well is acidized, acid (mostly hydrochloric with smaller amounts of hydrofluoric acid) is pumped down the well and out into the pore spaces of the reservoir rock. The acid consumes materials which restrict flow through the microscopic pore channels, thereby allowing freer flow of fluids into the well.

When a well is hydraulically fractured, mobile units with large amounts of hydraulic pumping horsepower are used to pump a viscous fluid down the well. This causes the reservoir rock to crack open and propagate a fracture through the rock. Special pumps are used to pump carefully graded coarse sand, or other more specialized propping agents, into the fracture to hold it open after the pumps are shut down. This creates a less resistive path for fluids to flow from the reservoir into the well. Fracturing technology has developed so that as much as one to two million pounds of *frac sand* proppant can be pumped down a well into a reservoir. Fracturing is a significant factor in the oil and gas industry's ability to produce deep gas at rates that economically justify drilling.

Specialized high pressure solids, tolerant pumps, piping, and special mixing and storage equipment are required for well stimulation jobs. High reliability and mobility are required of equipment. On land, truck and trailer rigs are used, while boat- or barge-mounted units are used offshore.

Specialty Services

For this study, specialty services include directional drilling, fishing services, drill stem testing, and sand control services. Directional drilling is used in drilling from offshore platforms and in onshore areas where limited surface area is available for drill sites. Depending on the depth of the reservoir, directional drilling allows wells to produce oil or gas from a portion of the reservoir which may be more than a mile away from the surface location of the well. Equipment used includes downhole hydraulic motors, whipstocks (devices to divert the direction of the drill), and other tools in the drill string. Essential to this technique are instruments for measuring the angle and direction of the hole declination.

Fishing services are used in drilling operations to recover foreign objects or portions of the drill string which accidentally break off and are left in the hole. Fishing is also required to recover sections of tubing or other subsurface production equipment which cannot otherwise be removed from a well during servicing or a workover. The services and tools are usually quite specialized and are provided by well service and independent fishing contractors. Equipment includes impact devices (jars), shock absorbers (bumper subs), mills, and gripping tools (overshots, spears, etc.).

Drill stem testing is used primarily on exploration wells to determine production capability of strata indicated by well logs to contain hydrocarbons. The interval of interest is produced into the drill pipe for a limited period of time. Equipment includes downhole packers and valves, actuated by weight, rotation, or pumping, and instrumentation.

There are a number of methods used to control entry of formation sand into the producing well. The most widely accepted method is the gravel pack, where carefully sorted and graded gravel is pumped between perforated well casing and the formation. This gravel acts as a filter to remove finer formation sand from produced fluids. Materials and equipment used include graded gravel, pumps, and blenders. Formation sand may also be stabilized by plastic consolidation.

Transportation

The oil and gas industry depends on reliable transportation to promptly and safely move men, materials, and machinery to and from the site of operations. A variety of land, air, and water transportation is required to reach the remote, out-of-the-way places where operations are conducted around the clock and under nearly all weather conditions.

Land Vehicles

Land vehicles that provide transportation services to the industry range from passenger cars and light pickup trucks to large trucks and trailers specifically designed for the oilfield. Some specialty services are also provided in the way of large trucks modified for specifically assisting in the rigging up and rigging down of drilling and workover rigs. Generally, contractors and operators own their passenger cars and light trucks, and use trucking contractors for their heavier hauling and transportation of equipment. The heavier vehicles are regulated by both the federal and state governments. Many independent truckers are in the heavy truck transportation industry.

Aircraft

The helicopter is the basic aircraft used by the industry in drilling and production operations. By far, the preponderance of this use is for offshore operations and most are owned and operated by contractors. Aircraft are used primarily to move personnel and small quantities of lightweight materials. Under special circumstances, heavy duty helicopters are used to move larger loads.

Boats

Boats used include tugs, supply boats, and crew boats. The majority of these vessels are used in conjunction with exploration and development in the Gulf of Mexico and throughout the Outer Continental Shelf area. Almost all offshore boats are owned and operated by contractors.

APPENDIX D

Impact of Government Regulation

Impact of Government Regulation

The National Petroleum Council was requested to evaluate the impact of federal policy and business philosophy on the availability of materials and personnel in the exploration and producing industry.

One project was to conduct an attitude survey of the key leaders in exploration and production companies, related service and supply firms, commercial banks, and the academic community. The survey was intended to determine how these leaders modulate their business expansion plans depending on their perception of federal policy. The principal issues examined were:

- The current investment planning practices used in the exploration and production industry
- The outlook of the future business environment
- Estimates of how potential federal actions will influence future investment decisions
- Perceptions of constraints on increased activity in the exploration and production industry.

Separate questionnaires were developed for each of the following: exploration and production companies, service and supply companies, commercial banks, and academic institutions. Each questionnaire was designed to measure the major opinions and concerns that were most relevant to the future domestic activity of the industry.

Companies and institutions were selected as potential respondents to represent a wide cross-section of the industry's activity. Surveys were mailed in May 1979 to the following groups:

- *Exploration and Production Companies*

  All domestic companies that drilled 22 or more wells in 1977 (350 companies), plus a random sample of 116 companies (out of a possible 1,650) that drilled between five and 21 wells in 1977.
- *Service and Supply Companies*

  A total of 110 potential respondents were identified from the comprehensive Arthur D. Little report, *International Outlook for the Oilfield Service and Supply Industry, 1977-1978.*
- *Commercial Banks*

  With the assistance of the Chase Manhattan Bank and the Independent Petroleum Association of America, 83 banks were identified. This list included 37 major banks and 46 regional banks. Each institution was judged to have a strong lending position in the oil and gas industry.
- *Academic Institutions*

  From the official mailing list of the American Society for Engineering Education a total of 130 schools were selected. Each school was judged to have a significant percentage of its graduates in the oil and gas industry.

In addition to broad questions on opinions and concerns, the exploration and production companies were asked, in a separate questionnaire, to quantify in dollars and number of wells drilled the impact of certain regulations on their near-term operations. However, it proved extremely difficult for companies to isolate the tangible impact of individual regulations. Further, since individual regulations affect each operator differently, wide variances in impact data were received. Despite these factors, the quantitative responses were sufficient to support directionally the qualitative responses summarized in this appendix.

Exploration and Production Companies

Demographics of the Sample

The number and distribution of the respondents in the sample are representative of the exploration and production industry as a whole. The 121 respondents, taken together, in 1978 accounted for:

- 21.0 million feet of exploratory drilling
- 44.5 million feet of other drilling
- 9,013 thousand barrels per day in domestic oil production
- 47.3 million thousand cubic feet per day in domestic gas production.

Both large and small companies are represented in the sample. In 1978:

- 71 percent did not have substantial exploration and production interests outside the United States
- 54 percent were significantly involved in acquiring federal and state acreage leases onshore; 31 percent offshore
- 65 percent had exploratory drilling footage of less than 100,000 feet
- 46 percent had total drilling footage of less than 100,000 feet
- 65 percent produced fewer than 5,000 barrels of oil per day
- 67 percent produced fewer than 10,000 thousand cubic feet of gas per day.

Business Environment Outlook

At the time of the survey, the majority of the respondents did not view the future business environment as strongly encouraging to expanded exploration and production activity.

Of the respondents, 64 percent assumed that their overall profit potential would not increase between now and 1985, despite the fact that 85 percent assumed that oil and gas prices would increase between now and 1985. A substantial proportion of respondents assumed that inflation and increased cost of capital and environmental preservation would offset the price rises.

Four scenarios of future business environments were prepared, covering the combinations of improvement/no improvement in profit margins and resolution/no resolution of environmental preservation issues. The responses to the four scenarios of large and small oil and gas producers are summarized in Table D-1.

Large and small exploration and production companies were found to be highly similar to one another in their estimates of their future activity, given the various business environment scenarios.

Scenario 1 is seen as inhibiting future activity. In this scenario, it was assumed that oil and gas pricing structures would allow no improvement in profit margins per unit of production, and environmental protection laws and regulations were not revised such as to positively affect resource development.

Scenario 2, where prices were decontrolled for oil and gas and profit margins were increased significantly, is seen as both increasing the number of investment opportunities and stimulating increased activity.

Scenario 3, where there is a favorable resolution of natural environmental issues, promoting resource development, is seen as both increasing the number of investment opportunities and stimulating increased activity, but not as much as Scenario 2.

Scenario 4, where prices are decontrolled and environmental preservation issues are favorably resolved, is seen as having the greatest positive effect on future activity. The increases in activity and investment opportunities resulting from Scenarios 2, 3, and 4 indicate the industry's confidence in the nation's oil and gas resource base.

Capability of Increased Activity

The vast majority of exploration and production companies asserted that they have the capability of expanding their rate of increased activity between 1980 and 1985.

The factors which are most likely to have an impact on their ability to accelerate increased activity levels are manpower, capital, and rig availability.

The majority of producers (93 percent) anticipate that domestic activity in the United States will increase if the federal government permits market mechanisms to determine profit margins, while 90 percent feel that activity will decrease if the federal government prevents profit margins from rising above current levels.

Service and Supply Companies

Demographics

A representative sample of service and supply companies serving the exploration and production industry was included in the survey. A total of 69 corporate entities, representing 154 exploration and production related businesses, responded to the questionnaire. Of this group of 69 corporations, 32 percent do more than $100 million domestic business per year with the exploration and production industry; 39 percent do less than $50 million.

Between 1973 and 1978, 25 percent of the responding corporations realized revenue growth of less than 15 percent per year; 34 percent had revenue growth of at least 25 percent per year.

Investment Evaluation Practices

The service and supply companies tended to be conservative in the assumptions they made about the business environment between now and 1985. Table D-2 displays the survey results for each service and supply sector examined. In summary:

- 60 percent are not anticipating that their return on capital will increase
- 80 percent anticipate increased competition from other companies
- 77 percent expect cost inflation rates to increase
- 54 percent expect the cost of capital to increase.

Capability of Increased Activity

Factors which are explicitly considered by a majority of respondents before increasing output capacity are: risk of creating unused capacity; indicators of future exploration and production activity; and federal pricing policies.

The factors which are most likely to be seen as having a large impact on the companies' ability to accelerate increased activity levels are skilled labor availability, internally generated cash flow, the availability of other services and supplies, and the availability of managerial personnel.

Commercial Banks

Demographics

Forty-one commercial banks responded to the survey. Of these banks, 42 percent have assets of at least $1 billion and 76 percent have a specific department which services the petroleum exploration and production industry. Forty-two percent have a loan portfolio to the domestic petroleum industry of at least $100 million.

TABLE D-1

EFFECT OF POTENTIAL FEDERAL ACTIONS ON OIL/GAS INVESTMENT ACTIVITY

Measure and Degree of Effect of Federal Action	SCENARIO 1 Neither Profit Margin Improvement Nor Resolution of Environment Preservation Issues • Percentage of Respondents Expecting *Decreased* Activity				SCENARIO 2 Price Decontrol Yielding Significant Profit Margin Improvement Per Unit of Production • Percentage of Respondents Expecting *Increased* Activity			
	Oil Production		Gas Production		Oil Production		Gas Production	
	High Rate	Low Rate *	High Rate	Low Rate †	High Rate	Low Rate *	High Rate	Low Rate †
(A) Exploration								
Number of Investment Opportunities, Increase								
—Very Much	—	—	—	—	62%	64%	60%	71%
—Moderately	—	—	—	—	38	33	38	27
—Total	—	—	—	—	100	97	98	98
1980 Vs 1978 Activity Increase or Decrease								
—Very Much	14%	36%	18%	33%	49	56	48	59
—Moderately	64	42	58	51	51	40	48	39
—Total	78	78	76	84	100	96	96	98
1985 Vs 1978 Activity Increase or Decrease								
—Very Much	73	76	72	80	80	74	82	76
—Moderately	17	12	18	14	20	24	15	23
—Total	90	88	90	94	100	98	97	99
(B) Development								
Number of Investment Opportunities, Increase								
—Very Much	—	—	—	—	52	58	48	55
—Moderately	—	—	—	—	48	34	50	39
—Total	—	—	—	—	100	92	98	94
1980 Vs 1978 Activity Increase or Decrease								
—Very Much	5	26	8	25	37	51	30	53
—Moderately	55	43	50	50	59	41	55	43
—Total	60	69	58	75	96	92	85	96
1985 Vs 1978 Activity Increase or Decrease								
—Very Much	54	68	55	70	80	69	80	74
—Moderately	39	16	38	19	20	25	15	23
—Total	93	84	93	89	100	94	95	97

(C) Production Maintenance								
Number of Investment Opportunities, Increase								
—Very Much	—	—	—	—	31	39	21	41
—Moderately	—	—	—	—	56	38	59	39
—Total	—	—	—	—	87	77	80	80
1980 Vs 1978 Activity Increase or Decrease								
—Very Much	5	15	5	15	25	37	18	37
—Moderately	48	38	40	39	58	41	59	43
—Total	53	53	45	54	83	78	77	80
1985 Vs 1978 Activity Increase or Decrease								
—Very Much	40	49	43	47	48	47	44	44
—Moderately	40	20	35	21	40	37	46	39
—Total	80	69	78	68	88	84	90	83
(D) Recovery Enhancement								
Number of Investment Opportunities, Increase								
—Very Much	—	—	—	—	56	41	31	44
—Moderately	—	—	—	—	44	35	36	35
—Total	—	—	—	—	100	76	67	79
1980 Vs 1978 Activity Increase or Decrease								
—Very Much	25	25	19	23	22	35	14	34
—Moderately	55	42	38	48	72	40	50	44
—Total	80	67	57	71	94	75	64	78
1985 Vs 1978 Activity Increase or Decrease								
—Very Much	78	62	60	64	78	48	50	50
—Moderately	20	13	19	16	22	35	22	34
—Total	98	75	79	80	100	83	72	84
Approximate Number of Respondents	(42)	(76)	(40)	(76)	(42)	(77)	(40)	(75)

* Low Rate Oil Production—Less than 5,000 barrels per day.
† Low Rate Gas Production—Less than 10,000 thousand cubic feet per day.

TABLE D-1 (Continued)

Measure and Degree of Effect of Federal Action	SCENARIO 3 Resolution of Environment Preservation Issues to Promote Oil/Gas Development • Percentage of Respondents Expecting *Increased* Activity				SCENARIO 4 Both Profit Margin Improvement and Resolution of Environment Preservation Issues • Percentage of Respondents Expecting *Increased* Activity			
	Oil Production		Gas Production		Oil Production		Gas Production	
	High Rate	Low Rate *	High Rate	Low Rate †	High Rate	Low Rate *	High Rate	Low Rate †
(A) Exploration								
Number of Investment Opportunities, Increase								
—Very Much	21%	27%	22%	29%	81%	68%	72%	73%
—Moderately	74	48	65	49	19	28	25	24
—Total	95	75	87	78	100	96	97	97
1980 Vs 1978 Activity Increase or Decrease								
—Very Much	19	21	18	23	64	62	55	65
—Moderately	64	59	60	59	36	34	42	32
—Total	83	80	78	82	100	96	97	97
1985 Vs 1978 Activity Increase or Decrease								
—Very Much	32	36	32	37	93	83	92	85
—Moderately	58	52	55	54	7	14	5	14
—Total	90	88	87	91	100	97	97	99
(B) Development								
Number of Investment Opportunities, Increase								
—Very Much	5	22	3	25	68	65	65	63
—Moderately	81	45	80	46	32	26	33	30
—Total	86	77	83	71	100	91	98	93
1980 Vs 1978 Activity Increase or Decrease								
—Very Much	5	15	5	16	52	60	43	63
—Moderately	68	53	60	58	43	33	45	33
—Total	73	68	65	74	95	93	88	96
1985 Vs 1978 Activity Increase or Decrease								
—Very Much	20	26	20	27	95	79	93	82
—Moderately	71	53	68	54	5	17	5	15
—Total	91	79	88	81	100	96	98	97

(C) Production Maintenance								
Number of Investment Opportunities, Increase								
—Very Much	3	17	0	17	38	49	30	46
—Moderately	49	35	39	39	50	32	53	36
—Total	52	52	39	56	88	81	83	82
1980 Vs 1978 Activity Increase or Decrease								
—Very Much	3	16	0	13	38	45	28	44
—Moderately	53	38	41	42	45	32	49	33
—Total	56	54	41	55	83	77	77	77
1985 Vs 1978 Activity Increase or Decrease								
—Very Much	10	22	8	18	60	55	59	54
—Moderately	60	43	56	49	28	28	31	27
—Total	70	65	64	67	88	83	90	81
(D) Recovery Enhancement								
Number of Investment Opportunities, Increase								
—Very Much	10	22	0	19	62	45	38	46
—Moderately	62	36	39	38	38	38	32	36
—Total	72	58	39	57	100	83	70	82
1980 Vs 1978 Activity Increase or Decrease								
—Very Much	8	14	0	11	35	41	22	40
—Moderately	62	40	33	44	60	38	47	38
—Total	70	54	33	55	95	79	69	78
1985 Vs 1978 Activity Increase or Decrease								
—Very Much	20	20	11	16	88	56	61	59
—Moderately	65	46	47	52	12	30	14	27
—Total	85	66	58	68	100	86	75	86
Approximate Number of Respondents	(42)	(75)	(40)	(73)	(42)	(77)	(40)	(75)

* Low Rate Oil Production—Less than 5,000 barrels per day.
† Low Rate Gas Production—Less than 10,000 thousand cubic feet per day.

TABLE D-2

ASSUMPTIONS MADE REGARDING INCREASE IN CERTAIN FACTORS IN PLANNING EXPANSION OF ACTIVITY BETWEEN NOW AND 1985

	Total	Con-tract Drill	Rigs/ Equip.	Drill Bits Oil Tools	Cement Stim.	Tubu-lar Goods	Comple-tion, Work-over, Mainte-nance
Domestic demand for E&P services and supplies	92%	93%	84%	100%	100%	100%	100%
Foreign demand for E&P services and supplies	79	79	83	93	100	71	64
Cost inflation rates	77	89	84	57	50	43	64
Tax structure and rates	38	44	46	21	0	17	50
Cost of capital	54	59	67	29	25	14	57
Natural environment preservation issues	56	70	58	71	50	43	43
Competition from other companies	80	93	71	71	100	86	86
Industry production-to-capacity ratio (if your capacity is not increased)	47	61	50	31	25	57	62
Return on capital	40	57	32	29	25	29	50
Approximate Number of Respondents	(154)	(28)	(25)	(14)	(4)	(7)	(14)

Lending Practices

In evaluating a company's creditworthiness, large independents are scrutinized more stringently than are majors. Small independents are examined even more closely than are large independents. Quality of management, cash flow projection, value of revenues, and earning performance are key variables in evaluating majors, large independents, and small independents. (See Tables D-3, D-4, and D-5.)

Constraints on Increased Lending

The larger the exploration and production company, the less likely that an institution will fail to approve a credit request. Insufficient projected cash flow appears to be the primary reason. If profit margins for domestic crude oil were increased significantly through decontrol, most banks predict that they would increase their exploration and production portfolio.

Most bankers agree that demand for external financing is inhibited by an insufficiently high price for crude oil and by regulatory paperwork.

In citing factors which discourage exploration and production expansion, 78 percent of the bankers mentioned that domestic crude pricing is too low and 71 percent mentioned regulatory paperwork.

Potential Federal Policies

The vast majority of bankers view crude oil price controls as inhibiting to the exploration and production industry, and the decontrol of oil pricing as encouraging to exploration and production activity expansion. Continued price controls are cited by 51 percent of the respondents as one of the key actions the federal government could take which would most weaken the creditworthiness of the exploration and production industry.

Similarly, enacting restrictive environmental preservation laws is cited by 24 percent of the bankers as being one of the key actions the federal government could take to weaken the credit-worthiness of the exploration and production industry.

TABLE D-3

FACTORS SEEN AS IMPORTANT IN EVALUATING A MAJOR EXPLORATION AND PRODUCTION COMPANY'S CREDIT WORTHINESS

		Region		Portfolio	
	Total	SW	Other	Large	Small
Size of company	15%	21%	6%	29%	4%
Diversification of business	5	8	0	6	4
Quality of management	36	38	35	47	26
Earning performance	32	33	29	35	26
Growth potential	10	12	6	6	9
Debt-to-equity ratio	17	21	12	6	22
Cash flow projection	32	38	24	41	22
Quality of collateral/guarantee	20	25	12	24	13
Value of reserve	20	25	12	18	17
Other (specify)	5	4	6	6	0
Approximate Number of Respondents	(41)	(24)	(17)	(17)	(23)

TABLE D-4

FACTORS SEEN AS IMPORTANT IN EVALUATING A LARGE INDEPENDENT EXPLORATION AND PRODUCTION COMPANY'S CREDIT WORTHINESS

		Region		Portfolio	
	Total	SW	Other	Large	Small
Size of company	12%	17%	6%	24%	4%
Diversification of business	7	4	12	6	9
Quality of management	54	54	53	82	30
Earning performance	37	29	47	47	26
Growth potential	22	21	24	29	13
Debt-to-equity ratio	22	12	35	29	13
Cash flow projection	44	50	35	71	22
Quality of collateral/guarantee	39	46	29	65	17
Value of reserve	49	54	41	76	26
Other (specify)	5	4	6	6	0
Approximate Number of Respondents	(41)	(24)	(17)	(17)	(23)

TABLE D-5

FACTORS SEEN AS IMPORTANT IN EVALUATING A SMALL INDEPENDENT EXPLORATION AND PRODUCTION COMPANY'S CREDIT WORTHINESS

		Region		Portfolio	
	Total	SW	Other	Large	Small
Size of company	12%	12%	12%	24%	4%
Diversification of business	12	12	12	18	9
Quality of management	88	92	82	94	83
Earning performance	56	62	47	47	61
Growth potential	49	54	41	59	39
Debt-to-equity ratio	42	33	53	35	44
Cash flow projection	83	83	82	82	83
Quality of collateral/guarantee	85	92	76	88	83
Value of reserve	85	88	82	94	78
Other (specify)	7	8	6	6	4
Approximate Number of Respondents	(41)	(24)	(17)	(17)	(23)

Academic Institutions

Demographics

A representative sample of academic institutions producing bachelor level or higher engineering graduates was included in the survey. One hundred-and-one institutions responded to the questionnaire, of which 31 percent were private institutions.

Fifty-nine percent of the institutions had between 1,000 and 2,500 full-time engineering students, and 88 percent had no formal retraining program to prepare engineers for the petroleum industry.

The Planning Process

Engineering institutions tend to plan for their enrollment capacity far in advance and re-evaluate these plans no more often than yearly. In planning the future output of engineers, student interest and the institution's budget are most likely to be explicitly considered.

Ninety-two percent of the academic institutions consider the number of students selecting engineering and science majors and 38 percent view this as a major constraint to producing larger numbers of engineers.

Seventy-nine percent consider the institution's budget for expansion. The major constraints to expansion are believed to be:

- The institution's internal funding (70 percent)
- The physical facilities (54 percent)
- The availability of qualified faculty (41 percent).

Most academic institutions would need several years to significantly increase their output of engineers. To increase production capacity by 25 percent:

- 59 percent would need at least 3 years
- 18 percent would need at least 5 years.

More funding is viewed as the single factor that would do the most to increase the output of engineering and science professionals. The respondents mentioned the following factors:

- 33 percent, more general funds
- 28 percent, more building funds
- 26 percent, more funds for faculty.

APPENDIX E

Additional Background on Drilling Activity Outlook Projections

Additional Background on Drilling Activity Outlook Projections

Contents

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TABLE E-1

COMPARISON OF DRILLING ACTIVITY FORECASTS

Study Number	Date	Type	Range	Oil Price	Gas Price	Forecast Method	Leading Variable	Reserve Base
1	6/78	Wells & footage	1978-87	U.S. prices increase at or above inflation. OPEC controlled world price.	Increase at or above inflation. **Gas bill** expected to have **positive** impact.	**Subjective** assessment of 6-8%/yr maximum sustainable long-term growth.	Wells & footage	Substantial potential. Declining quality. No major discoveries onshore or offshore. Cont'd R/P decline.
2	7/78	Wells & footage	1978-87	**Deregulated** after 5/79.	Intrastate deregulated; interstate increased substantially by new law or deregulation.	Mechanically project rigs, drilling, prod. Test activity w/energy balance & econometric model.	Drilling rig building capacity (from survey of manufacturers).	**Lower 48 only.** Decline of reserves reversed by mid-1980's for both oil (EOR) and gas (drilling).
3	12/78	Wells & footage	1979-90	Decontrol upper tier 5/79; 18 mo. to OPEC "world" price. Lower tier **regulated** escalates at 10%/yr.	Per 1978 NGPA.	Mathematical projection of activity based on price forecast & regression fit to 1947-78 price/activity history. **Assumes exhaustion of infill locations after 1983.**	Prices & infill drilling opportunities.	
4	4/78	Footage	1977-90	Continue regulation per 1977 laws and practices.	Intrastate deregulated; interstate under FPC Opinion 770A.	Drill all **new field footage** which produces at least 8% real AFIT rate of return.	Drilling rigs prices, and net cash flow.	USGS "most probable" (50/50).
5	2/78	Footage	1977-95	N/A	N/A	Arithmetically avg'd 3 other drilling footage forecasts.	N/A	N/A
6	2/78	Footage	1978-85	Continued regulated, add 3rd tier; increase w/inflation rate of 5-½%/yr.	Single market at $1.75/MCF on 4/77, per President Carter's proposed gas bill.	Drill all **new field footage** which produces at least 8% real AFIT rate of return.	Drilling rigs, prices and net cash flow.	USGS "most probable" (50/50).

N/A—Not specifically addressed.

TABLE E-1 (continued)

Study Number	OCS Lease Rate	Federal Land Access	Physical Constraints	Effect of Foreign Demand	Drilling Technology	EOR or Unconventional Gas Drilling	Other
1	N/A	N/A	(a) concern about skilled manpower; (b) capital availability.	Increasing, but not damaging to U.S. growth.	Improvement will not radically increase output.	Insignificant until late 1980's.	
2	N/A	N/A	None	No change in current balance—expect U.S. to be as attractive as foreign due to prices & security.	**15% increase in footage per rig** in next 10 yrs—bits, MWD, retrofitting & retirement of old, less efficient rigs.	Increased oil recovery factors; however, did not specifically identify EOR footage or wells.	
3	1.1MM a./yr 400M GOM & 700M frontier.	Increase at 2%/yr; current rate 4.6%/yr.	None	N/A	Rig productivity remains at 1978 levels. Increases in onshore productivity to be offset by increased GOM activity.	Not included.	**Average well depth** remains **constant** at 1978 levels (seems to contradict infill drilling & GOM activity assumptions).
4	Per DOE ('77) 8.5MM a. by '81, 1MM a./yr thereafter.	N/A	None	N/A	Relatively constant—no breakthroughs.	Not specifically identified, but EOR reserves included in reserve base.	
5	N/A	N/A	(a) rapidly increasing costs; (b) increased activity in deep and hostile environments; (c) severe industry fragmentation; (d) skilled manpower; (e) materials; (f) rigs.	Expect increased foreign demand in mid-1980's.	Private industry R&D will produce no significant breakthroughs to increase drilling productivity.	Not included.	
6	Per DOE ('77) 8.5MM a. by '81, 1MM a./yr thereafter.	N/A	None	N/A	N/A	Not specifically identified, but EOR reserves included in reserve base.	

N/A—Not specifically addressed.

TABLE E-1 (continued)

Study Number	Date	Type	Range	Oil Price	Gas Price	Forecast Method	Leading Variable	Reserve Base
7	10/78	Wells & footage	1978-79	N/A	Energy bill will not constrain activity.	Extrapolate historic 12%/yr growth rate in wells drilled.	History	N/A
8	11/77	Footage	1977-86	Continued regulated.	Gas bill expected to provide incentive for drilling.	Subjective downward adjustment of forecast in study # 17 for impact of physical constraints indicated. Expect infill drilling to decline from current levels.	Prices & historic footage /$/B new field wildcat.	N/A
9	8/78	Wells & footage	1978-83	Continued regulated with 6.5%/yr avg increase through 1983.	Assumed 1978 NGPA would not have a negative impact on drilling activity.	Subjective forecast considering leading variables, reinvestment rates, & current business trends.	Wellhead revenue, rig & crew availability.	N/A
10	1/79	Wells	1978-85	Continued regulated w/slight improvements by 1985.	1978 NGPA w/assumption that current gas surplus will ease with granting of exemptions to oil/coal conversion policies.	Subjective with "conscious effort to be conservative."	Political events, rig productivity & supply.	N/A
11	7/77	Wells	1977-85	Continued regulated, but increase at 5%/yr over inflation.	Continued regulated interstate w/avg price increasing 5%/yr over inflation.	Increase drilling by 2,500 oil & 1,250 gas wells/yr. "Roughly parallels increases since 1973."	Domestic production increase req'd to meet President Carter's import reduction goal.	Lower 48 states only.
12	9/78	Footage	1979-83	Continued regulated, increasing with inflation.	1978 NGPA would cause no significant changes. Prices would increase w/inflation.	Project historic trend of rig activity and productivity. Determine footage from these projections.	Drilling rig utilization and productivity.	N/A

N/A—Not specifically addressed.

TABLE E-1 (continued)

Study Number	OCS Lease Rate	Federal Land Access	Physical Constraints	Effect of Foreign Demand	Drilling Technology	EOR or Unconventional Gas Drilling	Other
7	N/A	N/A	None	No change from 1978.	Improvements expected in response to demand & utilization as well as unspecified technology developments.	N/A	
8	N/A	N/A	(a) rig & component delivery times through 1980; (b) manpower to operate rigs; (c) oil country tubular goods after 1982.	N/A	Include 5.5% increase in rig performance.		
9	Not a factor during next 5 yrs.	Not a factor during next 5 yrs.	Possibly manpower—inexperienced drilling crews reduce rig productivity.	N/A	Expected 1.5-2.0%/yr increase in rig productivity from technology improvement, other factors being held constant.	Neither activity very significant in next 5 yrs.	Higher than usual levels of exploratory drilling will limit growth in wells drilled through 1980, after which development drilling increases through 1983.
10	N/A	N/A	No serious long-term constraints; drill pipe, hooks, pump bodies now tight.	No change in U.S. position in oil tool market.	Small improvements will be offset by increased well depth.	EOR included, but considered insignificant prior to 1985.	
11	N/A	N/A	None	N/A	N/A	N/A	Limited wellhead revenue & increasing drilling cost will prevent growth at levels req'd to meet import reduction goal.
12	N/A	N/A	None	N/A	N/A	N/A	

N/A—Not specifically addressed.

TABLE E-1 (continued)

Study Number	Date	Type	Range	Oil Price	Gas Price	Forecast Method	Leading Variable	Reserve Base
13	3/78	Wells & footage	1978-90	Regulated, but increase to world levels by mid-1980's.	New gas at Btu parity w/oil. All other categories per laws in effect on 3/78.	Determine footage by ratio of reserve adds from Exxon & Shell & finding rates from Rotan Mosle (11/23/77).	Reserve additions and finding rates.	Exxon and Shell
14	1/79	Wells & footage	1979	Regulated.	1978 NGPA not a stimulus due to confusion it causes.	Survey 300 oil companies to determine industry trends. Subjectively scale up to industry total considering 300 company trend, recent rig activity, & governmental activities.	Plans of 300 oil companies.	N/A
15	1/79	Wells & footage	1979-90	Controlled through 1985; decontrolled thereafter.	1978 NGPA, new gas at Btu parity w/distillate by 1987.	Subjectively forecast reserve additions. Calculate footage from reserve adds & forecast finding rates. Forecast avg depth to calculate wells drilled.	Gov't/business environment, reserve adds and finding rates.	Discounted USGS reserves. Discount tertiary & frontier OCS.
16	10/78	Wells & footage	1978-79	Unchanged.	Higher interstate prices expected.	Forecast rig adds, attrition & performance (ft/rig & wells/rig) & calculate wells & footage drilled.	Reed Rig Census, rig utilization & rig performance history.	N/A
17	7/77	Wells & footage	1977-90	Upper tier at $13.50/B (1977) escalate w/inflation.	New gas between $1.75/MCF & Btu parity, escalate w/inflation.	Complex procedure involving numerous projections of historic trends & empirical relationships between wildcat & development drilling.	Prices & historic footage/$/B new field wildcat.	N/A
18	7/78	Footage	1978-90	Regulated but more favorable than current system by 1980, also special EOR incentives.	Gas bill expected to provide some incentive to expand drilling.	Subjective adjustment of footage forecast in study #17. Check against Exxon & Shell energy supply balance w/Rotan Mosle finding rates.	Knowledge & perception of trends in industry.	Indirectly Exxon & Shell energy outlooks.

N/A—Not specifically addressed.

TABLE E-1 (continued)

Study Number	OCS Lease Rate	Federal Land Access	Physical Constraints	Effect of Foreign Demand	Drilling Technology	EOR or Unconventional Gas Drilling	Other
13	Lease rates will not limit activity.	N/A	None	N/A	N/A	Not specifically identified, but EOR reserves included in reserve base.	Avg well depth to increase 30% over 1960 avg by 1990.
14	N/A	N/A	None	Will not limit or constrain growth.	1979 rig performance will be 4% better than 1978 due to technology, increasing numbers of new rigs, & high levels of shallow drilling.	N/A	
15	DOI's* current schedule adj. for perception of delays (10-12 yrs from leasing to production).	N/A	None; industry can overcome this type of constraint within 1-3 yrs.	N/A	No significant improvements.	Not specifically identified, but EOR reserves included in reserve adds after 1985.	Footage growth will slow in mid-1980's as finding rates decline. Wells will level off because of reduced footage growth & increasing avg depth.
16	N/A	N/A	(a) manpower on rigs-critical; (b) drill pipe-steel mills now at capacity.	Continue at 20-25% of all new rigs and components.	No dramatic increase in rig productivity.	N/A	
17	N/A	N/A	None	Strong domestic demand will compete favorably w/foreign markets.	Improvements will only affect number of rigs active.	Not included.	Without 23.5% oil price increase in 1979 forecast, activity cannot be expected. 1978 NGPA probably disincentive to rapid expansion by producers.
18	No more restricted than now.	No more restricted than now.	Assume lead times get no worse than now.	Status quo.	Improvements not likely to offset the increasing cost of equipment & materials.	Expect limited EOR drilling in late 1980's.	

N/A—Not specifically addressed.
*DOI—Department of the Interior.

TABLE E-1 (continued)

Study Number	Date	Type	Range	Oil Price	Gas Price	Forecast Method	Leading Variable	Reserve Base
19	10/78	Wells & footage	1978-85	Regulated, but with escalation of 10%/yr through 1982, declining to 7% by 1985.	Per anticipated compromise bill.	Regression model using "various combinations of price, production, & investment history." Use highest historical correlation to project future.	Prices, production, & drilling expenditure history.	Use proprietary models.
20	10/78	Footage	1978-80	Continued attractive.	Continued attractive.	Subjective forecast considers recent activity levels, announced budgets, & other input from producers & pending gov't actions.		N/A
21	2/79	Wells & footage	1979	Continued regulated.	1978 NGPA is providing incentive for some growth in drilling.	Scale up plans for wells of producers surveyed based on fraction of prior yr's activity represented in each state. Subjectively adjust for local factors. Forecast footage using prior yr's avg depth by state.	Plans of operators & prior years' activity trends.	N/A
22	1/79	Wells & footage	1979-90	Regulated, with 10%/yr escalation.	Escalate avg price per historic trend—probably not consistent w/1978 NGPA.	Forecast industry revenue from Exxon & Shell projections of U.S. production & own forecast of prices. Extrapolate historic trend of drilling expenditures as % of production revenue & cost/ft to get footage.	Price & future production.	Exxon and Shell
23	2/79	Wells	1979	No change from 1978.	Per 1978 NGPA—recognize uncertainty but not necessarily worse than 1978.	Subjective forecast—lower than 1978 growth rate, but above rate calculated from expected rig additions & 16.9 active rig days/well experienced in 1978.		N/A

N/A—Not specifically addressed.

TABLE E-1 (continued)

Study Number	OCS Lease Rate	Federal Land Access	Physical Constraints	Effect of Foreign Demand	Drilling Technology	EOR or Unconventional Gas Drilling	Other
19	Per model	Per model		N/A	Continue historic trend in technology growth.	Not specifically identified but EOR reserves included.	
20	N/A	N/A	None. However (a) gas surplus in Southwest; (b) uncertainties in gas bill; and (c) capital availability may present disincentive for drilling growth.	No problems.	Modest improvements.	N/A	
21	N/A	N/A	None	Mexican plans to buy numerous rigs from U.S. rig manufacturers could cause lead time problems for U.S. orders.	Completion technology for tight gas could open new drilling growth area.	No change from current impact.	
22	N/A	N/A	None	No problems.	Rig performance (ft/rig) to increase 20% by 1990 while wells/rig continue to decline due to regulations, frontier environments, & well depth.	None	
23	N/A	N/A—presents downside risk.	Rate of delivery of new rigs.	N/A	Improved bits will balance well mix changes to hold rig days/well at or above 1978 level.	N/A	Expect substantial shallow drilling due to lower cost/well & increasing stripper oil prices.

N/A—Not specifically addressed.

Projected Drilling Activity by NPC Region

Drilling activity was projected for each NPC Region shown in Figure E-1 and Table E-2, to determine possible oil country tubular demand from data on regional consumption, and to project drilling activity by an alternate method for use as a cross-check against the U.S. total activity projection described in Chapter One.

Projection Method

A projection of wells drilled by NPC Region at the upper level of the activity range was made by extending the 1970-1978 trends of the percentage of U.S. total wells drilled in each NPC Region through 1981. These projections were made considering the possible response of the industry to the upper level business conditions. Recent developments such as the Overthrust Belt, the Tuscaloosa Trend, growth in deep drilling in the Anadarko Basin, etc., were also considered in the projections. In addition, factors which have significantly influenced prior activity levels, such as the development of the Elk Hills field in California, the completion of waterflood implementation in many major fields, the impact of the intrastate gas surplus on Texas and Louisiana drilling, the infield drilling boom, and the release of stripper oil prices to free market levels in 1975, were also considered in an effort to identify base trends within each region. In instances where individual events were not deemed to be significant in influencing current activity levels, a *trends continued* basis was used for the projection. Wells for each region were projected by distributing U.S. total wells (upper level) among the individual regions according to the projected distribution.

Within NPC Regions 2 and 3 through 8, which accounted for over 99.5 percent of 1978 wells drilled, wells, footage, average depth, and success rates were projected for each of five depth ranges (0-2,500 feet, 2,500-5,000 feet, 5,000-10,000 feet, and 10,000-15,000 feet). Wells by depth range were projected based on relative proportions of drilling in each depth range, considering past, present, and anticipated future influences. Average depths were projected for each depth range, primarily by extending historic trends. In some instances, where new developments have, or might in the future, change existing trends, the projected depths reflect a judgement of the impact of such a change. Depth bracket success rates were projected on the basis of continuing trends, with more recent years' results being given more weight than those of earlier years in the projection.

The results of these individual regional depth bracket projections, shown in Tables E-3 through E-12, were used directly with regional correlations of casing and tubing consumption and well depth for both dry holes and successful completions to determine oil country tubular goods demand. Footages were projected for each depth bracket by the multiplication of projected wells and average depths. These footages were then aggregated for all regions to determine depth bracket footage for these major drilling regions. An aggregate projection of wells and footage was made for Regions 1, 1-A, 2-A, and 8-A and added to the aggregated projections from the other regions to determine a total U.S. activity level.

Factors considered in making some of the individual regional drilling projections are discussed below.

Region 2

Activity in California, Oregon, and Washington onshore has been dominated by wells less than 2,500 feet deep. Most are oil wells used in the production of heavy oil by thermal techniques. In 1977, this activity declined due to difficulties in obtaining air emission permits for steam generation equipment. However, during 1978, activity rose to the previous 1976 level and continued growth was projected through 1981. All other depth ranges were projected to remain in about the same proportions in the 1979-81 period as they have maintained since 1975. Average depths in this region are expected to increase after stabilization of a surge in deep drilling in the early 1970's, attributable to the initial development of the Elk Hills field.

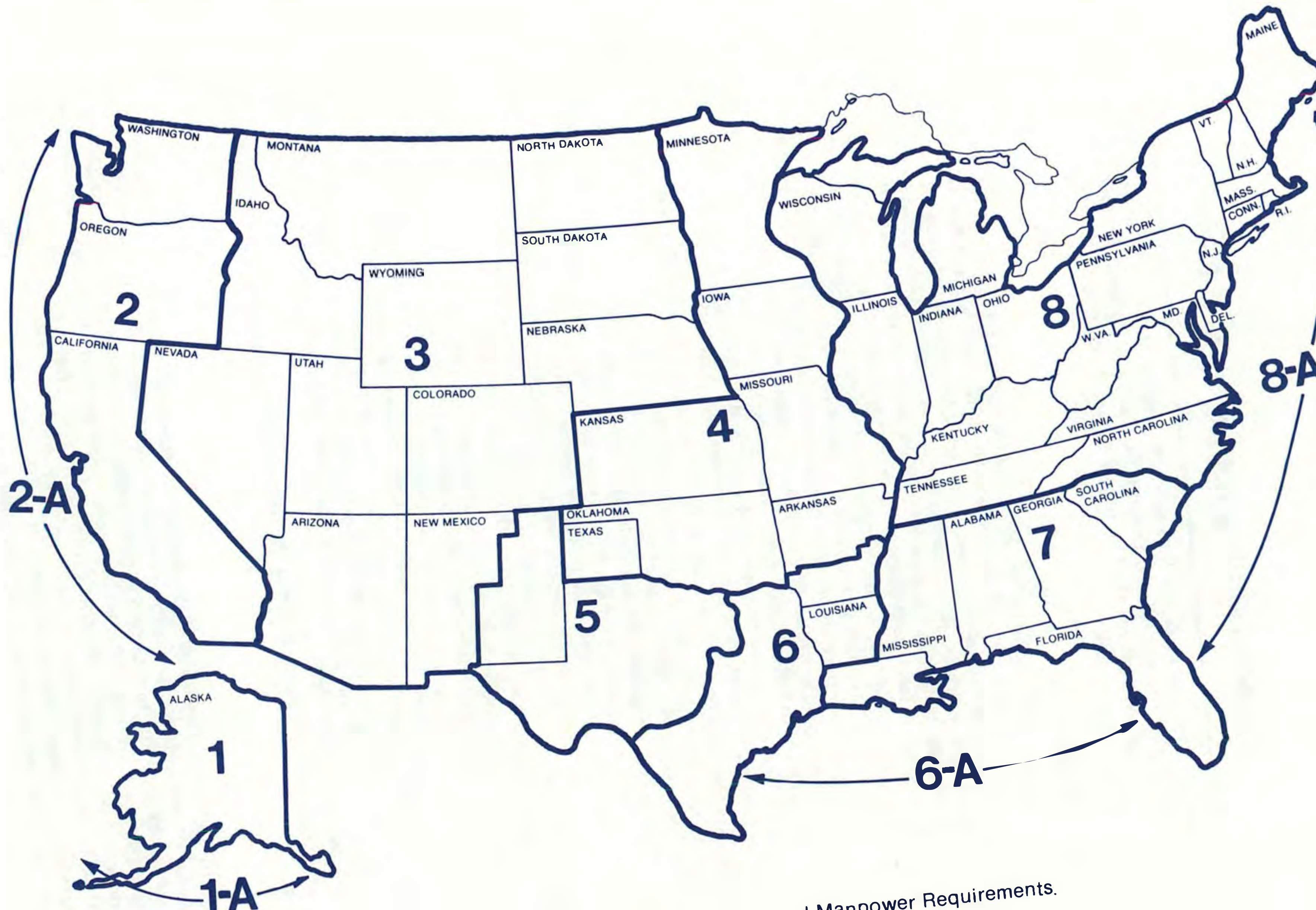


Figure E-1. Region Boundaries, NPC Materials and Manpower Requirements.

TABLE E-2

LISTING OF STATES OR PARTS OF STATES BY REGIONS

NPC Region	Description	State(s)
1	Alaska Onshore	
1-A	Alaska Offshore	
2	Pacific Coast	California, Oregon, Washington
2-A	Pacific Coast Offshore	
3	Rocky Mountain	Arizona, Colorado, Idaho, Montana, Nebraska, Nevada, New Mexico—West, North Dakota, South Dakota, Utah, Wyoming
4	Mid-Continent	Arkansas—North, Iowa, Kansas, Missouri, Minnesota, Oklahoma, Texas—RRC Dist. 10
5	West Texas—East New Mexico	New Mexico—East, Texas RRC Dists. 7B, 7C, 8, 8A, and 9
6	East Texas, South Arkansas, North Louisiana	Arkansas—South, Louisiana—North, Texas RRC Dists. 1-6
6-A	Gulf Coast Offshore	
7	Southeast and South Louisiana States	Alabama, Florida, Georgia, Louisiana—South, Mississippi, South Carolina
8	Northeast	Connecticut, Delaware, Illinois, Indiana, Kentucky, Maine, Maryland, Massachusetts, Michigan, New Hampshire, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, Tennessee, Vermont, Virginia, West Virginia, Wisconsin
8-A	Atlantic Offshore	

Region 3

Activity was projected to grow along historic trends in the Rocky Mountain and northern Midcontinent region. However, very shallow wells, where opportunities appear to be diminishing, are expected to decline. Considerable growth is expected in the 5,000-10,000 foot depth range, due to activities in the Overthrust Belt, the Williston Basin, and the Powder River, Wind River, and Green River Basins. The Rocky Mountain Overthrust Belt is also expected to contribute to significant growth at depths greater than 10,000 feet. Average depths in all depth brackets less than 15,000 feet have been changing only slightly during the past few years and are expected to continue along these trends. However, average depths greater than 15,000 feet have increased sharply as exploration in the region probes further into the deep Mississippian formations which generally lie below 15,000 feet.

Region 4

The primary growth in the number of wells drilled in Kansas, Oklahoma, Missouri, Texas Panhandle, northern Arkansas, Iowa, and Minnesota has occurred in the range of 2,500 to 10,000 feet. This activity appears to be a combination of infield drilling in mature fields and development of new discoveries. Although contributing somewhat to the growth in activity in the 5,000-10,000 foot category, the deep gas plays of the Anadarko Basin have been responsible for the growth in wells greater than 10,000 feet. Average depths for all ranges less than 15,000 feet are expected to increase slightly through 1981. Below 15,000 feet, average depths are expected to continue the declining trend which began in 1975, due to a near doubling of development activity, while exploratory drilling has declined.

Region 5

Growth in wells drilled in west Texas and eastern New Mexico, in all depth ranges, was projected to parallel historic trends with a favorable response to an upper level business environment. Led by exploration drilling and development of new oil discoveries, activity in the 2,500-5,000 foot range is expected to continue to grow more rapidly than other depth ranges through 1981. With the exception of wells greater than 15,000 feet, average depths in this region were projected to increase along the historical trend lines. Since 1972, the average depth of wells greater than 15,000 feet has generally declined. During this time, average depths have ranged from a high of almost 19,700 feet to a low of 17,900 feet in 1978. The projected average depth for 1979 through 1981 is expected to parallel the historic decline in depth at a level about equal to the average depth (18,500 feet) over the last five years.

Region 6

Because exploration success rates have increased by more than 100 percent from 17 percent in 1972 to 36 percent in 1977, the total number of wells drilled in the Texas Gulf Coast, southern Arkansas, and northern Louisiana area is expected to continue to increase more rapidly than the drilling in the United States as a whole. The growth in individual depth ranges was projected based upon historic trends, wells below 15,000 feet generally increasing, while those above 15,000 feet are decreasing in average depth. This decrease is attributed to the industry's limited success to date in exploring the deep Wilcox, Frio, and Miocene trends. This trend could be reversed by improved success in these areas or successful westward extension into Texas of Louisiana's Tuscaloosa Trend.

Region 6-A

The two major factors which dominate drilling activity in the Gulf of Mexico are opportunities for and the profitability of drilling on existing acreage, and the rate at which new acreage is leased. Under the upper level business environment, it was assumed that lease sales and other incentives would be improved to allow the growth of drilling activity to increase at about the same rate as the growth in U.S. drilling activity as a whole. Although some growth is projected for all depth ranges, recent trends indicate that significant growth may be expected at depths greater than 10,000 feet. Drilling in the 5,000-10,000 foot range is expected to decline due to the concurrent decrease in numbers of exploratory wells and success rates in this depth range. Average depths for all ranges were projected based on historic trends.

Region 7

Activity in south Louisiana, Mississippi, Alabama, Georgia, Florida, and South Carolina has been cyclical, influenced heavily by major new discoveries. Activity was high in the early 1970's following discovery of the Jay and Little Escambia Creek fields. In 1978, sharp increases are in large measure due to efforts to further explore and develop the Tuscaloosa Trend in Louisiana. However, since 1970, activity in this region has declined in terms of its proportionate share of U.S. total drilling. As a result of an assumed continuation of that trend, drilling activity measured in wells drilled beyond 1978 is expected to be relatively constant. The distribution of wells among the depth ranges was projected to follow very closely the distribution existing in 1978. Average depth in all depth ranges have been increasing, with those above 15,000 feet increasing most significantly as Tuscaloosa Trend activity and deep Smackover developments in Mississippi continue to become more significant.

Region 8

Activity in the northeastern United States, including the Appalachian, the Illinois, and the Michigan Basins has been largely the drilling of wells less than 5,000 feet deep. However, growth in the 5,000-10,000 foot depth range is likely with efforts to find and develop Oriskany sand gas deposits. Without information as to the extent of this growth, the wells were distributed among depth ranges on the basis of historic trends. Growth in drilling for the region as a whole was projected to follow the historic trend of increase established since 1973. Average depths for wells in this region in all depth ranges were projected on trendlines to increase through 1981.

TABLE E-3

WELLS DRILLED AND COMPLETED BY NPC REGION

NPC Region	1977	1978	1979	1980	1981
1	54	59	62	66	70
1-A	26	12	16	17	17
2	2,464	2,683	2,913	3,097	3,151
2-A	58	95	104	111	100
3	4,673	4,882	5,200	5,364	5,510
4	9,715	10,870	11,700	12,664	5,511
5	9,708	10,740	11,596	12,608	13,514
6	7,119	7,955	8,527	9,125	9,628
6-A	1,083	1,153	1,248	1,327	1,334
7	1,680	2,284	2,341	2,322	2,320
8	9,099	7,998	8,264	8,624	8,812
8-A	—	6	16	17	17
Total	**45,679**	**48,737**	**51,987**	**55,342**	**57,814**
Offshore Total	1,167	1,265	1,384	1,472	1,468

TABLE E-4

PROJECTED DRILLING ACTIVITY (Based on Regional Forecast and Upper Level of Activity Range)

NPC Region	Depth Ranges		1977	1978	1979	1980	1981
2, 3, 4, 5, 6, 6-A, 7, 8	< 2,500′	Wells	12,662	12,093	12,680	13,275	13,610
		Million Feet	18.5	18.0	19.3	20.4	21.2
		Avg Depth—feet	1,459	1,486	1,522	1,533	1,555
	2,500-5,000′	Wells	15,780	17,376	18,679	20,151	21,263
		Million Feet	58.0	63.8	69.0	74.5	78.5
		Avg Depth—feet	3,676	3,672	3,694	3,697	3,692
	5,000-10,000′	Wells	13,491	14,542	15,511	16,410	17,119
		Million Feet	93.3	101.5	108.2	114.9	120.1
		Avg Depth—feet	6,916	6,980	6,976	7,002	7,016
	10,000-15,000′	Wells	3,161	3,904	4,175	4,487	4,728
		Million Feet	36.7	45.9	49.3	53.0	55.8
		Avg Depth—feet	11,613	11,757	11,808	11,812	11,802
	> 15,000′	Wells	447	650	744	808	890
		Million Feet	7.7	10.9	12.7	13.7	15.1
		Avg Depth—feet	17,293	16,769	17,003	17,017	17,022
	Subtotal*	Wells	45,541	48,565	51,789	55,131	57,610
		Million Feet	214.2	240.1	258.5	276.6	290.8
		Avg Depth—feet	4,704	4,943	4,990	5,015	5,046
1, 1-A, 2-A, 8-A	Subtotal	Wells	138	172	198	211	204
		Million Feet	1.3	1.7	2.0	2.2	2.2
		Avg Depth—feet	9,420	9,880	10,100	10,425	10,780
	U.S. Total*	Wells	45,679	48,737	51,987	55,342	57,814
		Million Feet	215.5	241.8	260.5	278.8	293.0
		Avg Depth—feet	4,716	4,961	5,011	5,038	5,068

*Data may not add due to rounding.

TABLE E-5

NPC REGION 2
PROJECTED DRILLING ACTIVITY BY DEPTH RANGE
(Upper Level of Activity Range)

Depth Ranges		1977	1978	1979	1980	1981
<2,500′	Wells	1,634	1,876	1,995	2,118	2,156
	% of Regional Wells	66.3	69.9	68.5	68.4	68.4
	Avg Depth—feet	1,234	1,326	1,380	1,400	1,420
	Million Feet	2.0	2.5	2.8	3.0	3.1
	% Success	96.9	97.9	98.0	98.0	98.0
2,500-5,000′	Wells	506	405	504	533	542
	% of Regional Wells	20.5	15.1	17.3	17.2	17.2
	Avg Depth—feet	3,366	3,439	3,490	3,510	3,530
	Million Feet	1.7	1.4	1.8	1.9	1.9
	% Success	88.3	81.4	80.0	80.0	80.0
5,000-10,000′	Wells	275	303	335	356	362
	% of Regional Wells	11.2	11.3	11.5	11.5	11.5
	Avg Depth—feet	6,993	6,995	7,000	7,000	7,000
	Million Feet	1.9	2.1	2.3	2.5	2.5
	% Success	64.7	49.7	56.0	56.0	56.0
10,000-15,000′	Wells	47	99	76	87	88
	% of Regional Wells	1.9	3.7	2.6	2.8	2.8
	Avg Depth—feet	12,255	11,918	12,030	12,140	12,260
	Million Feet	0.6	1.2	0.9	1.1	1.1
	% Success	80.9	60.7	61.0	61.5	62.0
>15,000′	Wells	2	0	3	3	3
	% of Regional Wells	0.1	0	0.1	0.1	0.1
	Avg Depth—feet	16,400	—	18,000	18,000	18,000
	Million Feet	0.03	0	0.05	0.05	0.05
	% Success	50.0	—	40.0	40.0	40.0
Total*	Wells	2,464	2,683	2,913	3,097	3,151
	% of U.S. Wells	5.4	5.5	5.6	5.6	5.7
	Avg Depth—feet	2,537	2,674	2,685	2,724	2,744
	Million Feet	6.3	7.2	7.8	8.4	8.6

*Data may not add due to rounding.

TABLE E-6

NPC REGION 3
PROJECTED DRILLING ACTIVITY BY DEPTH RANGE
(Upper Level of Activity Range)

Depth Ranges		1977	1978	1979	1980	1981
<2,500′	Wells	644	767	692	665	634
	% of Regional Wells	13.8	15.7	13.3	12.4	11.5
	Avg Depth—feet	1,590	1,481	1,490	1,475	1,460
	Million Feet	1.0	1.1	1.0	1.0	0.9
	% Success	57.7	53.8	55.0	55.0	55.0
2,500-5,000′	Wells	1,352	1,289	1,425	1,464	1,499
	% of Regional Wells	28.9	26.4	27.4	27.3	27.2
	Avg Depth—feet	3,901	3,911	3,990	4,000	4,010
	Million Feet	5.3	5.0	5.7	5.9	6.0
	% Success	55.9	53.1	54.5	55.2	55.9
5,000-10,000′	Wells	2,320	2,358	2,532	2,623	2,705
	% of Regional Wells	49.6	48.3	48.7	48.9	49.1
	Avg Depth—feet	6,862	6,954	6,825	6,815	6,795
	Million Feet	15.9	16.4	17.3	17.9	18.4
	% Success	64.7	49.7	54.0	53.3	52.6
10,000-15,000′	Wells	327	439	515	574	634
	% of Regional Wells	7.0	9.0	9.9	10.7	11.5
	Avg Depth—feet	11,579	11,410	11,250	11,250	11,250
	Million Feet	3.8	5.0	5.8	6.5	7.1
	% Success	66.2	56.7	56.2	55.9	55.6
>15,000′	Wells	30	29	36	38	39
	% of Regional Wells	0.7	0.6	0.7	0.7	0.7
	Avg Depth—feet	16,173	16,383	16,490	16,590	16,690
	Million Feet	0.5	0.5	0.6	0.6	0.7
	% Success	57.1	58.8	58.3	57.9	57.6
Total*	Wells	4,673	4,882	5,200	5,364	5,511
	% of U.S. Wells	10.2	10.0	10.0	9.7	9.6
	Avg Depth—feet	5,669	5,750	5,846	5,947	6,007
	Million Feet	26.5	27.9	30.4	31.9	33.1

*Data may not add due to rounding.

TABLE E-7

NPC REGION 4
PROJECTED DRILLING ACTIVITY BY DEPTH RANGE
(Upper Level of Activity Range)

Depth Ranges		1977	1978	1979	1980	1981
<2,500′	Wells	2,546	2,282	2,399	2,533	2,601
	% of Regional Wells	26.2	21.0	20.5	20.0	19.5
	Avg Depth—feet	1,436	1,552	1,590	1,620	1,660
	Million Feet	3.7	3.5	3.8	4.1	4.3
	% Success	72.0	71.8	72.0	72.0	72.0
2,500-5,000′	Wells	4,201	5,077	5,511	5,990	6,283
	% of Regional Wells	43.2	46.7	47.1	47.3	47.1
	Avg Depth—Feet	3,657	3,673	3,650	3,650	3,650
	Million Feet	15.4	18.6	20.1	21.9	22.9
	% Success	57.6	58.5	57.8	58.8	58.9
5,000-10,000′	Wells	2,353	2,730	2,913	3,166	3,375
	Avg Depth—feet	7,928	7,008	7,000	6,990	6,980
	Million Feet	16.5	19.1	20.4	22.1	23.6
	% Success	69.0	66.4	63.5	63.7	64.0
10,000-15,000′	Wells	541	651	737	823	907
	% of Regional Wells	5.6	6.0	6.3	6.5	6.8
	Avg Depth—feet	11,360	11,589	11,690	11,780	11,850
	Million Feet	6.1	7.5	8.6	9.7	10.7
	% Success	61.5	62.1	62.2	62.9	63.2
>15,000′	Wells	74	130	140	152	174
	% of Regional Wells	0.8	1.2	1.2	1.2	1.3
	Avg Depth—feet	16,789	16,328	16,300	16,070	15,830
	Million Feet	1.2	2.1	2.3	2.4	2.8
	% Success	73.3	65.9	67.1	67.5	67.9
Total*	Wells	9,715	10,870	11,700	12,664	13,340
	Avg Depth—feet	4,429	4,691	4,719	4,756	4,821
	Million Feet	42.9	51.0	55.2	60.2	64.3

*Data may not add due to rounding.

TABLE E-8

NPC REGION 5
PROJECTED DRILLING ACTIVITY BY DEPTH RANGE
(Upper Level of Activity Range)

Depth Ranges		1977	1978	1979	1980	1981
<2,500′	Wells	2,397	2,223	2,412	2,622	2,797
	% of Regional Wells	24.7	20.7	20.8	20.8	20.7
	Avg Depth—feet	1,409	1,397	1,410	1,450	1,490
	Million Feet	3.4	3.1	3.4	3.8	4.2
	% Success	68.1	67.2	67.5	67.5	67.5
2,500-5,000′	Wells	3,573	4,178	4,546	5,005	5,433
	% of Regional Wells	36.8	38.9	39.2	39.7	40.2
	Avg Depth—feet	3,772	3,834	3,830	3,850	3,870
	Million Feet	13.5	16.0	17.4	19.3	21.0
	% Success	71.7	69.1	70.0	70.0	70.0
5,000-10,000′	Wells	3,216	3,802	4,035	4,325	4,581
	% of Regional Wells	33.1	35.4	34.8	34.3	33.9
	Avg Depth—feet	6,618	6,658	6,690	6,720	6,760
	Million Feet	21.3	25.3	27.0	29.1	31.0
	% Success	75.0	74.7	74.0	73.7	73.2
10,000-15,000′	Wells	459	451	487	517	541
	% of Regional Wells	4.7	4.2	4.2	4.1	4.0
	Avg Depth—feet	11,410	11,708	11,810	11,910	12,000
	Million Feet	5.2	5.3	5.8	6.2	6.5
	% Success	61.4	62.2	62.0	62.0	62.0
>15,000′	Wells	63	86	116	139	162
	% of Regional Wells	0.6	0.8	1.0	1.1	1.2
	Avg Depth—feet	18,603	17,833	18,500	18,450	18,390
	Million Feet	1.2	1.5	2.1	2.6	3.0
	% Success	66.5	60.4	66.0	65.5	65.0
Total*	Wells	9,708	10,740	11,596	12,608	13,514
	% of U.S. Wells	21.2	22.0	22.3	22.8	23.3
	Avg Depth—feet	4,589	4,775	4,803	4,838	4,862
	Million Feet	44.6	51.3	55.7	61.0	65.7

*Data may not add due to rounding.

TABLE E-9

NPC REGION 6
PROJECTED DRILLING ACTIVITY BY DEPTH RANGE
(Upper Level of Activity Range)

Depth Ranges		1977	1978	1979	1980	1981
< 2,500′	Wells	1,605	1,782	1,868	1,989	2,089
	% of Regional Wells	22.5	22.4	21.9	21.8	21.7
	Avg Depth—feet	1,790	1,688	1,700	1,700	1,700
	Million Feet	2.8	3.0	3.2	3.4	3.6
	% Success	78.4	72.9	74.0	73.2	72.8
2,500-5,000′	Wells	1,621	2,013	2,200	2,354	2,484
	% of Regional Wells	22.8	25.3	25.8	25.8	25.8
	Avg Depth—feet	3,505	3,500	3,480	3,450	3,420
	Million Feet	5.7	7.0	7.7	8.1	8.5
	% Success	53.2	52.9	53.3	53.6	53.9
5,000-10,000′	Wells	3,150	3,285	3,496	3,714	3,890
	% of Regional Wells	44.2	41.3	41.0	40.7	40.4
	Avg Depth—feet	7,276	7,342	7,350	7,400	7,460
	Million Feet	22.9	24.1	25.7	27.5	29.0
	% Success	62.1	57.6	55.5	54.6	52.4
10,000-15,000′	Wells	721	835	912	1,013	1,098
	% of Regional Wells	10.1	10.5	10.7	11.1	11.4
	Avg Depth—feet	11,378	11,469	11,490	11,520	11,550
	Million Feet	8.2	9.6	10.5	11.7	12.7
	% Success	62.8	55.4	56.2	57.0	57.8
> 15,000′	Wells	62	40	51	55	67
	% of Regional Wells	0.3	0.5	0.6	0.6	0.7
	Avg Depth—feet	16,141	15,503	15,630	15,470	15,300
	Million Feet	0.4	0.6	0.8	0.9	1.0
	% Success	52.4	42.3	49.0	49.9	50.5
Total*	Wells	7,119	7,955	8,527	9,125	9,628
	% of U.S. Wells	15.6	16.3	16.4	16.5	16.6
	Avg Depth—feet	5,624	5,581	5,605	5,645	5,689
	Million Feet	40.0	44.4	47.8	51.5	54.8

*Data may not add due to rounding.

TABLE E-10

NPC REGION 6-A
PROJECTED DRILLING ACTIVITY BY DEPTH RANGE
(Upper Level of Activity Range)

Depth Ranges		1977	1978	1979	1980	1981
< 2,500′	Wells	5	12	10	12	13
	% of Regional Wells	0.5	1.0	0.8	0.9	1.0
	Avg Depth—feet	1,140	1,243	1,250	1,250	1,250
	Million Feet	0.006	0.01	0.01	0.01	0.02
	% Success	40.0	0	0	0	0
2,500-5,000′	Wells	41	52	62	74	83
	% of Regional Wells	3.8	4.5	5.0	5.6	6.2
	Avg Depth—feet	4,171	4,000	4,180	4,180	4,180
	Million Feet	0.2	0.2	0.3	0.3	0.3
	% Success	48.8	40.6	45.0	45.0	45.0
5,000-10,000′	Wells	558	540	565	569	540
	% of Regional Wells	51.5	46.9	45.3	42.9	40.5
	Avg Depth—feet	8,036	8,003	8,000	8,000	8,000
	Million Feet	4.5	4.3	4.5	4.6	4.3
	% Success	41.8	39.9	38.5	37.5	36.5
10,000-15,000′	Wells	438	479	527	567	574
	% of Regional Wells	40.4	41.6	42.2	42.7	43.0
	Avg Depth—feet	11,879	11,993	12,020	12,080	12,080
	Million Feet	5.2	5.7	6.3	6.8	6.9
	% Success	45.0	43.3	42.5	41.6	40.9
> 15,000′	Wells	41	70	84	105	124
	% of Regional Wells	3.8	6.1	6.7	7.9	9.3
	Avg Depth—feet	16,049	16,477	16,350	16,365	16,380
	Million Feet	0.7	1.2	1.4	1.7	2.0
	% Success	34.1	54.5	41.3	39.0	37.0
Total*	Wells	1,083	1,153	1,248	1,327	1,334
	% of U.S. Wells	2.4	2.4	2.4	2.4	2.3
	Avg Depth—Feet	9,715	9,937	10,011	10,128	10,229
	Million Feet	10.5	11.5	12.5	13.4	13.6

*Data may not add due to rounding.

TABLE E-11

NPC REGION 7
PROJECTED DRILLING ACTIVITY BY DEPTH RANGE
(Upper Level of Activity Range)

Depth Ranges		1977	1978	1979	1980	1981
< 2,500′	Wells	43	32	30	23	23
	% of Regional Wells	2.6	1.4	1.3	1.0	1.0
	Avg Depth—feet	1,581	1,785	1,700	1,700	1,700
	Million Feet	0.07	0.06	0.05	0.04	0.04
	% Success	34.9	50.0	55.0	55.0	55.0
2,500-5,000′	Wells	180	267	289	297	311
	% of Regional Wells	10.7	11.7	12.3	12.8	13.4
	Avg Depth—feet	3,728	3,620	3,770	3,770	3,770
	Million Feet	0.7	1.0	1.1	1.1	1.2
	% Success	57.2	46.4	57.5	57.5	57.5
5,000-10,000′	Wells	619	740	800	794	793
	% of Regional Wells	36.8	32.4	34.2	34.2	34.2
	Avg Depth—feet	7,320	7,628	7,650	7,650	7,650
	Million Feet	4.5	5.6	6.1	6.1	6.1
	% Success	38.6	37.2	37.5	37.0	36.5
10,000-15,000′	Wells	627	950	913	897	877
	% of Regional Wells	37.3	41.6	39.0	38.6	37.8
	Avg Depth—feet	12,089	12,149	12,130	12,170	12,200
	Million Feet	7.6	11.5	11.1	10.9	10.7
	% Success	43.7	41.5	41.5	41.5	41.5
> 15,000′	Wells	211	295	309	311	316
	% of Regional Wells	12.6	12.9	13.2	13.4	13.6
	Avg Depth—feet	17,204	17,065	17,300	17,420	17,540
	Million Feet	3.6	5.0	5.3	5.4	5.5
	% Success	47.9	44.6	41.0	40.0	40.0
Total *	Wells	1,680	2,284	2,341	2,322	2,320
	% of U.S. Wells	3.7	4.7	4.5	4.2	4.0
	Avg Depth—feet	9,810	10,180	10,116	10,148	10,136
	Million Feet	16.5	23.2	23.7	23.6	23.5

*Data may not add due to rounding.

TABLE E-12

NPC REGION 8
PROJECTED DRILLING ACTIVITY BY DEPTH RANGE
(Upper Level of Activity Range)

Depth Ranges		1977	1978	1979	1980	1981
<2,500′	Wells	3,788	3,119	3,274	3,313	3,297
	% of Regional Wells	41.6	39.0	39.6	38.4	37.4
	Avg Depth—feet	1,442	1,459	1,480	1,500	1,520
	Million Feet	5.5	4.6	4.9	5.0	5.0
	% Success	71.8	68.4	70.0	70.0	70.0
2,500-5,000′	Wells	4,306	4,095	4,142	4,434	4,628
	% of Regional Wells	47.3	51.2	50.4	51.4	52.5
	Avg Depth—feet	3,609	3,559	3,600	3,600	3,600
	Million Feet	15.5	14.6	14.9	16.0	16.7
	% Success	80.8	76.1	81.0	81.0	81.0
5,000-10,000′	Wells	1,000	784	835	863	873
	% of Regional Wells	11.0	9.8	10.1	10.0	9.9
	Avg. Depth—feet	5,816	5,871	5,900	5,930	5,960
	Million Feet	5.8	4.6	4.9	5.1	5.2
	% Success	77.5	66.5	68.0	66.0	63.5
10,000-15,000′	Wells	1	0	8	9	9
	% of Regional Wells	0.1	—	0.1	0.1	0.1
	Avg Depth—feet	10,600	—	12,220	12,270	12,320
	Million Feet	0.01	—	0.1	0.1	0.1
	% Success	—	—	30.0	30.0	30.0
>15,000′	Wells	4	0	5	5	5
	% of Regional Wells	0.04	—	0.1	0.1	0.1
	Avg Depth—feet	19,475	—	19,800	19,800	19,800
	Million Feet	0.1	—	0.1	0.1	0.1
	% Success	—	—	29.4	29.4	29.4
Total *	Wells	9,099	7,998	8,264	8,624	8,812
	% of U.S. Wells	19.9	16.4	15.9	15.6	15.2
	Avg Depth—feet	2,957	2,976	3,012	3,032	3,072
	Million Feet	26.9	23.8	24.9	26.2	27.1

*Data may not add due to rounding.

Projection of Exploration Drilling

Background

Exploration drilling is a high risk investment activity. Table E-13 shows that statistically, only about one of every four wells drilled since 1974 was classified as successful, meaning producible hydrocarbons were encountered. However, not all of these are economically successful discoveries. Table E-14 shows that improved success was primarily due to more gas discoveries. Prior to the real price increases for gas and oil in 1974, only one well in six was completed for production. Increased prices have significantly contributed to the increased success, in that smaller accumulations are now commercial. The American Association of Petroleum Geologist's analysis of the size of new discoveries, shown in Figure E-2, indicates that increased drilling has not caused a significant change in the fraction of new fields discovered with reserves greater than one million barrels of oil equivalent hydrocarbons. There has been a dramatic growth in new field discoveries with reserves less than one million barrels oil equivalent.

Higher prices have resulted in proportionately more development drilling than exploration drilling. The percentage of total wells and footage drilled for exploration, shown in Figure E-3, was increasing in the late 1960's, prior to significant price increases. With the initial price increases primarily for free market intrastate gas in 1971, the rate of growth slowed as gas discoveries which may have been uneconomic became developable. In 1974, both gas and oil prices increased substantially, and the proportions of footage and wells drilled for exploration declined further because of increasing emphasis on relatively lower risk infield development drilling. Figure E-4 shows that while exploration drilling became proportionately lower, the absolute number of wells drilled grew by more than 50 percent, from 7,000 wells in 1971 to about 10,600 in 1978, a compound growth rate of 6.3 percent per year. Annual growth in completions for oil was 7.9 percent per year, and for gas it was 19.9 percent per year. Dry holes grew at the rate of 4.3 percent per year. Growth rates for exploration footage (Figure E-5) have been 8.7 percent per year for oil, 17.0 percent per year for gas, 4.2 percent per year for dry holes, and 6.2 percent per year for total exploration footage.

The average depth of exploration wells (Figure E-6) which were completed as gas wells has declined sharply since improvements in gas prices began. This trend and the rise in success factors (discussed previously) suggest that a significant number of these discoveries may have been in areas where small gas deposits were known to exist, but were not developed because they were uneconomic at previous prices. As opportunities of this type diminish, it is likely that the average depth of gas wells will increase, and success ratios will decrease. Improving economics of deep gas production brought about by price increases adds to the prospects for increasing average depths.

A similar discussion probably also applies to oil wells, but the effect of shallow activity has not been as dramatic.

Preliminary 1978 data in Figure E-6 show an increase in average depth in all exploration wells. This could be an indication that the inventory of shallow oil and gas deposits may be playing out at the current level of profit margins. This theory is reinforced by the gradual increase since 1974 in the average depth of wells less than 5,000 feet, while the number of these wells drilled each year has increased. Recently declining success rates and increasing average depths of oil wells may also be associated with diminishing opportunities in shallow, known areas. It is too early to tell whether the slight declines in success ratios for gas wells in 1978 are indicative of a lasting trend toward more historical success rates for the current price and cost relationships.

TABLE E-13

SUCCESS RATIOS FOR U.S. EXPLORATION *

	Footage			
	Oil	**Gas**	**Total Productive**	**Dry**
1970	0.108	0.084	0.192	0.808
1971	0.091	0.085	0.176	0.824
1972	0.089	0.107	0.196	0.804
1973	0.088	0.153	0.241	0.759
1974	0.098	0.149	0.248	0.752
1975	0.106	0.154	0.259	0.741
1976	0.120	0.171	0.281	0.709
1977	0.117	0.171	0.288	0.712
1978 (preliminary)	0.107	0.169	0.276	0.724
	Wells			
1970	0.102	0.065	0.167	0.833
1971	0.092	0.066	0.158	0.842
1972	0.090	0.088	0.178	0.822
1973	0.083	0.139	0.222	0.778
1974	0.096	0.134	0.230	0.770
1975	0.104	0.133	0.237	0.763
1976	0.117	0.145	0.262	0.738
1977	0.115	0.150	0.265	0.735
1978 (preliminary)	0.104	0.149	0.253	0.747

* Calculated from API *Drilling Statistics* for wells reported as having been completed for production.

API drilling statistics show that inland lower 48 activity has contributed essentially all of the increase in exploration drilling. Offshore exploration drilling has been relatively constant in the range of 209 to 334 wells (Figure E-7) and 2.2 to 3.1 million feet of hole per year since 1971. However, success ratios for offshore exploration have declined sharply as shown in Table E-15. This reflects a combination of diminishing returns in the western Gulf of Mexico, increased delineation drilling for discoveries in deeper waters and, to a lesser extent, disappointing results in major new frontier areas (MAFLA, Gulf of Alaska, California's Outer Banks, and mid-Atlantic), and limited access to new high potential acreage outside the Gulf of Mexico due to slow rates of leasing. Table E-16 shows 1971-1977 average leasing rates of about 1.0 million acres per year, most of which has been in the western Gulf of Mexico.

Upper Level Exploration Drilling Projection

Significant real oil price increases, offset somewhat by regulation of intrastate gas, are expected to provide incentive for growth of exploration drilling. However, it is expected that lower

TABLE E-14

U.S. OIL AND GAS PRICES

	Average Natural Gas Realizations *		
	Average Wellhead Realization (¢/MCF)	Price Index (1967=100)	Crude Oil Price Index † (1967=100)
1960	14.0	88	
1967	16.0	100	100
1968	16.4	103	101
1969	16.7	104	105
1970	17.1	107	106
1971	18.2	114	113
1972	18.6	116	114
1973	21.6	135	126
1974	30.4	190	212
1975	44.5	278	246
1976	58.0	363	254
1977	79.0	494	299

* From Department of Energy, Energy Information Administration, *Energy Data Report*, Natural Gas, Annual (1976-1977). Prior to 1976, U.S. Bureau of Mines, *Mineral Industry Surveys*, Natural Gas, Annual.
† From U.S. Bureau of Labor Statistics.

risk development drilling activities will respond somewhat faster than exploration. Because price increases assumed for the upper level case are considerably smaller than the 250 percent increase (new oil) realized in 1974[1] growth of exploration drilling (wells) is expected to be somewhat less than the 6.3 percent per year (1974-1977) historical rate. The projected exploration activity shown in Table E-17 represents a 4.5 percent per year compound growth from 1978 through 1990.

Development drilling is projected to grow at 6.2 percent per year from 1978 through 1981, while assumed improvements in lower tier prices are expected to stimulate infield drilling in fields where it was previously unattractive. However, because of high levels of infield drilling in the last five years, future increases are expected to be less significant and of shorter duration than in the past. As remaining infield opportunities in maturing fields are consumed, growth in development drilling in the late 1980's is expected to be primarily associated with enhanced oil recovery projects. Because future discoveries at higher price levels are likely to be predominantly small (less than one million barrels oil equivalent), relatively fewer development wells will be required. As a result, the proportionate number of exploration wells drilled may increase. Also contributing to this proportionate growth in exploration could be activities in high cost new frontier areas (offshore and in the Arctic), where it is likely that more exploration wells will be required to better define reserves to reduce the risk for development investments, and where fewer, more prolific development wells will be justifiable for economic development of reserves.

[1] $3.99 per barrel in August 1973; 1974 average new oil price—$9.99 per barrel.

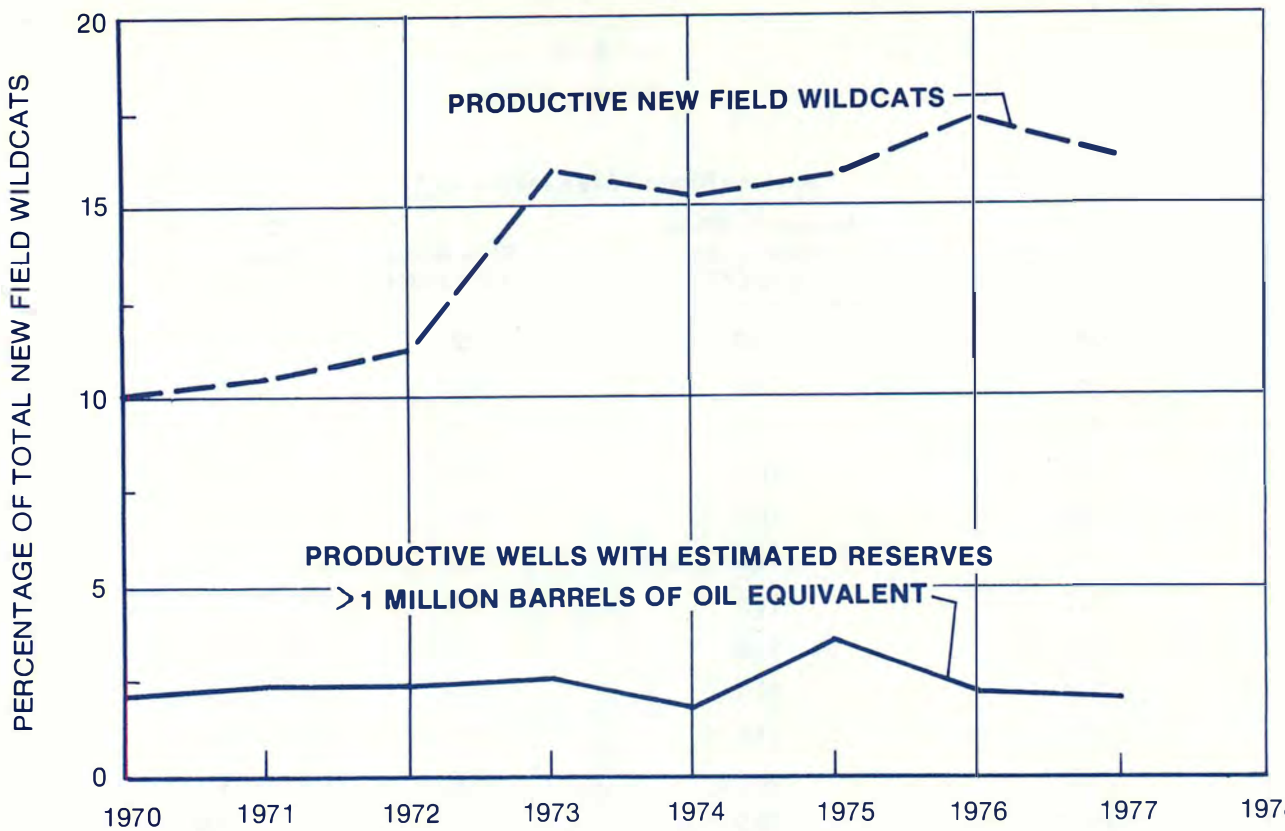


Figure E-2. AAPG New Field Wildcats.

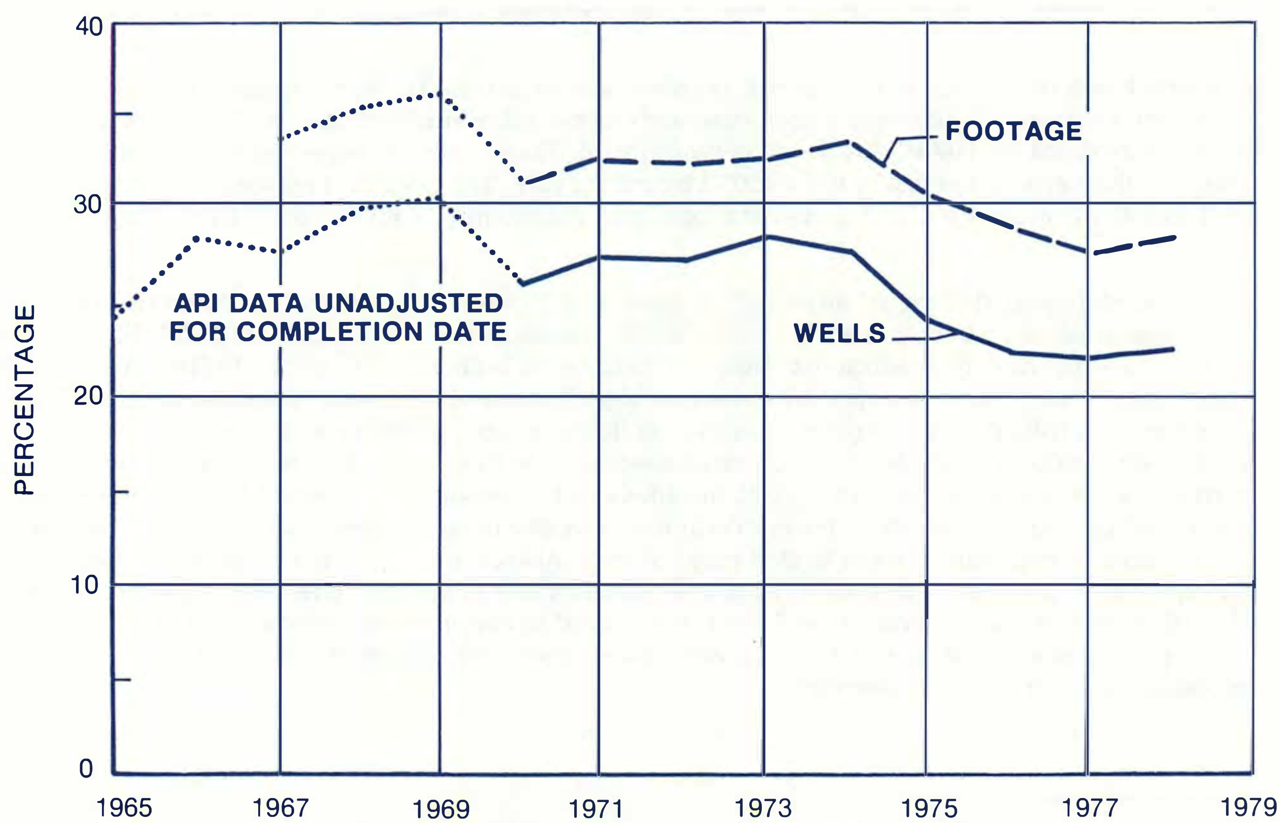


Figure E-3. U.S. Exploration Drilling as Percent of Total Drilling Activity.

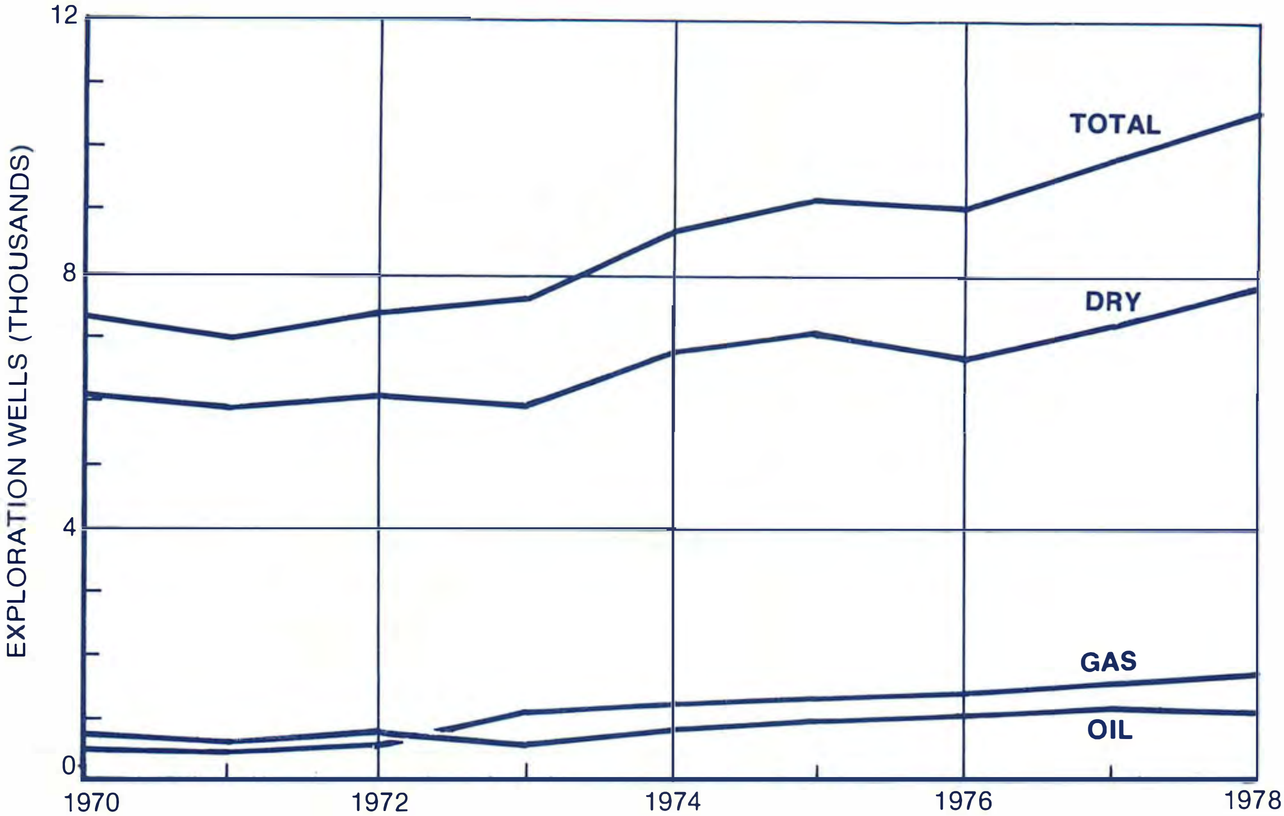


Figure E-4. U.S. Exploration Wells.

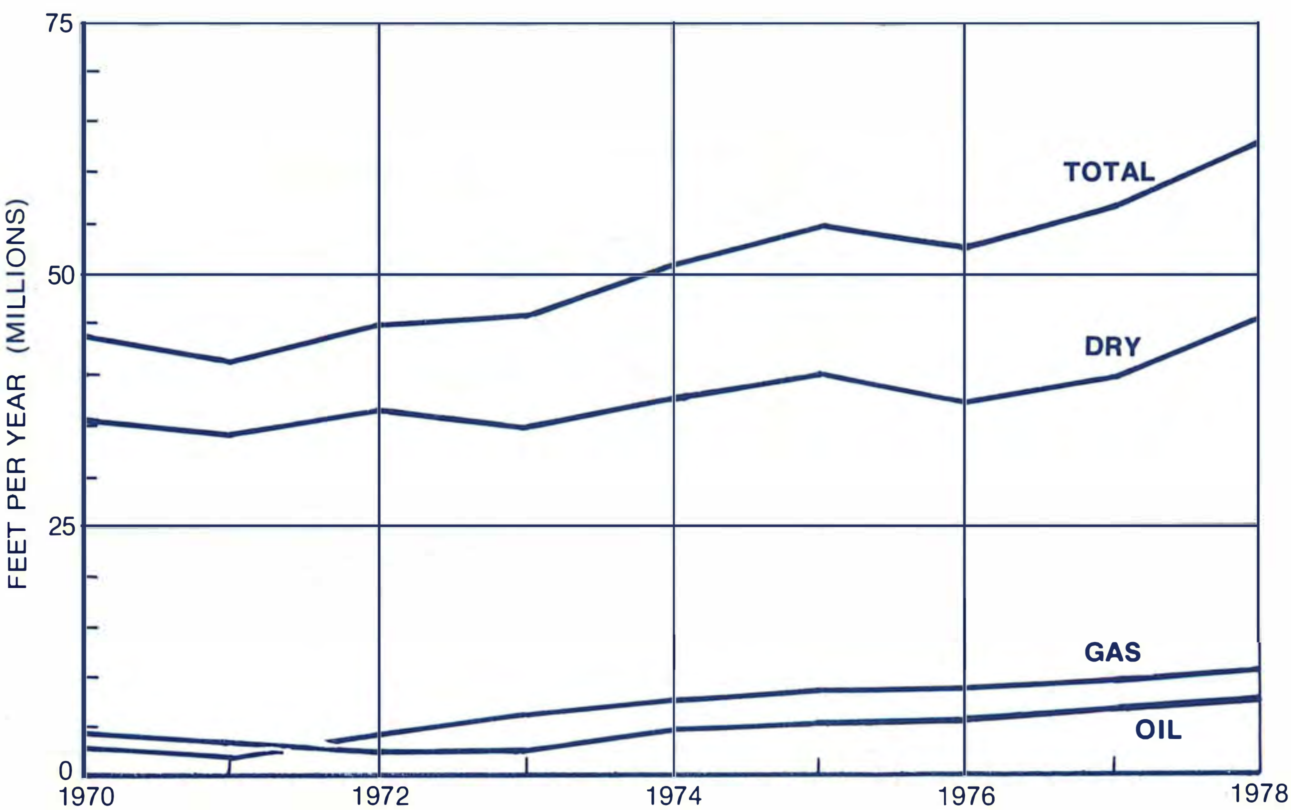


Figure E-5. U.S. Exploration Footage.

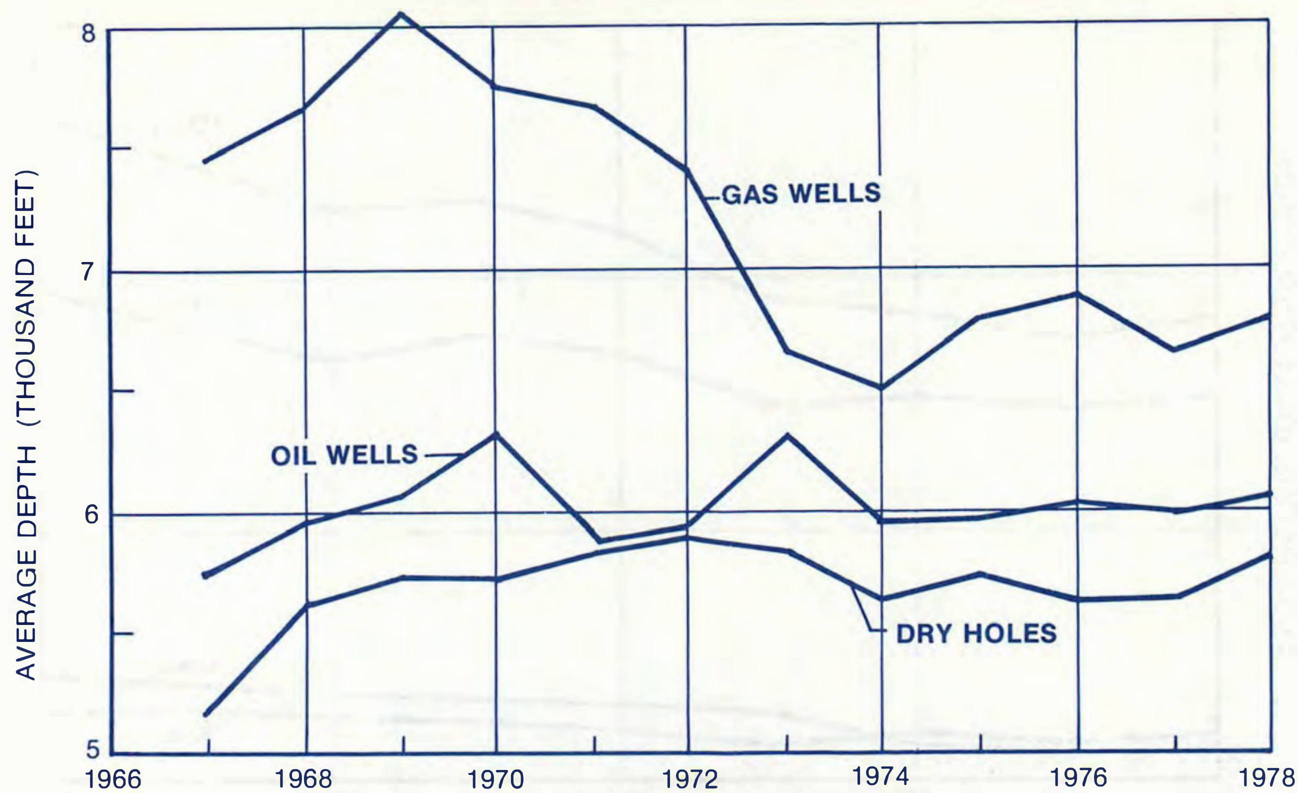


Figure E-6. U.S. Exploration Wells — Average Depth.

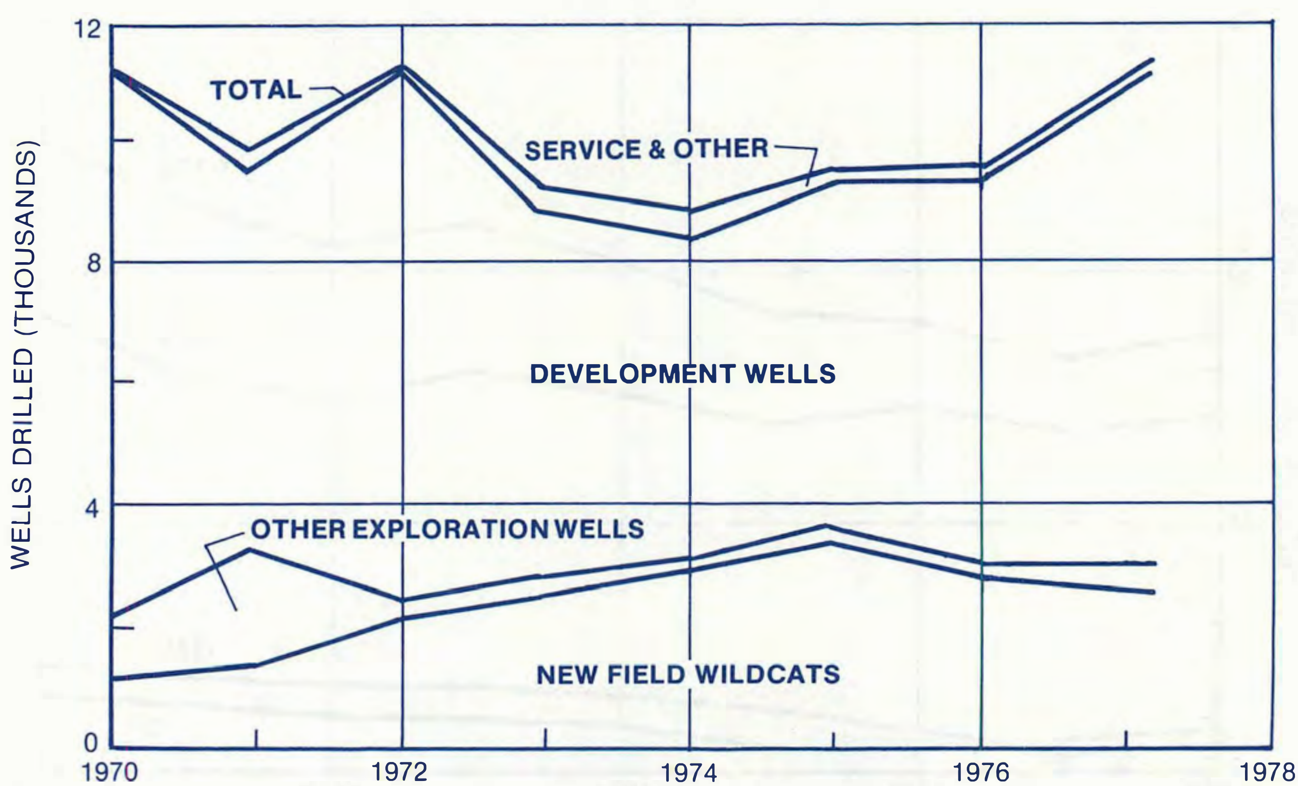


Figure E-7. U.S. Offshore Drilling Activity.

TABLE E-15

SUCCESS RATIOS FOR OFFSHORE EXPLORATION WELLS *

	Successful Fraction	Dry Fraction
1970	0.167	0.833
1971	0.128	0.872
1972	0.092	0.908
1973	0.067	0.933
1974	0.058	0.942
1975	0.033	0.967
1976	0.077	0.923
1977	0.057	0.943

* Calculated from API *Drilling Statistics.*

TABLE E-16

OCS LEASING 1970-1977 (Thousand Acres per Year)

	Gulf of Mexico	Other	Total
1970	599	0	599
1971	37	0	37
1972	826	0	826
1973	1,033	0	1,033
1974	1,760	0	1,760
1975	1,370	310	1,680
1976	339	938	1,277
1977	605	395	1,100
1971-77 Avg	821	292	1,039

TABLE E-17

PROJECTED EXPLORATION AND DEVELOPMENT WELLS
UPPER LEVEL CASE
(Thousand Wells)

	Total Wells (upper limit)	Service * and Other Wells	Exploration Wells	Development Wells
1977 (actual)	46.5	1.4	10.0	35.1
1978 (preliminary)	48.5	2.0	10.6	35.6
1979	52.0	2.0	11.5	38.5
1980	55.3	2.0	12.3	41.0
1981	58.0	2.0	13.0	43.0
1985	64.6	2.0	14.9	47.7
1990	75.4	2.0	17.9	55.3

* Estimate 1978 and future based on 1974-1977 average of 2,000 wells per year; determined from API *Drilling Statistics.*

APPENDIX F

Geological and Geophysical Services

Geological and Geophysical Services

Wireline Services

The wireline industry (well logging and perforating) is made up of six major service companies and another 50 to 80 smaller operators with one to ten trucks each. Two of the six major companies work almost exclusively in cased hole, while the other four work both in open hole and cased hole. There is one major supplier for the cased hole operators. The open hole service companies are completely self-sufficient; they design, build, and use their own tools and hardware, including trucks. U.S. companies dominate the worldwide wireline market with no significant foreign suppliers competing except for one multinational. The communist wireline service is supported by Russian technology which is much less sophisticated. The third world wireline technology is dominated by U.S. technology. The four major companies that work both in open hole and cased hole all operate worldwide.

Wireline services are performed with truck-mounted equipment of two types: well logging and perforating units. The demand for these services in the U.S. correlates closely with the active rig count. Over the past several years, the fleet has been maintained at a ratio of about 4.2 active rigs per logging unit and 2.3 rigs per perforating unit. It is expected that as the average well depth increases in the future, the ratio of active rigs served per logging unit will increase to 4.5, and rigs per perforating unit will go up to 2.5.

The projected demands, based on the Outlook upper level possible drilling activity and historical rig/unit ratios, are shown in Table F-1, column 2 for logging units and column 4 for perforating units. Through 1981, these projections are quite close to wireline services industry projections shown in columns 3 and 5 of Table F-1. The upper level possible demands are considerably above the wireline services industry projections for 1985 and 1989. This is because the Outlook upper level projection assumes that rig drilling performance will remain constant at 105,000 feet per year, while the wireline services industry projects an increase to 111,000 feet in 1980, 120,000 in 1985, and 125,000 feet in 1990. Since the projected wireline unit demand is directly proportional to the number of active rigs, the demand projected as probable by the wireline services industry flattens after 1985.

The projected unit supply is based on the demonstrated ability of the industry to add 93 logging units and 165 perforating units to the fleet in the year 1977. The number of logging units projected to be in service are shown in Table F-1, column 6; perforating units are shown in column 7. Both are indicated as sufficient to supply either the wireline services industry projections or the Outlook upper level demand projections out to 1990.

Should the demand be greater than the projected capacity, the 1977 unit growth rate could be increased in response. Surge growth is normally accommodated within the industry by rehabilitating the retirable equipment and extending its useful life. This expansion capacity is built into the business, as amortization life is normally 4 to 6 years. Therefore, no significant constraints are apparent in the gross amount of equipment available to accomodate increases in drilling activity.

Constraints in the development of new wireline services technology relate to the economics of the industry. The availability of discretionary income to fund research and development of the sensor, specialized electronics, cable technology, and new data processing applications will control the rate of technological growth. The environmental requirements for downhole instruments require a 200° C to 250° C standard for electronics, which is not yet available. Also to be developed are high data rate telemetry systems and pressure adaptive systems. The development of new measurements and their application to a more refined evaluation of a suite of logs will have a significant impact on the ability to improve well completion and oil recovery efficiencies. The recent introduction of computer-assisted systems promises to open many areas for potentially higher recovery efficiencies.

TABLE F-1
WIRELINE SERVICE UNITS

	Active Rigs	Demand: Logging Units		Demand: Perforating Units		Supply: Logging Units	Supply: Logging Rigs Per Unit	Supply: Perforating Units	Supply: Perforating Rigs Per Unit
Historical									
1973	1,194					314	3.8	561	2.1
1974	1,472					387	3.8	691	2.1
1975	1,660					394	4.2	703	2.4
1976	1,658					395	4.2	705	2.4
1977	2,001					488	4.1	870	2.3
1978	2,259					518	4.4	925	2.4
	(1)	(2)	(3)	(4)	(5)	(6)		(7)	
Projected									
1979	2,486	552	552	994	985	611		1,090	
1980	2,657	590	580	1,063	1,035	704		1,255	
1981	2,790	620	617	1,116	1,101	797		1,420	
1985	3,362	747	704	1,345	1,257	1,169		2,080	
1989	3,981	885	690	1,592	1,200	1,541		2,740	
1990	4,143	921		1,657		1,634		2,905	

Column:
- (1) Outlook upper level possible.
- (2) 4.5 active rigs per logging unit.
- (3) Wireline industry projected.
- (4) 2.5 active rigs per perforating unit.
- (5) Wireline industry projected.
- (6) 93 logging units added per year.
- (7) 165 wireline units added per year.

APPENDIX G

Drilling Equipment Survey

Exhibit G-1

NATIONAL PETROLEUM COUNCIL
STUDY ON MATERIALS AND MANPOWER REQUIREMENTS

DRILLING EQUIPMENT TASK GROUP

SURVEY QUESTIONNAIRE FOR DRILLING RIGS

Part I

In the tables below, please estimate the following information for each year, 1978-1981:

(1) Your anticipated maximum **worldwide production capacity** in units (based on a 24-hour day, 5-day week).

(2) The **percentage utilization** you expect for this capacity.

(3) The approximate percentage of your worldwide capacity dedicated to: (a) U.S. markets, (b) foreign markets.

Since we are grouping some sizes and depth ratings together, please base the estimates on your **typical product mix.**

WORLDWIDE CAPACITY
(Units and % Utilization)

Rig Production by Depth Range	1978 Actual		1979		1980		1981	
	Capacity	% Utilizn.	Capacity	% Utilizn.	Capacity	% Utilizn.	Capacity	% Utilizn.
3,000-5,000 ft.	127	85.0	168	81.0	160	81.9	170	85.3
6,000-9,000 ft.	113	86.7	151	87.7	157	81.5	164	82.0
10,000-12,000 ft.	78	84.0	136	87.5	132	85.6	125	80.8
13,000-15,000 ft.	60	91.7	103	95.1	95	88.4	103	92.2
16,000 ft. & over	112	92.9	172	89.5	162	85.8	144	93.1
Total Mfg. Capacity	490	87.9	730	87.6	706	84.3	706	86.3

WORLDWIDE CAPACITY DEDICATED TO U.S. AND FOREIGN MARKETS
(Percentage)

Rig Capacity by Depth Range	1978 Actual		1979		1980		1981	
	U.S.	Foreign	U.S.	Foreign	U.S.	Foreign	U.S.	Foreign
3,000-5,000 ft.	82.7	17.3	81.0	19.0	80.9	19.1	98.8	21.2
6,000-9,000 ft.	77.0	23.0	71.9	28.1	73.2	26.8	73.8	26.2
10,000-12,000 ft.	78.2	21.8	77.9	22.1	75.8	24.2	72.0	28.0
13,000-15,000 ft.	76.7	23.3	65.0	35.0	60.0	40.0	57.3	42.7
16,000 ft. & over	64.3	35.7	61.6	38.4	54.9	45.1	50.0	50.0
Total Mfg. Capacity	75.7	24.3	71.7	28.3	69.5	30.5	67.4	32.6

Part II

To gauge longer-range capacity conditions beyond 1981, please estimate for each depth range the time (in days) required to expand your maximum 1981 worldwide rig production capacity by the indicated rate.

	No. of Days Required to Expand 1981 Capacity by:			
	25%	**50%**	**75%**	**100%**
3,000-5,000 ft.	181	367	545	742
6,000-9,000 ft.	140	297	444	598
10,000-12,000 ft.	182	385	517	733
13,000-15,000 ft.	127	298	453	614
16,000 ft. & over	192	378	562	765
Total Mfg. Capacity				

	Range: Low-High			
3,000-5,000 ft.	100-318	180-900	240-1,095	360-1,460
6,000-9,000 ft.	100-318	180-900	240-1,095	360-1,460
10,000-12,000 ft.	120-318	180-900	220-1,095	360-1,460
13,000-15,000 ft.	0-365	180-900	360-1,095	360-1,460
16,000 ft. & over	120-365	180-900	220-1,095	360-1,460

Exhibit G-2

NATIONAL PETROLEUM COUNCIL
STUDY ON MATERIALS AND MANPOWER REQUIREMENTS

DRILLING EQUIPMENT TASK GROUP

SURVEY QUESTIONNAIRE FOR
TOOL JOINTS

Part I

In the table below, please estimate the following information for each year, 1978-1981:

(1) Your anticipated maximum **worldwide tool joint production capacity** in units (based on a 24-hour day, 5-day week).

(2) The **percentage utilization** you expect for this capacity.

(3) The approximate percentage of your worldwide capacity dedicated to: (a) U.S. markets, (b) foreign markets.

TOOL JOINT UNITS *

Year	Worldwide Capacity	% Utilizn.		Percent of Capacity Dedicated to: U.S. Market		Foreign Markets	
1978 (Actual)	802,349	716,498	89.3	681,194	84.9%	121,155	15.1%
1979 (Est.)	999,739	905,764	90.6	905,763	90.6%	93,976	9.4%
1980 (Est.)	1,161,200	1,120,558	96.5	895,285	77.1%	265,915	22.9%
1981 (Est.)	1,381,200	1,276,228	92.4	982,033	71.1%	399,167	28.9%

* A tool joint unit consists of a box and pin.

Part II

To gauge longer-range capacity conditions beyond 1981, please estimate the time (in days) required to expand your maximum 1981 worldwide tool joint production capability by the indicated rate.

	No. of Days Required to Expand 1981 Capacity by: 25%	50%	75%	100%
Days	431	588	687	808
Range of Numbers:				
High	730	1,090	1,090	1,090
Low	90	200	360	360

Exhibit G-3

NATIONAL PETROLEUM COUNCIL
STUDY ON MATERIALS AND MANPOWER REQUIREMENTS

DRILLING EQUIPMENT TASK GROUP

SURVEY QUESTIONNAIRE FOR
DRILL COLLARS

Part I

In the table below, please estimate the following information for each year, 1978-1981:

(1) Your anticipated maximum **worldwide drill collar production capacity** (based on a 24-hour day, 5-day week).

(2) The **percentage utilization** you expect for this capacity.

(3) The approximate percentage of your worldwide capacity dedicated to: (a) U.S. markets, (b) foreign markets.

UNITS OF DRILL COLLARS *

Year	Worldwide Capacity	% Utilizn.		Percent of Capacity Dedicated to: U.S. Market		Foreign Markets	
1978 (Actual)	42,558	37,749	88.7	32,131	75.5%	10,427	24.5%
1979 (Est.)	63,816	57,498	90.1	48,244	75.6%	15,572	24.4%
1980 (Est.)	74,896	68,978	92.1	53,550	71.5%	21,345	28.5%
1981 (Est.)	79,228	74,316	93.8	54,984	69.4%	24,244	30.6%

* Assume average drill collar length of 30 feet and a weight of 108 pounds per foot.

Part II

To gauge longer-range capacity conditions beyond 1981, please estimate the time (in days) required to expand your maximum 1981 worldwide drill collar production capability by the indicated rate.

	No. of Days Required to Expand 1981 Capacity by: 25%	50%	75%	100%
Days	282	538	638	727
Range of Numbers:				
High	500	700	720	1,200
Low	. 30	360	450	450

Exhibit G-4

NATIONAL PETROLEUM COUNCIL
STUDY ON MATERIALS AND MANPOWER REQUIREMENTS

DRILLING EQUIPMENT TASK GROUP

SURVEY QUESTIONNAIRE FOR
PRESSURE CONTROL HARDWARE

Part I

In the tables below, please estimate the following information for each year, 1978-1981:

(1) Your anticipated maximum **worldwide production capacity** in units (based on a 24-hour day, 5-day week).

(2) The **percentage utilization** you expect for this capacity.

(3) The approximate percentage of your worldwide capacity dedicated to: (a) U.S. markets, (b) foreign markets.

Since we are grouping sizes and pressure ratings together and are only considering the total units, please base the estimates on your typical product mix.

WORLDWIDE CAPACITY
(Units and % Utilization)

	1978 Actual		1979		1980		1981	
Products	**Capacity**	**% Utilizn.**	**Capacity**	**% Utilizn.**	**Capacity**	**% Utilizn.**	**Capacity**	**% Utilizn.**
Annular Preventers	1,040	77.7	1,325	93.8	1,440	94.0	1,690	94.3
Ram Preventers	2,350	97.8	2,960	95.3	3,710	95.6	3,950	95.8
Tubular BOPs:								
Kelly Valves	3,550	78.5	4,300	75.5	5,000	80.5	5,550	82.2
Drop-in Valves	300	100.0	950	36.8	1,100	45.5	1,400	100.0
Collet Connectors	30	30.0	30	30.0	30	25.0	30	25.0
Clamp Connectors	1,208	70.1	1,210	70.2	1,215	75.2	1,210	77.1
Swivels								
BOP Control Systems	806	57.9	1,310	79.9	1,420	89.5	1,420	89.5

WORLDWIDE CAPACITY DEDICATED TO U.S.
AND FOREIGN MARKETS
(Percentage)

	1978 Actual		1979		1980		1981	
Products	**U.S.**	**Foreign**	**U.S.**	**Foreign**	**U.S.**	**Foreign**	**U.S.**	**Foreign**
Annular Preventers	65.3	34.7	63.2	36.8	65.3	34.7	64.4	35.6
Ram Preventers	62.0	38.0	64.0	36.0	61.9	38.1	61.5	38.5
Tubular BOPs:								
Kelly Valves	73.2	26.8	71.2	28.8	70.0	30.0	72.7	27.3
Drop-in Valves	50.0	50.0	60.0	40.0	60.0	40.0	65.0	35.0
Collet Connectors	11.0	89.0	13.0	87.0	12.0	88.0	11.0	89.0
Clamp Connectors	60.2	39.8	60.2	39.8	62.1	37.9	62.0	38.0
Swivels								
BOP Control Systems	68.1	31.9	62.9	37.1	56.9	43.1	56.8	43.2

Exhibit G-4 (continued)

NPC Materials & Manpower Study
Drilling Equipment Task Group
Pressure Control Hardware Questionnaire
Page 2

Part II

To gauge longer-range capacity conditions beyond 1981, please estimate for each product category the time (in days) required to expand your maximum 1981 world-wide production capability by the indicated rate.

	No. of Days Required to Expand 1981 Capacity by:			
Products	**25%**	**50%**	**75%**	**100%**
Annular Preventers	324	450	628	658
Ram Preventers	236	330	566	616
Tubular BOPs:				
Kelly Valves	282	328	463	563
Drop-in Valves	180	180	360	360
Collet Connectors	365	365	730	730
Clamp Connectors	212	212	453	544
Swivels				
BOP Control Systems	92	177	360	360

Exhibit G-5

NATIONAL PETROLEUM COUNCIL
STUDY ON MATERIALS AND MANPOWER REQUIREMENTS

DRILLING EQUIPMENT TASK GROUP

SURVEY QUESTIONNAIRE FOR DRILLING FLUIDS

The National Petroleum Council has been asked by the Secretary of The Department of Energy to update and expand its September 1974 study, entitled "Availability of Materials, Manpower and Equipment for the Exploration, Drilling and Production of Oil—1974-1976." One aspect of the 1974 study was the availability and use of drilling fluids. The following questionnaire will enable the Drilling Equipment Task Group of the National Petroleum Council to obtain an updated picture of the use and availability of drilling fluids in the short term, 1978-1982, and the long term, 1990.

1. Which of the following products which are used in drilling fluids do you market, and are they in short supply to meet demand? Please indicate by checks in the appropriate column. Also, please list any other products that you market and which also might be in short supply.*

	Marketed by Your Company	In Short Supply
Barite	6	5
Bentonite	6	4
Lignosulfonates	6	3
Thinners (other than lignosulfonates)	5	3
Attapulgite Clay	6	1
Caustic Soda	6	2
Bactericides	4	2
Fluid Loss Control Agents	5	—2
Starch	1	0
CMC	1	0
Drisbac	1	0
Lost Circulation Material	1	1
Soda Ash	1	1
Soltex	1	1
Diesel Oil	1	1

* This list of products plus any additions to the list should be used in answering the next questions in the questionnaire.

Exhibit G-5 (continued)

2. For the indicated years, state your unit sales for the following drilling fluids products in the United States.

		Sales (in thousands)				
			Estimated			
	Units	1978	1979	1980	1981	1990
Barite	Tons	2,257.8	2,541.2	2,838.6	3,172.7	5,572.6
Bentonite	Tons	570.0	585.4	663.5	743.4	1,328.8
Lignosulfonates	Tons	59.4	65.6	70.9	77.6	129.6
Thinners (other than lignosulfonates)	Tons	17.3	19.9	22.4	25.4	41.3
Attapulgite Clay	Tons	35.9	39.8	43.9	50.3	85.3
Caustic Soda	Tons	39.3	42.8	46.9	51.9	86.6
Bactericides	Tons	4.0	4.6	5.4	5.9	12.5
Fluid Loss Control Agents	Tons	25.1	27.6	30.4	34.0	54.5
Calcium Chloride	Tons	4.6	5.5	6.1	6.9	12.0
Starch	Tons	.3	.2	.3	.3	—
Dricose	Tons	.04	.04	.04	.03	—
Drisbac	Tons	.02	.02	.02	.03	—

3. For the indicated years, state your unit sales for non-drilling fluids application (i.e., industrial, agricultural, etc.).

		Sales (in thousands)				
			Estimated			
	Units	1978	1979	1980	1981	1990
Barite	Tons	81.4	79.5	56.1	57.0	103.0
Bentonite	Tons	387.0	364.0	366.0	203.0	160.0
Lignosulfonates	Tons	14.0	9.0	6.0	5.0	—
Thinners (other than lignosulfonates)	Tons	—	—	—	—	—
Attapulgite Clay	Tons	—	—	—	—	—
Caustic Soda	Tons	—	—	—	—	—
Bactericides	Tons	—	—	—	—	—
Fluid Loss Control Agents	Tons	—	—	—	—	—
Lost Circulation Material	Tons	10.0	11.5	12.9	14.5	25.6
Soltex	Tons	.6	.7	.8	.9	1.5
Soda Ash	Tons	2.2	2.3	2.6	2.9	5.1

4. For the years indicated, how many tons of each of the products (for which sales were given in question 2) will actually be produced by your company? For those products not produced by your company, please indicate how many tons you will purchase to meet demand. Note that the figures given should include only those products that are produced or bought within the United States.

	U.S. PRODUCTION Estimated—(in thousands)					U.S. PURCHASES Estimated—(in thousands)				
	1978	1979	1980	1981	1990	1978	1979	1980	1981	1990
Barite	2,040.0	2,359.0	2,618.0	2,936.0	4,812.0	168.8	42.2	45.6	13.5	110.6
Bentonite	445.0	463.0	528.0	593.0	1,041.0	125.0	122.4	135.5	150.4	287.8
Lignosulfonates	34.5	34.9	37.3	39.8	66.0	23.9	29.7	33.6	36.8	61.6
Thinners (other than lignosulfonates)	11.0	12.9	14.4	15.7	27.3	6.3	7.0	8.0	9.7	14.0
Attapulgite Clay	—	—	—	—	—	35.9	39.9	44.0	50.0	85.3
Caustic Soda	—	—	—	—	—	39.3	42.8	46.9	51.9	86.6
Bactericides	—	—	—	—	—	4.0	4.6	5.4	5.9	12.5
Fluid Loss Control Agents	2.3	2.9	3.5	4.0	6.8	22.8	24.7	26.9	30.0	47.7
Calcium Chloride	—	—	—	—	—	4.6	5.5	6.1	6.9	12.0
Lost Circulation Material	—	—	—	—	—	10.0	11.5	12.9	14.5	25.6
Soltex	—	—	—	—	—	.6	.7	.8	.9	1.5
Starch	—	—	—	—	—	.3	.2	.3	.3	—
Dricose	—	—	—	—	—	.04	.04	.04	.03	—
Drisbac	—	—	—	—	—	.02	.02	.02	.03	—
Soda Ash	—	—	—	—	—	2.2	2.3	2.6	2.9	5.1

5. How many tons of each product will your company import, for the years indicated, to meet the product sales stated in Question 3?

	IMPORTED PRODUCTION Estimated—(in thousands)					IMPORTED PURCHASES Estimated—(in thousands)				
	1978	1979	1980	1981	1990	1978	1979	1980	1981	1990
Barite	12.0	33.0	50.0	50.0	75.0	37.0	107.0	125.0	173.2	575.0
Bentonite	—	—	—	—	—	—	—	—	—	—
Lignosulfonates	—	—	—	1.0	2.0	1.0	1.0	—	—	—
Thinners (other than lignosulfonates)	—	—	—	—	—	—	—	—	—	—
Attapulgite Clay	—	—	—	—	—	—	—	—	—	—
Caustic Soda	—	—	—	—	—	—	—	—	—	—
Bactericides	—	—	—	—	—	—	—	—	—	—
Fluid Loss Control Agents	—	—	—	—	—	—	—	—	—	—

Exhibit G-5 (continued)

6. Are any product sales constrained by production (cost or lack of availability) or purchase limitations? Please state the **additional** dollar sales that could be obtained if your company had all production and purchased sources available to it.

	ADDITIONAL DOLLAR PRODUCT SALES				
	Estimated—(in thousands)				
	1978	1979	1980	1981	1990
Barite	1,700	5,380	5,726	6,352	10,600
Bentonite	550	500	—	—	—
Lignosulfonates	4,000	2,000	2,000	4,000	8,000
Thinners (other than lignosulfonates)	—	—	—	—	—
Attapulgite Clay	—	—	—	—	—
Caustic Soda	—	—	—	—	—
Bactericides	—	—	—	—	—
Fluid Loss Control Agents	—	—	—	—	—

7. In terms of the packaging and distribution of the above products, which of the following act as constraints on the supply of these products to your customers? (In the space next to each item, please indicate the volume or number of each item that will be available, the volume or number of each item that you will be "short by" in meeting forecasted sales and the time delays in getting these items).

	Number Available	Number Short by	Time Delay (Avg. Days)
Rail Box Cars	510	760	740
Rail Hopper Cars	305	175	14
Trucks	44	—	—
Ships	—	—	—
Boxes	—	—	—
Drums	6,000	—	7
Bags	30,000	—	—
Plastic Wrap	—	—	90

8. In the table below, please identify any other constraints which would limit your ability to expand capacity or to make full utilization of your facilities in the future. Please indicate timing of the constraint and make any appropriate comments on the causes of the constraint or recommended solutions.

	TIMING OF CONSTRAINT (Check the Year of Impact)				
Factor	**1979**	**1980**	**1981**	**1982 & Beyond**	**Comments**
Available Capital	—	—	—	—	—
Manpower	1	1	2	2	—
Raw Material	3	3	3	4	—
Government Regulations	5	5	4	3	—
Other (list each) Fuel	1	1	1	1	—

9. For the countries that you import barite and bentonite from, please indicate the proven reserves that you feel are available to your company in each country. For drilling fluids, assume barite must be 4.2 specific gravity or greater. The reserves stated should be that which is economically processed and salable for the 1978-1990 time horizon. Include an estimate for United States in your answers.

	Reserves in Tons (in thousands)	
Country	**Barite**	**Bentonite**
United States	—	______
Canada	4,000	______
Australia	2,500	______
Brazil	750	______
Chile	550	______
China	1,000	______
Greece	1,100	______
Guatemala	3,000	______
India	30,500	______
Iran	800	______
Ireland	3,800	______
Italy (inc. Sardinia)	300	______
Mexico	1,300	______
Morocco	700	______
Peru	4,000	______
Thailand	7,000	______
Turkey	100	______
Belgium	500	______
Malagasy	1,000	______

APPENDIX H
Tubular Steel

Tubular Steel

The projected capacity of the domestic steel industry for the production of oil country tubular goods was developed through a questionnaire sent to 15 domestic steel companies. Companies included in the survey were:

American Seamless Tubing, Inc.
Armco Steel Corporation
Babcock & Wilcox Co.
CF&I Steel Corporation
Cal-Metal Corporation[1]
Fort Worth Pipe & Supply
Interlake, Inc.
Jones & Laughlin Steel Corporation
Kaiser Steel Corporation
Lone Star Steel Company
National Pipe & Tube Company
Quanex Corporation
Republic Steel Corporation
United States Steel Corporation
Wheeling-Pittsburgh Steel Corporation

Each steel company was requested to make the following assumptions in projecting its annual capacity for the years 1978 through 1981 and for the years 1985 and 1990.

1. A supply of raw steel will be readily available for the tube mills.
2. There will be no work stoppages (in the mines, mills, or transportation network) that would limit production.
3. Energy (coke, coal, gas, fuel oil, and electricty) will be available in normal quantities.
4. The mills will be down a normal length of time for maintenance (including an annual shutdown if such is the normal practice).
5. The mills will be operated with the split between OCTG and non-OCTG being that which mill management considers optimum, taking into consideration hot mill capacity, heat treat capacity, upsetting capacity, finishing capacity, and scheduling. Assume there will be market demand for all tubulars the mill(s) can produce.
6. Mills will be operated at what mill management considers the optimum number of turns for full capacity, and mill crews will have been in place a sufficient length of time that the mills will be operating at a high rate of efficiency.

[1] Operations ceased.

7. There will be a product mix (sizes, weights, grades, and end finishes—carbon and high strength/alloy) that mill management considers optimum for the mill(s) taking market demand into consideration. Assume market demand will be 78 percent casing, 18 percent tubing, and 4 percent drill pipe.
8. There will be no government directives to produce non-OCTG products (such as ordinance).

The questionnaire included the following notes:

- Include capacity resulting from new equipment additions currently in progress plus additions planned during the period covered by the survey.
- Capacity should represent the total OCTG capacity of the company. *Do not* break down capacity by mill.
- Include API as well as non-API tonnage.

Table H-1 summarizes the projected domestic capacity for the production of casing, tubing, and drill pipe. Table H-2 summarizes projected capacity for carbon versus high strength OCTG. Table H-3 summarizes the projection by the mills of the tonnage of tubulars that will be shipped to third party end finishers for cutting proprietary and API threads. Table H-4 summarizes the projected capacity for seamless versus welded OCTG.

TABLE H-1

PROJECTED DOMESTIC CAPACITY FOR THE PRODUCTION OF CASING, TUBING, AND DRILL PIPE (Short Tons)

	1978	1979	1980	1981	1985	1990
Casing						
Carbon	1,339,225	1,362,170	1,416,120	1,427,199	1,378,501	1,384,801
High Strength	932,908	1,014,950	1,096,710	1,208,110	1,412,510	1,416,610
Total Casing	2,272,133	2,377,120	2,512,830	2,635,309	2,791,011	2,801,411
% of Total	(77.5)	(75.7)	(76.2)	(75.6)	(75.4)	(75.1)
Tubing						
Carbon	308,289	371,510	376,201	391,677	409,439	419,939
High Strength	207,151	244,890	262,900	306,270	348,200	353,000
Total Tubing	515,440	616,400	639,101	697,947	757,639	772,939
% of Total	(17.6)	(19.6)	(19.4)	(20.0)	(20.5)	(20.7)
Drill Pipe						
Carbon	0	0	0	0	0	0
High Strength	142,400	146,000	146,500	151,000	155,000	157,000
Total Drill Pipe	142,400	146,000	146,500	151,000	155,000	157,000
% of Total	(4.9)	(4.7)	(4.4)	(4.3)	(4.2)	(4.2)
Total OCTG						
Carbon	1,647,514	1,733,680	1,792,321	1,818,876	1,787,940	1,804,740
High Strength	1,282,459	1,405,840	1,506,110	1,665,380	1,915,710	1,926,610
Grand Total	**2,929,973**	**3,139,520**	**3,298,431**	**3,484,256**	**3,703,650**	**3,731,350**

TABLE H-2

PROJECTED DOMESTIC CAPACITY
OIL COUNTRY TUBULAR GOODS
CARBON VERSUS HIGH STRENGTH
(Short Tons)

	1978	1979	1980	1981	1985	1990
Carbon						
Casing	1,339,225	1,362,170	1,416,120	1,427,199	1,378,501	1,384,801
Tubing	308,289	371,510	376,201	391,677	409,439	419,939
Drill Pipe	0	0	0	0	0	0
Total Carbon	1,647,514	1,733,680	1,792,321	1,818,876	1,787,940	1,804,740
% of Total	(56.2)	(55.2)	(54.3)	(52.2)	(48.3)	(48.4)
High Strength						
Casing	932,908	1,014,950	1,096,710	1,208,110	1,412,510	1,416,610
Tubing	207,151	244,890	262,900	306,270	348,200	353,000
Drill Pipe	142,400	146,000	146,500	151,000	155,000	157,000
Total High Strength	1,282,459	1,405,840	1,506,110	1,665,380	1,915,710	1,926,610
% of Total	(43.8)	(44.8)	(45.7)	(47.8)	(51.7)	(51.6)
Total OCTG	**2,929,973**	**3,139,520**	**3,298,431**	**3,484,256**	**3,703,650**	**3,731,350**

TABLE H-3

PROJECTED DOMESTIC CAPACITY
OIL COUNTRY TUBULAR GOODS
SHIPPED TO THIRD PARTY END FINISHERS
(Short Tons)

	1978	1979	1980	1981	1985	1990
Tubulars Shipped To Third Party End Finishers For Proprietary and API Threads						
Casing	207,646	213,696	247,774	249,774	258,174	258,174
Tubing	150,515	173,470	174,995	199,595	223,195	218,195
Total	**358,161**	**387,166**	**422,769**	**449,369**	**481,369**	**476,369**
% of Total OCTG	(12.2)	(12.3)	(12.8)	(12.9)	(13.0)	(12.8)

TABLE H-4

PROJECTED DOMESTIC CAPACITY OIL COUNTRY TUBULAR GOODS SEAMLESS VERSUS WELDED (Short Tons)

	1978	1979	1980	1981	1985	1990
Seamless						
Casing	1,506,331	1,616,820	1,698,564	1,769,764	1,844,264	1,844,264
Tubing	366,977	424,600	434,300	465,900	494,000	506,700
Drill Pipe	142,400	146,000	146,500	151,000	155,000	157,000
Total Seamless	2,015,708	2,187,420	2,279,364	2,386,664	2,493,264	2,507,964
% of Total	(68.8)	(69.7)	(69.1)	(68.5)	(67.3)	(67.2)
CW *						
Tubing	43,250	48,100	51,000	52,900	57,000	57,000
% of Total	(1.5)	(1.5)	(1.6)	(1.5)	(1.5)	(1.5)
ERW †						
Casing	765,802	760,300	814,266	865,545	946,747	957,147
Tubing	105,213	143,700	153,801	179,147	206,639	209,239
Total ERW	871,015	904,000	968,067	1,044,692	1,153,386	1,166,386
% of Total	(29.7)	(28.8)	(29.3)	(30.0)	(31.1)	(31.3)
Total OCTG	**2,929,973**	**3,139,520**	**3,298,431**	**3,484,256**	**3,703,650**	**3,731,350**

* Continuous weld.
† Electric resistance weld.

APPENDIX I

Production Equipment

Production Equipment

The basic method used to compare production equipment manufacturing capacity to oil and gas industry activity involved indexing past, present, and projected future plant capacities to respective periods of oil and gas industry activity levels. The figures and tables in this appendix provide *well population* data used in determining if there would be sufficient amounts of equipment manufactured to complete and operate the projected number of oil and gas wells.

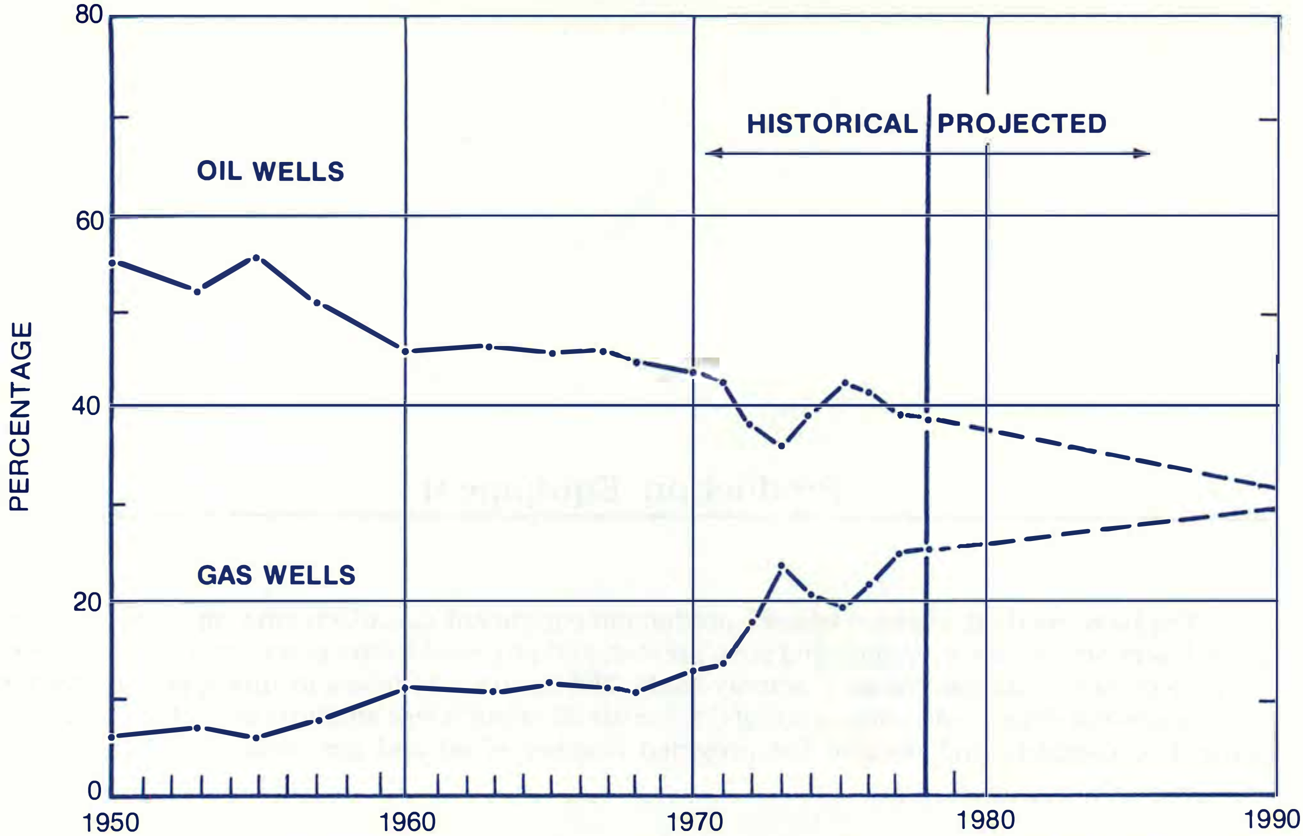
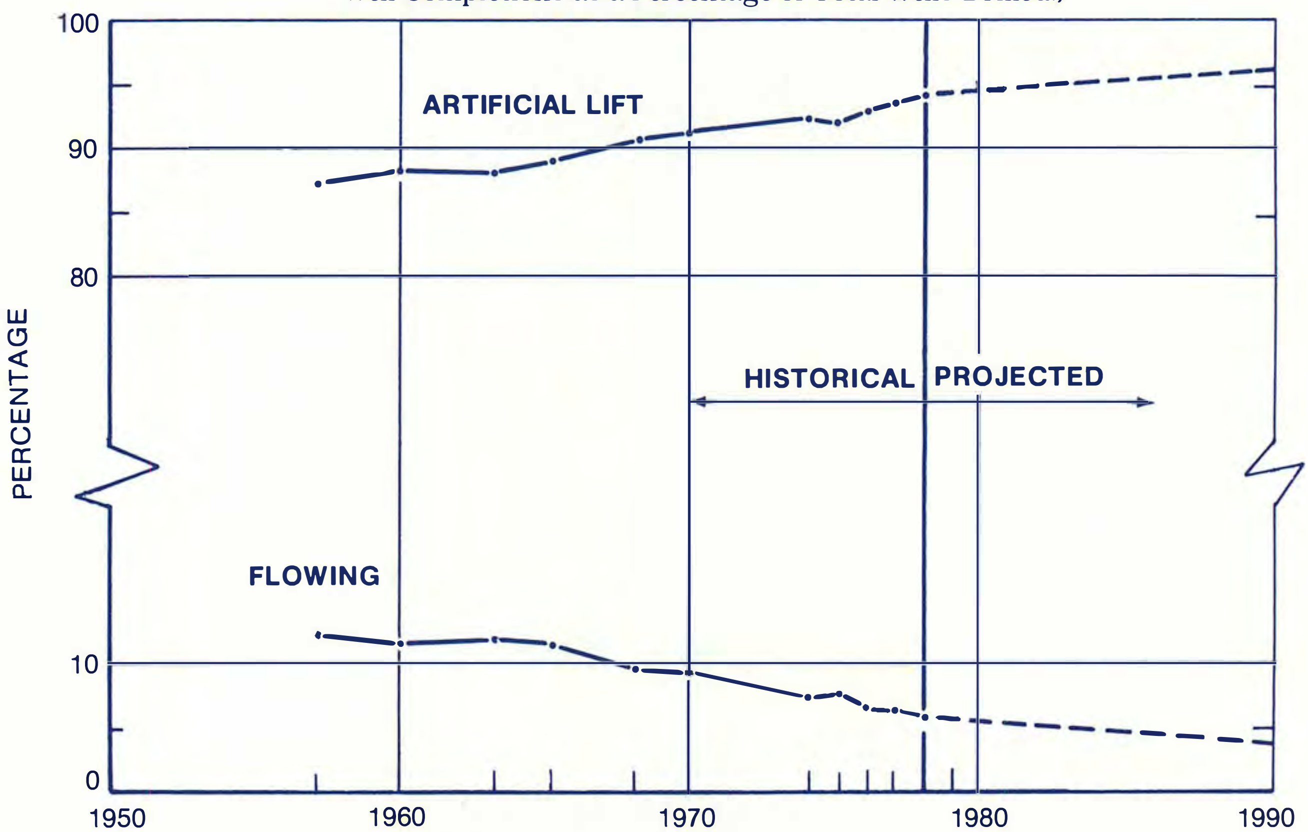


Figure I-1. U.S. Drilling Activity–New Development and Exploration Wells (Oil and Gas Well Completions as a Percentage of Total Wells Drilled.)



SOURCES: API Statistics; *Petroleum Engineering International; World Oil.*

Figure I-2. U.S. Producing Oil Wells (Artificial Lift and Flowing Oil Wells as a Percentage of Total Producing Oil Wells).

TABLE I-1
PROJECTION OF ACTIVE PRODUCING WELLS

	Oil Wells					Gas Wells				Total	
		New Wells Completed				New Wells Completed					
	Wells Drilled *	% of Wells Drilled †	Wells	Wells Removed From Service §	Year End Active Producers ¶	% of Wells Drilled †	Wells	Wells Removed From Service **	Year End Active Producers **	Wells	% Increase (decrease)
1970	29,545	42.9	12,666	24,400	530,990	13.4	3,945	900	117,483	648,473	—
1971	27,712	41.9	11,606	25,278	517,318	14.1	3,901	1,174	120,210	637,528	(1.7)
1972	29,484	37.9	11,159	20,034	508,443	18.3	5,384	4,436	121,158	629,601	(1.2)
1973	28,670	35.1	10,075	21,140	497,378	24.0	6,869	3,849	124,178	621,556	(1.3)
1974	34,364	39.1	13,441	13,188	497,631	20.5	7,047	4,876	126,349	623,980	0.4
1975	40,693	41.1	16,715	14,013	500,333	19.8	8,050	2,304	132,095	632,428	1.4
1976	42,310	41.0	17,365	18,588	499,110	21.8	9,235	3,887	137,443	636,533	0.7
1977	46,077	39.3	18,095	10,205	507,000	25.1	11,565	1,008	148,000	655,000	2.9
1978 (prelim)	48,800	36.4	17,767	17,167	507,600	26.8	13,098	7,498	153,600	661,200	1.0
1979	52,000	36.7	19,100	13,500	513,200	26.7	13,900	3,900	163,600	676,800	2.4
1980	58,300	36.0	21,000	13,500	520,700	26.9	15,700	3,900	175,400	696,100	2.9
1981	60,400	35.4	21,400	13,500	528,600	27.3	16,500	3,900	188,000	716,600	2.9
1985	63,200	33.1	20,900	13,500	558,900	29.0	18,300	3,900	242,800	801,700	2.9
1990	75,400	31.2	23,500	13,500	603,900	29.0	21,900	3,900	399,900	1,003,800	5.0

* 1970-77—Per API Drilling Statistics resequenced based on completion date; 1978 estimated final completions; 1979-90 based on projected upper level drilling activity.

† 1970-78—Calculated actual; 1970-90 projected per historic trends shown on Figure I-1.

§ 1970-78—Calculated from active well census and new wells drilled; 1979-90 projected based on 1973-74 average.

¶ 1970-77—Per U.S. Department of Energy Annual Petroleum Statements (formerly U.S. Bureau of Mines); 1976 per *World Oil* (February 15, 1979); 1979-90 net after projected new wells and abandonments.

** 1970-78—Calculated from active well census and new wells drilled; 1979-90 projected based on average of 1973-78 period.

TABLE I-2

U.S. STRIPPER WELLS AND ABANDONMENTS

	Stripper Wells (at year end)	Percent of U.S. Crude Oil Production (during year)	Percent of U.S. Active Oil Wells (at year end)	Number of Abandonments (at year end) *
1963	401,031	19.5	68.1	14,363
1964	394,107	19.2	67.0	14,476
1965	398,299	20.7	67.6	15,456
1966	380,549	16.0	65.2	16,267
1967	376,851	15.5	66.7	14,986
1968	367,205	14.6	66.3	20,496
1969	358,650	13.5	66.2	15,618
1970	359,130	12.5	67.6	15,631
1971	353,696	12.3	68.4	18,421
1972	359,451	11.9	70.7	13,483
1973	355,229	11.5	71.4	13,756
1974	366,095	12.9	73.6	13,779
1975	367,872	12.9	73.5	13,478
1976	365,733	13.2	73.3	9,916
1977	368,930	13.1	72.8	9,000

SOURCE: *National Stripper Well Survey*, Interstate Oil Compact Commission.

* All wells reported as abandoned in Lower 48 onshore and state waters.

APPENDIX J

Manpower

Manpower

Discussion of Professional Personnel

The three professional disciplines that are critical to exploration and production activity are: geophysics, geology, and engineering. Each professional group is discussed individually in the following pages.

Geophysicists

Geophysical measurements taken at the surface provide the major clues for locating potential subsurface reservoirs which may contain hydrocarbons (as described in Chapter Two). Professional geophysicists may come from diverse academic backgrounds and are divided into three categories: data processors, geophysical analysts, and geophysical interpreters.

Data processors must be conversant with the basic physics involved in seismic wave propagation, have some understanding of geology and rock properties, and be skilled in computer sciences. Their academic background may be in geophysics or geology, but is more likely to be in mathematics, physics, electrical engineering, or computer science.

Geophysical analysts must be knowledgeable in the physics of wave propagation. They must also have a greater understanding of geology and rock properties than the data processor, but proficiency in computer sciences is not required. Their academic background is likely to be in geophysics or geology, but may be in mathematics, physics, or engineering.

Geophysical interpreters must be most competent in geology, but must also understand seismic wave propagation theory and have some understanding of data processing operations. Their academic background is most likely to be in geology or geophysics.

All professional geophysicists must have an understanding of the data collection process.

Professional geophysics recruits require training to reach an acceptable level of competence. Data processors require one to two years of training and experience. They usually become geophysical analysts, who normally have a minimum of three to five years of experience. Geophysical interpreters normally have five or more years of experience and have worked as data processors and analysts.

Based on Department of Labor statistics for earth scientist manpower (discussed in the following section on geologists), it was calculated that about 5,000 professional geophysicists were employed in the U.S. oil and gas industry in 1970, and about 7,900 in 1976. It was estimated that the number had increased 12.5 percent yearly to 10,000 in 1978.

From a survey of representative companies in the industry and the membership rolls of the Society of Exploration Geophysicists, the academic background of professional geophysicists working in the oil and gas industry was estimated as follows:

- Degrees in geophysics—30 percent
- Degrees in geology—30 percent
- Other degrees (mathematics, physics, engineering, computer science)—40 percent.

To continue the growth rate that has been experienced since 1976 would require 1,000 to 1,200 additional geophysicists each year to 1981, and 1,500 more in future years (in addition to replacements for attrition). However, based on projected exploratory wells drilled, growth on the order of six to seven percent yearly is more likely (Chapter Seven, Table 30).

Need for interpretation of seismic survey data from offshore China has created a present surge in workload for geophysicists. This is probably a short-term situation and, to date, has been met in large measure by consultants and retired personnel returning to active service. It is not likely to have a long-term impact on demand for geophysicists during the period covered by the survey.

A 1978 survey made by the International Association of Geophysical Contractors indicated that schools awarding degrees in geophysics expected the number of graduates in that field to be as shown in Table J-1.

TABLE J-1
PROJECTION OF GEOPHYSICS GRADUATES

Year	Number of Graduates
1978	315-325
1979	350-360
1980	350-360
1981	350-360
1982	328-338
1983	306-316
1984	284-294
1985	262-272

The schools surveyed have the capacity to graduate about 400 geophysics students per year, but projected declining numbers will be graduating after 1981, based on historical cyclic demand. A graduation rate of 350 to 400 per year would be sufficient to maintain the current mix of 30 percent with geophysics degrees among the professionals recruited to meet force growth, but probably not force growth plus replacements for attrition. However, there is a large manpower supply of graduating geologists who are not employed as geologists by the oil and gas industry (Chapter Seven, Figure 22), and a much larger supply of other graduates (mathematics, physics, engineering, computer sciences) to fill the projected need for professional geophysicists if the 1976-1978 high growth rate continues.

It was concluded that the number of required geophysicists will be recruited in order to continue the recent high growth rate. Lack of experience of new and recent employees is being met by the industry's accelerating training programs to raise skills and judgment to the required levels. Also, the increased use of automated computer-based methods of analysis and interpretation substantially increases the productivity of analysts and interpreters.

Geologists

The petroleum geologist is the basic generator of new ideas and prospects to which geophysics is then normally applied in both exploration and production operations. He is responsible for the evaluation of wildcat and field wells as they are drilled. His interpretation of well logging results and earth samples as they are brought up by the drill bit determine if the well has penetrated hydrocarbon zones. The geologist coordinates his activities with the geophysicist, the landman, the drilling engineer, and the production and reservoir engineer, cooperating and advising to accomplish matters of mutual concern.

Geologists study the structure, composition, and history of the earth's crust. They determine the types and disposition of rocks on and beneath the surface. In searching for petroleum, the geologist looks for the the three essentials which follow.

- Source beds of shales or limestones which originally contained organic remains
- Porous sandstones or limestones which later became the reservoir beds of migrating oil and gas
- Traps which have sealed off the reservoir beds and held the hydrocarbon in place.

The geologist creates maps of the earth as it may have existed during various periods of geologic time, and prepares cross sections which show formation thicknesses, anticlines, faults, and other traps that have resulted from changes in the earth's structure.

Specialists in petroleum geology include:

- Paleontologists, who study fossil remains to identify oil-bearing strata
- Mineralogists, who study physical and chemical properties of rock samples
- Stratigraphers, who determine the rock layers most likely to contain oil and natural gas
- Photogeologists, who examine and interpret aerial photographs of the land surface
- Petrogeologists, who investigate the composition of all types of rocks.

About two-thirds of all petroleum geologists are employed by oil companies; the others are consultants and independents engaged in their own petroleum-related business.

No single source of data or specific figures is available to establish historical trends over the period of interest, 1973-1978, from which projections of supply and demand for petroleum geologists can be made. Primary sources used in calculating the historical population of both geologists and geophysicists were extracted from the U.S. Department of Labor's biannual publication, *Occupational Outlook Handbook—Earth Scientists* (see Table J-2), and its unpublished statistics, *National Industrial Occupational Matrix—Earth Scientists* (see Table J-3). These Department of Labor data are derived from census figures and are subject to some error. Also utilized was the *Society of Exploration Geophysicists (SEG) Membership Distribution, 1976* (see Table J-4).

It was assumed that the earth scientists enumerated in the Department of Labor statistics were either geologists or geophysicists. For the purpose of this study, therefore, the number of geologists was calculated by subtracting the calculated number of geophysicists from the total number of earth scientists employed in the oil and gas industry. For example, Table J-2 shows that in 1976

TABLE J-2

POPULATION OF EARTH SCIENTISTS

	1970	1972	1974	1976
Geologists				
Government	1,700	1,600	1,600	2,000
Teachers	6,000	7,500	7,500	9,500
Other	15,300	13,800	13,800	22,500
Subtotal	**23,000**	**22,900**	**22,900**	**34,000**
Geophysicists				
Government	1,900	2,000	2,000	2,300
Teachers	500	600	600	700
Other	5,600	5,400	5,400	9,000
Subtotal	**8,000**	**8,000**	**8,000**	**12,000**
Total Geologists & Geophysicists				
Government	3,600	3,600	3,600	4,300
Teachers	6,500	8,100	8,100	10,200
Other	20,900	19,200	19,200	31,500
Total	**31,000**	**30,900**	**30,900**	**46,000**

SOURCE: *Biennial Occupation Outlook Handbook*, Department of Labor.

TABLE J-3

POPULATION OF EARTH SCIENTISTS

	1970	1976
Oil & Gas		
Extraction	12,350	20,820
Refining	720	1,130
Consultant/Independent	2,640	4,520
Subtotal	**15,710**	**26,470**
Non-Oil & Gas		
Mining	1,680	2,260
Construction	100	160
Public Utilities (non-government)	190	310
Manufacturing	480	750
Engineering & Architectural Services	720	1,130
Sales	480	750
Other	370	310
Subtotal	**4,020**	**5,670**
Government		
Corps of Engineers	870	970
Public Utilities (TVA, etc.)	50	70
Other (Bureau of Mines, USGS, etc.)		
Subtotal	**3,560**	**4,430**
Education		
Education Services—Geology	720	1,130
Teachers—Geology	5,280	8,370
Teachers—Geophysics	500	700
Subtotal	**6,500**	**10,200**
Grand Total	**29,790**	**46,770**

SOURCE: Unpublished statistics, National Industrial Occupational Matrix, Department of Labor.

there were 9,000 geophysicists other than government employees and teachers. In Table J-4, the 77.1 percent oil and gas industry membership in 1976 represents about 88 percent of total industry membership. From this it was calculated that there were 7,920 geophysicists in the oil and gas industry. Subtracting 7,920 from the 26,470 earth scientists in the oil and gas industry in 1976 (shown in Table J-3), resulted in a figure of 18,550 geologists, which was rounded to 18,500 in Table J-5. The number of geologists in government and academia, and the total in 1976 shown in Table J-5 were taken from Table J-2; the number employed in other industries was derived by deduction.

The same calculations, based on the 1970 figures from Tables J-2 and J-3 and the 1976 Society of Exploration Geophysists membership distribution, gave a figure of approximately 10,500 geologists, which was judged to be low and was adjusted upward to 12,000. The figures for geologists in the oil and gas industry in 1972 and 1974 were estimated with the assumption that there were more employed in oil and gas in 1974 than in 1972, although Table J-2 shows the same total in *other* (industry) for both years, and the totals for all geologists and earth scientists are the same from 1970 through 1974.

Additions to geological personnel in the oil and gas industry from 1976 through 1978 were calculated, based on the American Geological Institute's survey of student enrollment in geoscience departments. It was assumed that 80 percent of the juniors and seniors enrolled in the academic years 1975-1976 and 1976-1977 graduated; of those graduates, 65 percent were employed as geologists, and 65 percent of those entered the oil and gas industry. Thus, the 11,500 juniors and seniors in 1976 and 1977 provided 9,200 geology graduates in 1977 and 1978. Six thousand were employed

TABLE J-4

MEMBERSHIP DISTRIBUTION
SOCIETY FOR EXPLORATION GEOPHYSICISTS—1976

	Percentage	
	All	Industry
Oil and Gas Industry		
Oil Companies	50.8	
Geophysical Contractors	14.6	
Consultants	11.7	
Subtotal	**77.1**	**87.9**
Other Industry		
Mining	2.7	
Manufacturing	2.1	
Service	2.4	
Supply	0.4	
Other	3.0	
Subtotal	**10.6**	**12.1**
Total Industry	87.7	100.0
Government	6.7	
Academia	5.6	
Total	**100.0**	

TABLE J-5

ESTIMATED POPULATION—U.S. GEOLOGISTS

	1970	1972	1974	1976	Estimated 1978
Industry					
Oil and Gas	12,000	10,500	10,800	18,500	22,400
Other	3,300	3,300	3,000	4,000	4,700
Total Industry	**15,300**	**13,800**	**13,800**	**22,500**	**27,100**
Government	1,700	1,600	1,600	2,000	2,600
Academia	6,000	7,500	7,500	9,500	10,300
Total U.S.	**23,000**	**22,900**	**22,900**	**34,000**	**40,000**

SOURCE: 1970-1976 data from Table J-2.

as geologists and about 3,900 were hired by the oil and gas industry. These calculations result in the estimated 22,400 geologists employed in the oil and gas industry in 1978, shown in Table J-5. The 2,600 estimated to be working for the government in 1978 may be low. The extrapolation is very rough and a substantial number of the 3,200 1977-1978 graduates assumed not employed as geologists could have taken government positions.

The petroleum geologists' growth rate of 30 percent per year from 1974 to 1976 and 20 percent per year from 1974 to 1978 should not be assumed to be sustainable. The year 1973 marked the end of a 15-year contraction of U.S. oil and gas exploration and development. The rapid increases following 1973 were made by drawing on a reserve of manpower that was largely independent of educational institutions. An annual growth rate of 11.5 percent is a more reasonable maximum expectation and would result in 48,000 petroleum geologists in 1985 and 83,000 in 1990. This percentage was indicated by the growth in membership of the American Association of Petroleum Geologists during the years 1947-1957, when the industry was operating essentially at capacity. It slightly exceeds the 1976-1978 calculated trend of 10 percent per year, which would result in 44,000 in 1985 and 70,000 in 1990.

Projections of future geologist manpower requirements were developed by questionnaires sent to 68 oil and gas companies, 48 of whom responded. Each was asked:

- How many total professional technical geologists do you now (1978) have employed domestically as practicing oil and gas geologists in exploration development and research programs?
- How many geologists do you expect to have during the following years to do planned programs? 1979, 1980, 1981, 1985, 1990?
- Assuming that there is some maximum level of domestic programs you could do, which is in excess of that planned, how many in each of these same years would you have?

Constraints which could limit projected activity to a maximum level were not defined. Each company made individual growth assumptions which added up to the totals shown in Table J-6.

TABLE J-6

PROJECTED GEOLOGICAL MANPOWER REQUIREMENTS
(Survey Totals)

	1978	1979	1980	1981	1985	1990
Planned Program						
Independents	552	644	723	806	922	1,020
Majors	3,515	3,859	3,993	4,123	4,311	4,378
Total Sample	**4,067***	**4,503**	**4,716**	**4,929**	**5,233**	**5,398**
Maximum Program						
Independents	552	708	818	924	1,150	1,315
Majors	3,515	4,005	4,260	4,437	4,608	4,868
Total Sample	**4,067**	**4,713**	**5,078**	**5,361**	**5,758**	**6,183**
Estimated Force † (thousands)	22.4	26.2	28.2	29.8	32.0	34.4

* Represents estimated 18 percent of total force.
† 1978 data from Table J-5; 1979-1990 is sample total divided by 18 percent to develop estimated total force.

The 4,067 geologists reported by the 48 respondents for 1978 represent 18 percent of the 22,400 estimated 1978 total oil and gas industry geologists (shown in Table J-5). Applying the 18 percent factor to the data in Table J-6, total oil and gas industry geological manpower requirements from 1978-1990 were calculated and are shown in Figure J-1.

The projected maximum number of geologists required is shown in Table J-7, along with the Outlook projected upper limit of the possible number of wells to be drilled. Except for the year

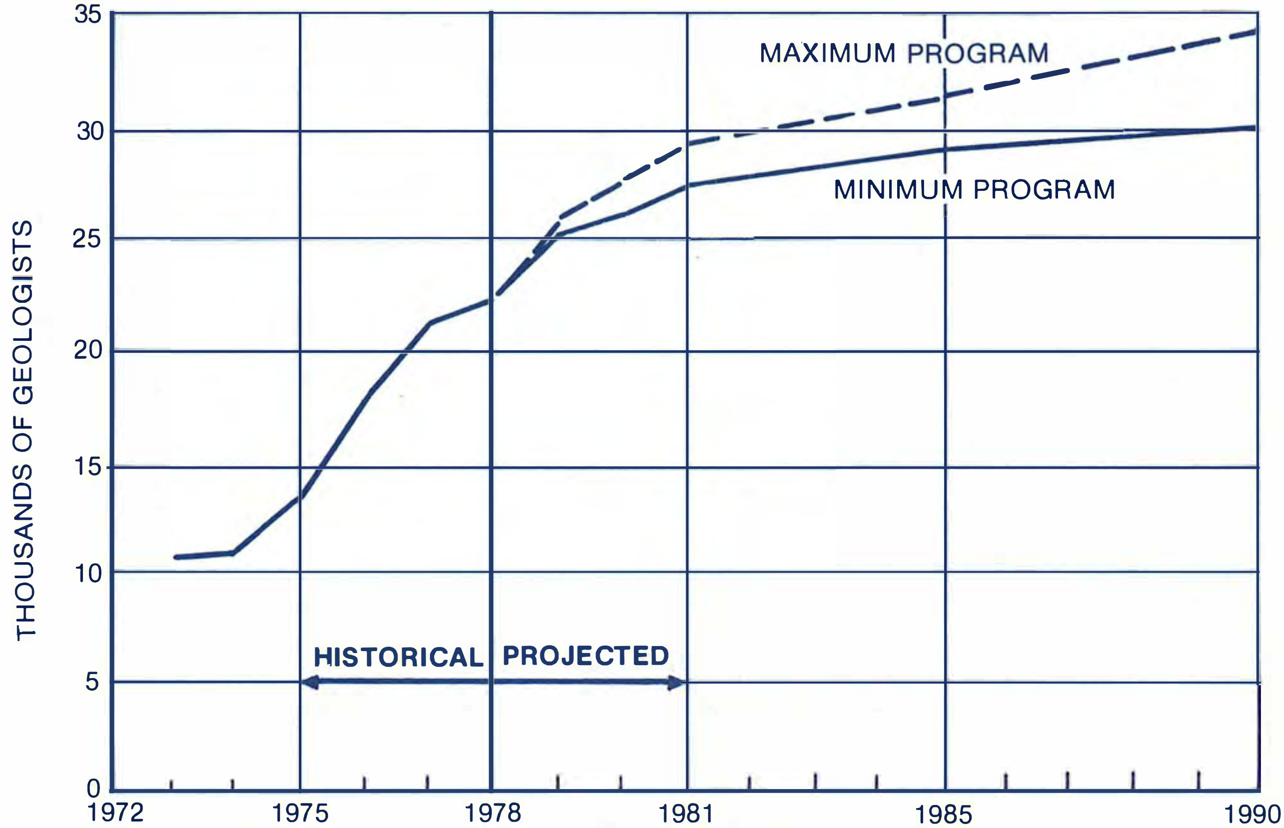


Figure J-1. Oil and Gas Industry Geological Manpower Requirements.

TABLE J-7

PROJECTED WELLS AND GEOLOGICAL MANPOWER REQUIREMENTS

	Upper Limit Wells		Maximum Geologic Manpower		
	Wells (thousands)	Annual Growth Rate (percentage)	Geologists (thousands)	Annual Growth Rate (percentage)	Wells Per Geologist Per Year
1978	48.8	—	22.4	—	2.2
1979	52.0	6.6	26.2	17.0	2.0
1980	55.3	6.4	28.2	7.6	2.0
1981	58.0	4.9	29.8	5.7	1.9
1985	64.6	2.7	32.0	1.8	2.0
1990*	75.4	3.1	34.4	1.5	2.2

* Including possible enhanced oil recovery programs.

1979, projected maximum growth rate in geological manpower requirements is not significantly different from the upper limit growth rate in projected wells to be drilled.

These figures show a reduction of projected maximum activity after 1981, while the number of wells drilled per geologist per year remains almost constant at about two until the projected step-up in drilling for enhanced oil recovery.

Few companies responding to the survey indicated that geological manpower is considered a possible constraint to increased activity. Any short-term shortage can be relieved rapidly by the increasing number of graduates, and by hiring the large number of geologists employed outside of the oil and gas industry.

Most respondents indicated that the opening of a new foreign frontier province would have little or no effect on domestic capability.

A substantial increase in demand for geologists would be expected even if there were significant changes in geological technology.

In order to project the potential number of geology graduates available to the oil and gas industry in the future, 43 university geology departments were surveyed by questionnaire, and 30 responded. Comparison of the enrollment of the respondents for the five academic years 1971-1972 through 1975-1976, with total enrollment in U.S. schools of geology compiled by the American Geological Institute, showed that responding schools represented about eight percent of total U.S. enrollment. Total enrollment by degree in the responding schools is shown in Table J-8.

Table J-9 shows the dramatic increase in enrollment since 1974. It is expected to drop, however, from an average growth rate of 19 percent per year for the three years ending in 1979 to about eight percent during the 1979-1980 school year.

TABLE J-8

ENROLLMENT OF GEOLOGY STUDENTS BY DEGREE
(30 Schools)

School Year	Bachelor's	Master's	Ph.D.	Total
1978-79	4,538	1,446	429	6,413
1979-80	4,919	1,542	457	6,918

Percentage Change from 1978-79 to 1979-80

Bachelor's	8.4
Master's	6.6
Ph.D.	6.5
Total	**7.9**

TABLE J-9

RELATIVE ENROLLMENT INCREASES BY YEAR
(30 Schools)

1971-72	to	1972-73	+	5.0%
1972-73	to	1973-74	+	3.1%
1973-74	to	1974-75	+	4.5%
1974-75	to	1975-76	+	12.8%
1975-76	to	1978-79	+	18.% compounded yearly
1978-79	to	1979-80	+	7.8%

About half of the schools expect enrollment trends to stabilize, one-third expect increases, and a small percentage predict declining enrollments. Based on these opinions and on recent history, enrollment was projected to increase at an eight percent annual rate, as shown in Figure J-2.

It has been the experience of schools that 30 to 40 percent of their enrolled geology students receive degrees each year. The calculations were made for Table J-10 based on this experience and the assumptions that there will be an annual enrollment increase of eight percent to 1985 and that 66 percent of new graduates will be available to the oil and gas industry.

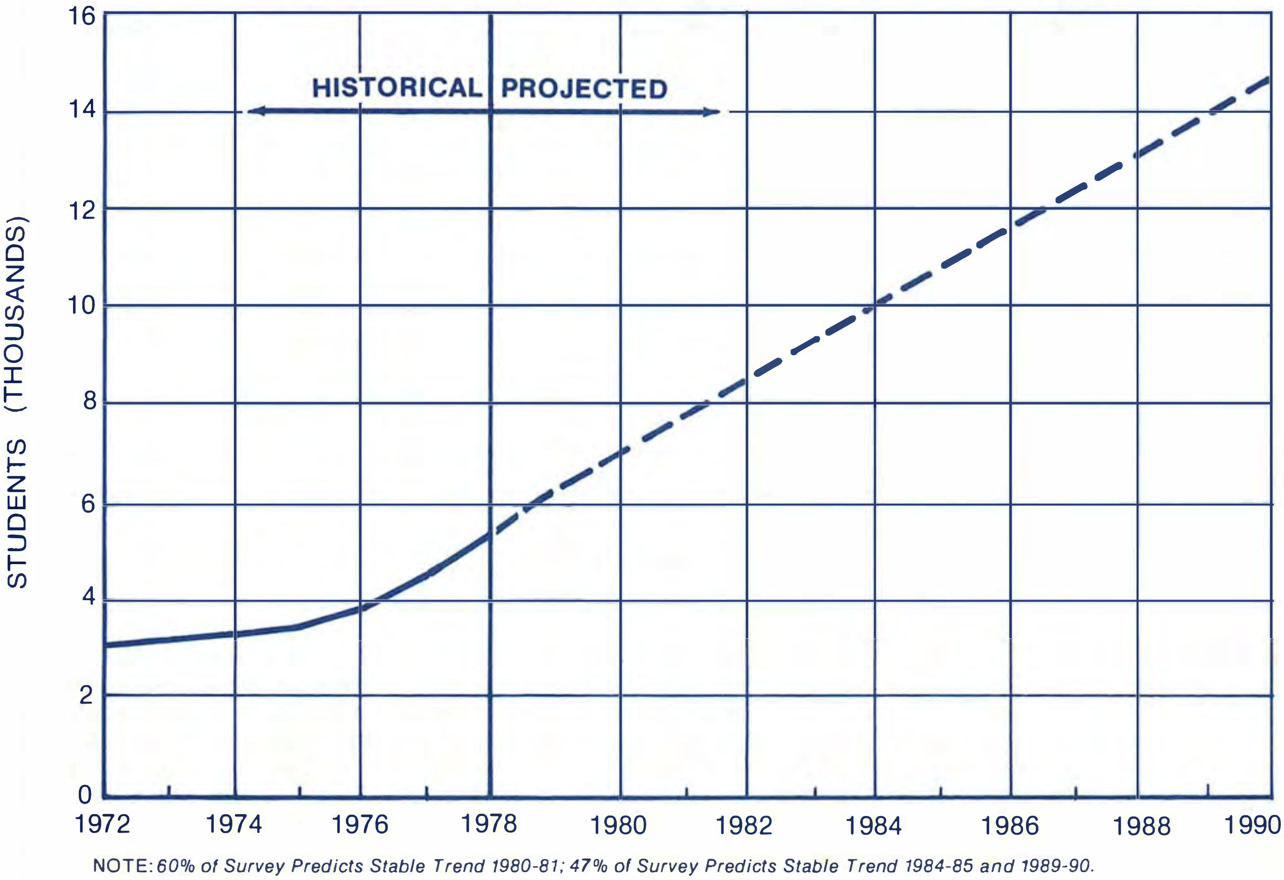


Figure J-2. Geology Student Enrollment Trends-Estimated Total Enrollment Based on Thirty School Samples.

In the past, most geology graduates employed as professional geologists by oil and gas companies have been hired at the M.S. or Ph.D. level. The bulk of B.S. graduates entering this industry went into geophysical services or into service companies. A more realistic assessment of professional geologist availability is the examination of the projected number of M.S. and Ph.D. graduates (shown in Table J-11). It was assumed that enrollment in graduate programs would increase at an annual rate of six percent, and this is the current trend.

Starting with a 1978 population of 22,400 (Table J-5) and assuming that 66 percent of graduating geologists are available to the oil and gas industry, the potential supply is shown in Figure J-3.

In Table J-12, projected maximum requirements for geologists (Table J-7) are compared with the number of M.S. and Ph.D. graduates projected to be available to oil and gas companies (Table J-11).

The supply/demand comparisons in Table J-12 indicate that if oil and gas companies continue to hire M.S. and Ph.D. graduates only, a shortage would exist through 1981 at the 40 percent graduation rate, and through 1983 at the 30 percent graduation rate. Realistically, the apparent shortage can be relieved by hiring from the ample supply of B.S. graduates that are available (Table J-10). Even if the demand grew at the 1947-1957 rate of 11.5 percent per year, resulting in 48,000

TABLE J-10

MAXIMUM PROJECTED NUMBERS OF NEW PETROLEUM GEOLOGISTS THROUGH 1985 AT 30 AND 40 PERCENT GRADUATION RATES*

Period	Geology Majors at 30 Schools (8%/Yr)	Projected Nationwide	No. of Grads at 30%/Year of Total	No. of New Pet. Geologists at 66% of New Grads	No. of Grads at 40%/Year of Total	No. of New Pet. Geologists at 66% of New Grads
1978-79	6,413	25,652	7,695	5,078	10,260	6,771
1979-80	6,918	27,672	8,301	5,478	11,068	7,304
1980-81	7,471	29,884	8,965	5,916	11,953	7,888
1981-82	8,068	32,272	9,681	6,389	12,908	8,519
1982-83	8,713	34,852	10,455	6,900	12,940	9,200
1983-84	9,410	37,640	11,292	7,452	15,056	9,936
1984-85	10,162	40,648	12,194	8,048	16,259	10,730

* Includes Bachelor's, Master's, and Ph.D.'s

TABLE J-11

PROJECTED NUMBERS OF NEW PETROLEUM GEOLOGISTS*

Period	M.S. and Ph.D.'s 6%/Yr Increase	Projected Nationwide	No. of Grads at 30%/Year of Total	No. of New Pet. Geologists at 66% of New Grads	No. of Grads at 40%/Year of Total	No. of New Pet. Geologists at 66% of New Grads
1978-79	1,875	7,500	2,250	1,485	3,000	1,980
1979-80	1,999	7,996	2,398	1,582	3,198	2,110
1980-81	2,118	8,472	2,541	1,677	3,388	2,236
1981-82	2,245	8,980	2,694	1,778	3,592	2,370
1982-83	2,379	9,516	2,854	1,883	3,806	2,512
1983-84	2,521	10,084	3,025	1,996	4,033	2,662
1984-85	2,672	10,688	3,206	2,115	4,275	2,821

* Includes Master's and Ph.D.'s

geologists in 1985, the supply of B.S. graduates available to the petroleum industry would be adequate in numbers. This number would be 50 percent more than the maximum number projected by companies responding to the industry questionnaire.

The maximum demand for geologists, as projected by industry survey, was compared with the projected upper limit of wells to be drilled (Table J-7), and resulted in a figure of approximately two wells per year per geologist. Historically, the rate has been two and one-half to three wells per geologist. The current trend indicates that, for numerous reasons, more geological attention is being given per well to exploration and development. It follows that professional geological manpower could be spread thinner, should accelerating activity tighten the supply.

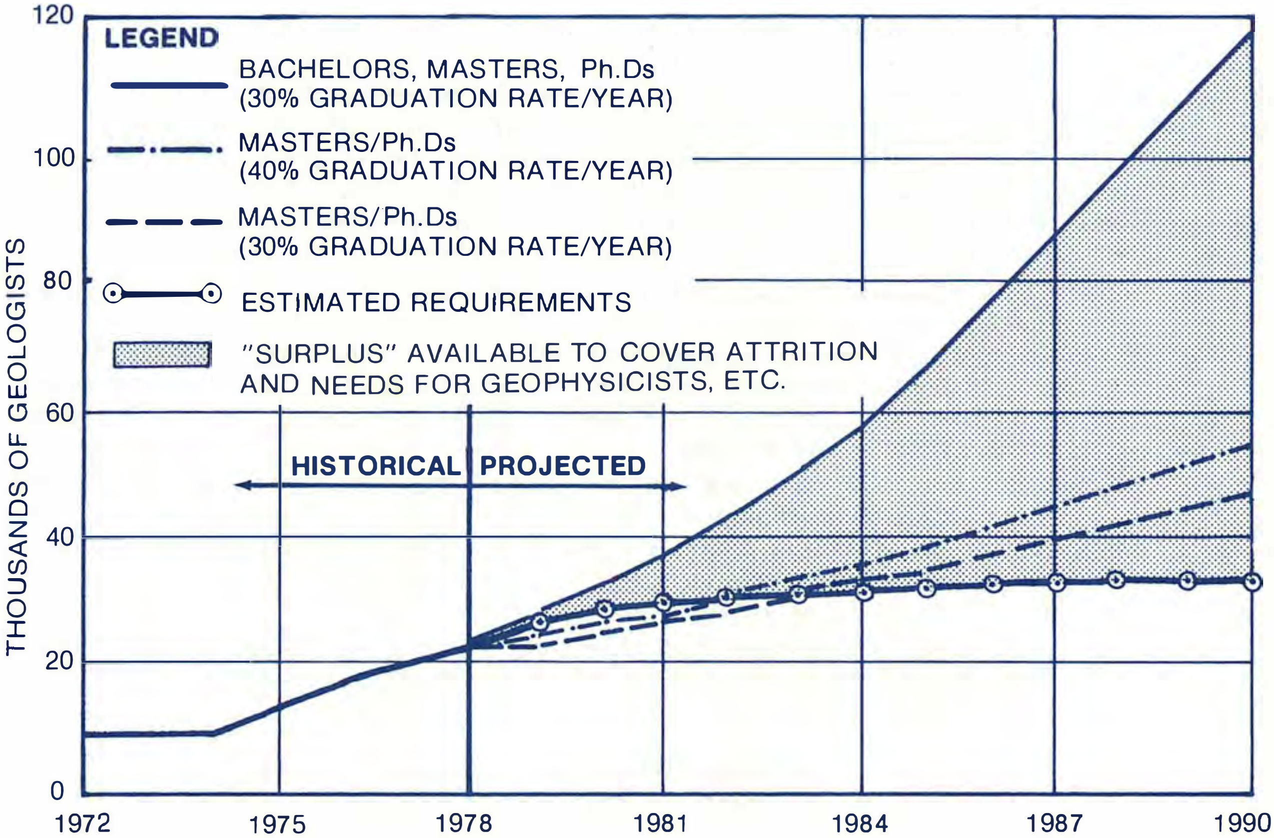


Figure J-3. Domestic Geologic Manpower with Academic Supply Additions.

TABLE J-12

PROJECTED MAXIMUM GEOLOGISTS REQUIRED AND M.S./Ph.D. AVAILABILITY

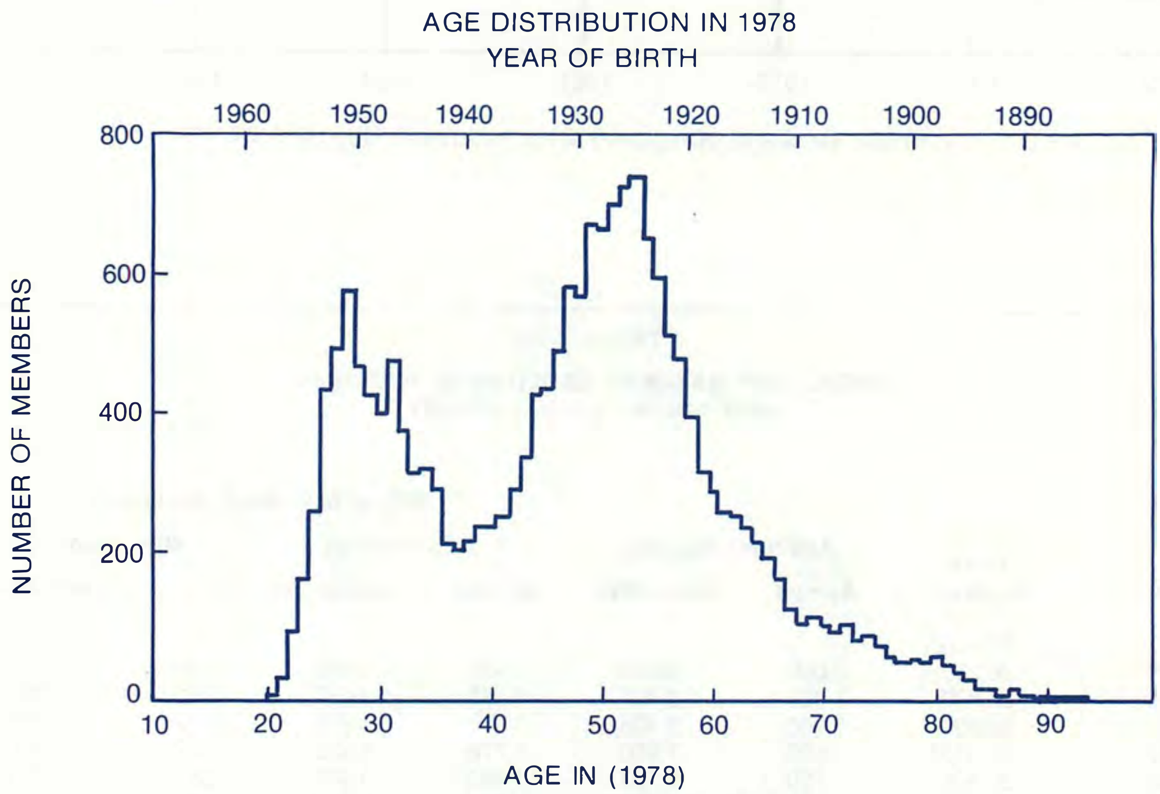
				66% of M.S./Ph.D. Graduates			
		Additions Needed §		30% Grad/Yr.		40% Grad/Yr.	
Year	Total Required	Annual	Cumulative	Annual	Cumulative	Annual	Cumulative
1978	22,400*						
1979	26,200	3,800	3,800	1,485	1,485	1,980	1,980
1980	28,100	1,900	5,700	1,582	3,067	2,110	4,090
1981	29,800	1,700	7,400	1,677	4,744	2,236	6,326
1982	30,350†	550	7,950	1,778	6,522	2,370	8,696
1983	30,900†	550	8,500	1,883	8,405	2,512	11,208
1984	31,450†	550	9,050	1,996	10,401	2,662	13,870
1985	32,000	550	9,600	2,115	12,516	2,821	16,691
1990	34,400	480	12,000				

* From Table J-7.
† Interpolated.
§ After filling vacancies caused by attrition.

The level of experience in a rapidly expanding population of professional geologists is of concern to the industry. Some experienced talent might be recruited from among government employees, academia, American citizen repatriots, and from the minerals industry. The bulk of qualified professionals, however, will come from intensive industry training programs for recent graduates. The experience factor will be further aggravated by the number of geologists who will retire during the next five to 15 years, as indicated by the American Association of Petroleum Geologists age distribution shown in Figure J-4. This will necessitate moving younger men up rapidly, further emphasizing the need for training programs in both technology and management.

In summary, it is indicated that there will be a shortage of geologists until 1982, if oil and gas companies continue the practice of hiring only M.S. and Ph.D. graduates. However, the supply of available B.S. graduates will be more than adequate to fill any needs. The current ratio of approximately two wells per year per geologist would result in the manning of 59,600 wells in 1981, 64,000 in 1985, and 69,000 in 1990, with the maximum projected geological manpower. These numbers are near the projected upper limit of possible wells, as presented in Chapter One. A geological growth rate of 11.5 percent per year, achieved during the 1947-1957 period, is considered possible. Starting with 22,400 in 1978, such a growth would result in 31,000 geologists in 1981 and 48,000 in 1985. At 2 to 2.5 wells per geologist, 62,000 to 77,500 wells could be drilled in 1981 and 96,000 to 120,000 could be drilled in 1985. Geological manpower is, therefore, not expected to be a constraint to accelerating exploration and development activity.

The experience level of professional geological personnel is a concern (Figure J-4), but this will be managed through intensive training programs.



SOURCE: *AAPG BULLETIN*, June 1978, Vol. 62, No. 6, p. 1064.

Figure J-4. American Association of Petroleum Geologists Membership.

Engineers

Engineers employed by exploration and production companies, supporting service and supply companies, and consulting firms may have been formally educated in any one of the major engineering disciplines. The greater portion, however, received B.S. or M.S. degrees in petroleum, chemical, mechanical, or civil engineering. Producers generally prefer to hire petroleum engineers, but must have civil engineers to design and build roads and structures. Electrical engineers predominate in well logging services, chemical engineers in drilling fluid services, and mechanical engineers in other services such as drilling, cementing, and well servicing. All service companies prefer to hire petroleum engineers as sales representatives who will be in contact with production companies.

Production companies generally refer to their entire engineering staff as petroleum engineers, but individual jobs have more descriptive titles. These are described in the Society of Petroleum Engineers (SPE) of AIME report of *Survey Number 2* of the SPE Engineering Manpower Committee, May 1979.[1]

- Geological engineers give direct geological support to drilling and development activities on a field scale, a job performed by production geologists in some companies.
- Reservoir engineers estimate recoverable oil and gas reserves, predict reservoir performance, recommend optimum development and production strategies, and design and recommend enhanced recovery techniques. These are done by the application of mathematical models to simulate the performance of oil and gas reservoirs, and involves the physical and chemical properties, including phase behavior of fluids flowing through porous media.
- Drilling engineers provide engineering support for drilling operations, including rig selection, optimum drilling techniques, design of drilling fluid programs, casing, tubing, and cementing programs.
- Production engineers design well completions, recompletions, remedial (workover) operations, and stimulation, analyze well performance, and select and design artificial lift methods. This specialty is usually called subsurface production engineering.
- Petrophysical-logging engineers, usually employed by wireline service and core analysis companies, measure and derive the fluid and rock properties of reservoir rocks through laboratory measurements and interpretations of electrical, radioactivity, and acoustical wireline logs.
- Field engineers for surface facilities specify and design systems for control, treatment, measurement, and transportation of produced hydrocarbons. This includes oil, gas, and water separation, produced water treatment and disposal, field liquid and gas handling, and transportation. This specialty is usually called surface production engineering.
- Process and chemical engineers for surface facilities specify and design oil and gas processes, including field gas processing, chemical removal of water from oil, filtration systems and corrosion control by chemical treatment, cathodic protection, and material selection. Gas plant processing design for extraction and fractionation of heavy hydrocarbons from natural gas is usually referred to as gas engineering.
- Civil engineers perform platform designs and construction supervision for drilling and production facilities in the marine environment. Many are employed by offshore construction contractors.
- Other engineering specialists design and operate computer production control systems for automatically metering production, production testing, and production control. Others design and operate subsea production systems, and are employed in environmental control, safety surveillance, and training of others. Engineers also perform economic analyses, plan budgets and activities, prepare forecasts, and participate in government relations and intercompany liaison and negotiations.

The 1979 SPE survey was designed by its Engineering Manpower Committee to provide supply and demand information for petroleum engineers: historically, from 1974 through 1978, and with projected high and low level requirements for 1979 through 1983. The intent was to assess demand by obtaining a reasonably complete response from the major producing companies engaged in drilling and production operations, plus a sampling of independent producers, gas transmission

[1]*Supply and Demand Survey of Engineering Manpower Employed in Drilling and Production Operations in the United States Oil and Gas Industry Job Market, Survey Number 2*, SPE Engineering Manpower Committee, Society of Petroleum Engineers of AIME, May 1979.

companies, service and drilling companies, and certain government agencies expected to employ petroleum related engineers. In his analysis of the SPE survey, Calhoun presented demand source data from the survey as shown in Table J-13.[2]

While the operations of the responding companies represent a large portion of total U.S. activities, there was no valid way to present an industry total of the number of engineers employed in drilling and production.

Noticeably absent from the survey are data on independent consultants and employees of consulting firms. The May 1979 issue of the *Journal of Petroleum Technology*, Page 586, showed that in response to a salary survey of SPE members, about 10 percent indicated that they are in the consultant category. This should not influence the projected demand for new graduates, because very few are expected to enter consulting practice directly out of college.

Engineering supply information was sought from all U.S. universities that offer petroleum engineering degree programs. This excluded universities offering options in petroleum engineering by other engineering departments. Calhoun reported that 18 (85.7 percent) of the 21 universities surveyed responded.

TABLE J-13
ENGINEER POPULATION OF RESPONDING ORGANIZATIONS—1978

	Surveyed		Number of Engineers		
	Number	**% Response**	**Total**	**P.E. Grads**	**% P.E.**
Majors	26	77	6,790	2,628	39
Independents	69	36	525	348	66
Gas Companies	25	28	103	63	61
Service Companies	20	45	1,982	227	11
Government	7	14	4	3	75
Total			**9,404**	**3,269**	**35**

The SPE Engineering Manpower Committee *Survey Number 2*, May 1979, was published without interpretative comments. Table J-14 shows data extracted from Tables 1 and 2 of the SPE report, which represent the aggregated year end number, both historical and projected, of engineers employed by respondents.

Data for the total number of engineers employed show that from 1974 to 1978 the majors increased 32 percent, independents 82 percent, gas companies 43 percent, and service companies (including drilling contractors) 60 percent. The percentage of engineers with petroleum engineering B.S./M.S. degrees declined, indicating a growing shortage in their availability. From 1974 to 1978, the number of wells drilled increased 48 percent and feet drilled increased 58 percent, showing a correlation between drilling activity and engineering requirements.

The high level engineering manpower requirements of majors are projected to increase by 15 percent in 1981 over 1978, while independents project 31 percent, gas companies 15 percent, and service companies 38 percent. These high level projections correspond with the Outlook upper limit of projected possible range of activity, which shows 19 percent more wells and 21 percent more feet to be drilled in 1981 than in 1978.

Table J-15, which was extracted from Table 3 of the SPE report, shows historical and projected on-campus hiring of B.S./M.S. engineers in all disciplines. Table J-16, extracted from Table 5 of the SPE report, shows the same data for on-campus hiring of B.S./M.S. petroleum engineers.

Table J-15 indicates that the majors hired the desired number of total engineers in 1978. The 1979 high level demand is projected to peak at 13 percent above that of 1978, and then decline to

[2]Calhoun, John C., Jr., *Analysis of Society of Petroleum Engineers Engineering Manpower Survey*, Houston, Texas, June 7, 1979 (unpublished).

TABLE J-14

YEAR-END NUMBER OF ENGINEERS EMPLOYED IN DRILLING AND PRODUCTION

		Historical			Projected		
		1974	1978		1979	1981	1983
Majors	Total	5,157	6,790	High Level	7,429	7,810	8,038
				Low Level	7,048	7,213	7,328
	P.E. B.S./M.S.	2,245	2,628				
Independents	Total	288	525	High Level	584	688	775
				Low Level	508	523	538
	P.E. B.S./M.S.	219	348				
Gas Companies	Total	72	103	High Level	107	118	131
				Low Level	94	100	107
	P.E. B.S./M.S.	55	63				
Service Companies	Total	1,239	1,982	High Level	2,303	2,736	3,393
				Low Level	2,084	2,536	2,998
	P.E. B.S./M.S.	171	227				

TABLE J-15

HIRING OF ON-CAMPUS B.S./M.S. ENGINEERS (ALL DISCIPLINES) BY RESPONDING COMPANIES

		Historical			Projected		
		1974	1978		1979	1981	1983
Majors	Desired	557	921	High Level	1,041	908	921
	Hired	548	958	Low Level	902	738	743
Independents	Desired	6	12	High Level	19	19	20
	Hired	5	11	Low Level	16	9	7
Gas Companies	Desired	14	12	High Level	9	9	11
	Hired	3	8	Low Level	5	4	4
Service Companies	Desired	249	434	High Level	435	479	585
	Hired	207	393	Low Level	345	392	486
Total	**Desired**	**826**	**1,379**	**High Level**	**1,504**	**1,415**	**1,537**
	Hired	**763**	**1,370**	**Low Level**	**1,268**	**1,143**	**1,240**

the 1978 level by 1983. Low level demand would drop by 20 percent in 1981 and flatten. Independents' and gas companies' desires vary considerably in percentage and are not significant in the total demand. Service companies' 1978 employment was about 10 percent below desires. These companies see the high level demand rising 10 percent by 1981 and 35 percent by 1983. Low level demand would be flat through 1981 and climb about 25 percent in 1983.

Table J-16, compared with Table J-15, indicates that majors intended that their on-campus hiring include 50 percent B.S./M.S. petroleum engineers, but results showed only 38 percent. Service companies hired only 10 percent of the B.S./M.S. petroleum engineers desired. This excess in demand for petroleum engineers was reflected in the average salary offer, which reached $1,818 per month, as reported in the *Journal of Petroleum Technology*, August 1979, Page 993. This was the highest reported average salary for any discipline in the U.S. graduating class of 1979. The high level projection of majors' on-campus desired petroleum engineering hires would be about the same in 1979 as in 1978, and would decline about 11 percent by 1983. The low level demand would decline 17 percent by 1983 from the 1978 number hired. Service companies would continue the high level demand for petroleum engineers for both low and high level projections, the high level in 1983 being 34 percent above 1978 desires and 13 times the number hired.

TABLE J-16

HIRING OF ON-CAMPUS B.S./M.S. PETROLEUM ENGINEERS BY RESPONDING COMPANIES

		Historical			Projected				
		1974	1978		1979	1980	1981	1982	1983
Majors	Desired	294	459	High Level	464	428	415	414	408
	Hired	218	365	Low Level	374	328	312	310	304
Independents	Desired	4	9	High Level	15	11	15	13	16
	Hired	4	6	Low Level	12	4	7	3	5
Gas Companies	Desired	3	5	High Level	11	8	11	10	11
	Hired	2	3	Low Level	6	3	5	5	5
Service Companies	Desired	71	106	High Level	109	114	117	128	142
	Hired	8	11	Low Level	85	91	95	106	120
Total	**Desired**	**372**	**579**	**High Level**	**599**	**561**	**558**	**565**	**577**
	Hired	**232**	**385**	**Low Level**	**457**	**426**	**419**	**414**	**434**

A significant and growing factor in engineering personnel recruitment is the practice of off-campus hiring. Comparing off-campus hiring (in Table 4 of the SPE report) with on-campus hiring, showed that in 1978, 17 percent of all of the majors' new hires were off campus, as were 27 percent of service and drilling companies' and 92 percent of the independents' new hires. The significant percentage of off-campus hires indicates a large pool of mobile engineering personnel moving between companies, including consultant organizations. The extremely high percentage of off-campus hiring by independents indicates their need for immediate performance of a new hire, without the delays for training and experience.

Table J-17, which was extracted from Table 7 of the SPE Manpower Committee report, represents a compilation of historical and projected B.S./M.S. petroleum engineer graduates, data for which was received from responding universities.

In Table J-18, the high level numbers desired were calculated by multiplying the numbers desired (as presented in Table J-16) by the ratio of U.S. job entries (by category) in 1978 to the number of petroleum engineers hired by responding companies. For example, 414 U.S. entries hired by majors in 1978 divided by 365 hired by responding majors gives a factor of 1.148. This multiplied by 464 high level desired by responding majors in 1979 gives the 532 total high level desired by majors shown in Table J-18.

Table J-18 indicates that the projected supply of B.S./M.S. petroleum engineers would still be tight in 1979 if the service and drilling companies continued hiring goals at the projected high level. By 1980, all high level demand projections would be met and a surplus could develop in 1981.

Chapman, commenting on the SPE survey, pointed out that the results for the total number of engineers employed in drilling and production are low, since there are many hundreds of small companies and independents who were not covered. The engineering supply study was focused on petroleum engineers, because the number of non-petroleum engineers entering this industry each year is extremely small when compared with the total population of engineers in the United States. In addition to normal manpower losses due to death and retirement, losses from the engineering manpower pool are due to the significant number moving into other oil and gas company activities

TABLE J-17

B.S./M.S. PETROLEUM ENGINEER GRADUATES FROM RESPONDING UNIVERSITIES

		Historical		Projected				
		1974	1978	1979	1980	1981	1982	1983
B.S. P.E. Grads	Total	313	536	793	856	917	952	843
	U.S. Jobs	274	508	742	793	843	876	774
M.S. P.E. Grads	Total	44	47	66	76	91	100	113
	U.S. Jobs	32	31	47	59	74	80	92
Total B.S./M.S. P.E. Grads	**Total**	**357**	**583**	**859**	**932**	**1,008**	**1,052**	**956**
	U.S. Jobs	**306**	**539**	**789**	**852**	**917**	**956**	**866**
Job Entry Categories								
Majors		191	419					
Independents		7	42					
Gas Companies		5	10					
Service Companies		21	23					
Government		0	4					
Other		11	13					

TABLE J-18

RESPONDING UNIVERSITIES PROJECTED AVAILABLE B.S./M.S. PETROLEUM ENGINEERS VERSUS CALCULATED HIGH LEVEL DEMAND

	U.S. Job Entries	High Level Projected Numbers Desired				
	1978	1979	1980	1981	1982	1983
Majors	419	532	491	476	475	468
Independents	42	105	77	105	91	112
Gas Companies	10	37	27	37	33	37
Service Companies	23	228	238	245	267	297
Total Oil & Gas	**494**	**902**	**833**	**863**	**866**	**914**
Government Agencies	4					
Others	13					
Grand Total	**511**					
Available to U.S. Job Entry	539	789	852	917	956	866
Supply/Demand Ratio		0.87	1.02	1.06	1.10	0.95

as well as into other industries and government. Engineering is the prime source of manpower for operations management and for many other intra-company assignments such as research and development.[3] Calhoun estimated that this attrition rate for all engineers in drilling and production activities is between 4.6 percent and 9.3 percent per year.[4]

Covey commented from the viewpoint of the small company, stating that his technical staff has more than doubled in two and a half years. In recruiting, he looks for engineers with some experience and would not hire a new graduate from any discipline other than petroleum engineering.[5]

Leon remarked, as a representative of the drilling and production service industry, that their main requirements for engineering skills are in mechanical, chemical, and electrical engineering. Seventy-four percent of his company's graduates are in engineering positions, 18 percent in management, and eight percent in sales. Almost all personnel now moving into management have an engineering background, and first choice in recruiting is for graduates in petroleum engineering.[6]

Von Gonten, reporting on engineering education, stated that the large number of petroleum engineers graduating from universities is of concern to both educators and industry personnel. It is important that supply and demand be matched so that no large surplus occurs. The rapid growth in the number of petroleum engineering students (two fold in five years) is causing serious problems in the staffing of university petroleum engineering departments.[7]

Dr. Earnest F. Gloyna, Dean of the College of Engineering, University of Texas at Austin, reported to the National Petroleum Council that historically engineering enrollment is directly related, time delayed, to economic cycles. Currently, academic institutions are making an intense effort to operate on a good business basis. A lack of interested and qualified students is not a constraint to the expanding capacity of engineering schools, as these schools will be at capacity in the fall of 1979, with many qualified applicants turned away. Enrollment builds up rapidly at the third year level because of transfers from two-year colleges, as students perceive the desirability of an engineering career. While engineering and business school enrollment is increasing, there is a significant decrease in enrollment in the humanities. There is a reluctance, however, to request funds for expansion of capacity because of the cyclic enrollment history. Educational institutions that wish to expand their science and engineering departments have a great need for more funds, with general funds, building funds, and faculty funds being of equal importance. Strong industry support was an important factor in the ability of engineering schools to expand output to meet recent demands.

Of serious concern to engineering schools is the declining enrollment in some graduate programs, which is the source of faculty personnel and will affect the quality of future engineering education. High starting salaries offered to B.S. graduates, and insufficient funds for both faculty and student support contribute to low graduate enrollment, particularly in petroleum engineering. Dr. Gloyna suggested that if the Department of Energy is to help in engineering education, support should be similar to the Defense Department's block grant model, which over a period of several years has built up laboratory facilities and supported both faculty and students in graduate programs.

The continuing education of engineers is vital if the industry is to maintain the competence and performance required in this complex and varied business. Chapman described the kinds of continuing education as: introduction of new engineering knowledge; maintenance of technical

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[3] Chapman, Peter F., *Introductory Remarks*, SPE Manpower Conference, Houston, Texas, June 7, 1979 (unpublished).

[4] See footnote 2.

[5] Covey, F. D., *Petroleum Engineering Manpower Requirements as Viewed by the Independent Sector*, Houston, Texas, June 7, 1979 (unpublished).

[6] Leon, Leonard, *Remarks Regarding the Service Segment of the Industry*, Houston, Texas, June 7, 1979 (unpublished).

[7] Von Gonten, W.D., *Undergraduate and Graduate Petroleum Engineering Education in the United States*, Houston, Texas, June 7, 1979 (unpublished).

competence; introduction of industrial applications; switching of disciplines; and working on degree programs, interdisciplinary exchange, and administrative skills.

The major oil and gas companies conduct extensive in-house training programs to give early competence in specialized fields, such as reservoir engineering, drilling engineering, production engineering, and gas engineering. Similar short courses are offered by several universities, and a growing number of commercial programs are being offered by independent consultants. The Society of Petroleum Engineers is active in the field with technical seminars, workshops, and video tape programs.[8]

Summary

The rapid increase in demand for engineers in drilling and production operations resulted in a shortage of petroleum engineering graduates, which apparently peaked in 1979. The demand was met by hiring graduates of other disciplines and by hiring off-campus. The growth of enrollment in petroleum engineering schools is expected to produce enough graduates to equal or exceed the number in demand during the 1981-1983 period. The two greatest concerns of petroleum engineering schools are that present growth rates will produce a significant surplus of B.S. graduates, and that insufficient enrollment in graduate programs will result in a shortage of qualified faculty in the next decade.

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[8] Chapman, Peter F., *Continuing Education Programs, Past, Present, and Future*, SPE Paper 6030, Society of Petroleum Engineers of AIME, October 1976.