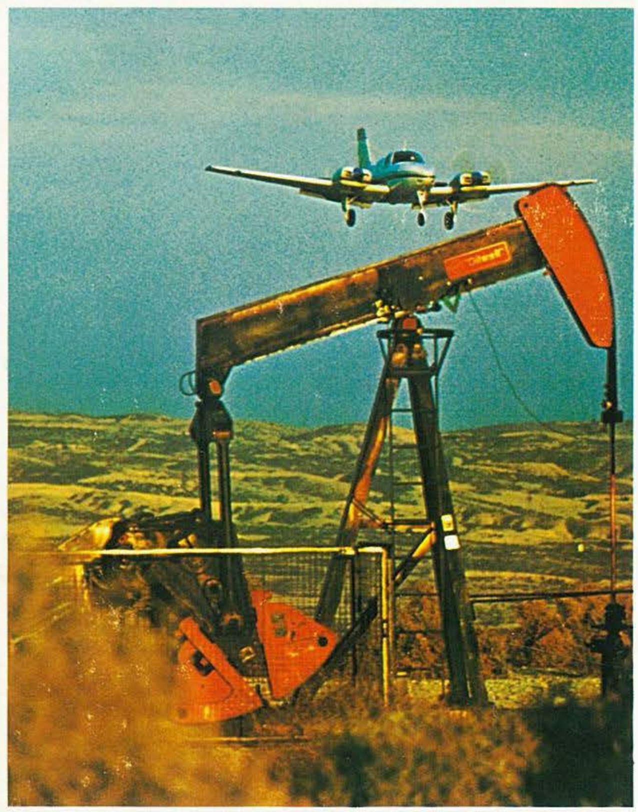
Availability of Materials, Manpower and Equipment for the Exploration, Drilling and Production of Oil--1974-1976



National Petroleum Council
September 1974

Availability of Materials, Manpower and Equipment for the Exploration, Drilling and Production of Oil--1974-1976

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National Petroleum Council
September 1974

NATIONAL PETROLEUM COUNCIL
H. A. True, Jr., Chairman/Robert G. Dunlop, Vice Chairman/Vincent M. Brown, Executive Director

September 10, 1974

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 *Availability of Materials, Manpower, and Equipment for the Exploration, Drilling and Production of Oil--1974-1976* as approved by the Council at its meeting on September 10, 1974. This full report of the Council contains the detailed supporting information and data to the Summary Report presented to you at the meeting of the Council.

On December 21, 1973, the Assistant Secretary of the Interior requested the Council to undertake this study, stating:

> The Department of the Interior has an urgent need to know the availability of materials, manpower and equipment necessary for the exploration and production of oil during the next two years. Any shortages of materials, manpower or equipment needed for these tasks should indicate the probable limitation on drilling activity. The duration and causes of such shortages, together with any possible measures to alleviate them, should be set forth.

In response to this request, the NPC Committee on Emergency Preparedness, chaired by Carrol M. Bennett, Chairman of the Board of Texas Pacific Oil Company, Inc., appointed a Subcommittee on Materials and Manpower Requirements for Petroleum Exploration, Drilling and Production under the chairmanship of Kenneth E. Hill, Executive Vice President, Corporate Finance, Blyth Eastman Dillon & Co., Inc.

In the course of the study since December 1973, the Committee has continually revised its estimates of the short-term outlook for rig availability and activity. Current (September 1974) data continue to reinforce our optimism. It is therefore possible that actual experience could be better than that shown in this report. A combination of factors could contribute to this improved outlook: fewer than expected rigs exported; prompt resolution of problems concerning repatriation of previously exported rigs both from Canada and overseas; and the possible use of larger "workover rigs" for drilling operations. Achievement of increased levels of rig activity will be dependent upon changes in the relative economic attractiveness of domestic *versus* foreign rig registry as well as the total financial capacity of the petroleum industry and the responsiveness of suppliers to bid for resources. Additionally, if a slowdown of worldwide economic growth occurs during the projection period, some of the critical material availability constraints discussed in this report--especially for steel--may be eased.

The National Petroleum Council sincerely hopes that this study will be of benefit to you and the Government in understanding the difficulties and problems associated with the current rapid escalation of domestic petroleum activities.

Respectfully submitted,

H. A. True, Jr.
Chairman

Honorable Rogers C. B. Morton
Secretary of the Interior
Washington, D.C.

AVAILABILITY OF

MATERIALS, MANPOWER AND EQUIPMENT

FOR THE

EXPLORATION, DRILLING AND PRODUCTION

OF OIL--1974-1976

A Report of the

National Petroleum Council's
Committee on Emergency Preparedness
Carroll M. Bennett, Chairman

and the

Subcommittee on Materials & Manpower
Requirements for Petroleum Exploration,
Drilling & Production
Kenneth E. Hill, Chairman

NATIONAL PETROLEUM COUNCIL

H. A. True, Jr., *Chairman*
Robert G. Dunlop, *Vice Chairman*
Vincent M. Brown, *Executive Director*

Industry Advisory Council

to the

U.S. DEPARTMENT OF THE INTERIOR

Rogers C. B. Morton, *Secretary*
Jack W. Carlson, *Asst. Secretary for Energy and Minerals*

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INTRODUCTION

The substantial dependence of the United States on petroleum imports has major national security implications. Recognizing these security problems and the need for an effective emergency preparedness plan, the Secretary of the Interior on December 5, 1972, requested the National Petroleum Council to undertake a "comprehensive study and analysis of possible emergency supplements to, or alternatives for imported oil, natural gas liquids and products in the event of interruptions to current levels of imports of these energy supplies." In response to this request, the National Petroleum Council's Committee on Emergency Preparedness issued on July 24, 1973, *Emergency Preparedness for Interruption of Petroleum Imports into the United States--An Interim Report*, followed by *Supplemental Interim Report* on November 15, 1973 and *Short-Term U.S. Petroleum Outlook--A Reappraisal* on February 26, 1974.

The Secretary of the Interior supplemented his original study request on December 21, 1973 with the statement:

> The Department of the Interior has an urgent need to know the availability of materials, manpower and equipment necessary for the exploration and production of oil during the next two years. Any shortages of materials, manpower or equipment needed for these tasks should indicate the probable limitation on drilling activity. The duration and causes of such shortages, together with any possible measures to alleviate them, should be set forth.

To address this request of the Secretary, the Committee on Emergency Preparedness appointed a Subcommittee on Materials and Manpower Requirements for Petroleum Exploration, Drilling and Production. This study has been conducted by six task groups under the Subcommittee--Outlook, Exploration and Drilling, Tubular Steel, Production, Well Servicing and Gas Processing Plants. In addition to Council member representation, a number of individuals have participated from manufacturers and suppliers of oilfield equipment, from drilling and construction contractors, and from service companies. This representation assured the consideration of the best information available on the present materials and manpower situation. (See Appendix A for Request Letters and Appendix B for Committee Rosters.)

SCOPE OF THE STUDY AND BASIC ASSUMPTIONS

The purpose of this study was to investigate the availability of materials, manpower and equipment necessary for the exploration, drilling and production functions of the petroleum industry to expand activities to lessen U.S. dependence upon petroleum imports. The scope and basic assumptions reflected in the report are as follows:

- In view of the long lead time for a number of significant equipment items, the Department of the Interior approved extension of the study to include 1976. The outlook for expansion of activities to 1980 and 1985 is also appraised.

- It is assumed there will be adequate economic incentives for oil and gas producers to expand drilling and production activities within the limitation of available materials, equipment and manpower during the years ahead.

- No estimates are made of possible quantitative effects of any changes in prices and tax laws on the level of activities. However, the qualitative effects of government policies are discussed.

- It is assumed that there will be incentives for the orderly expansion of production capacity for oilfield equipment manufacturers, contractors and service companies and that financing will not be a constraint.

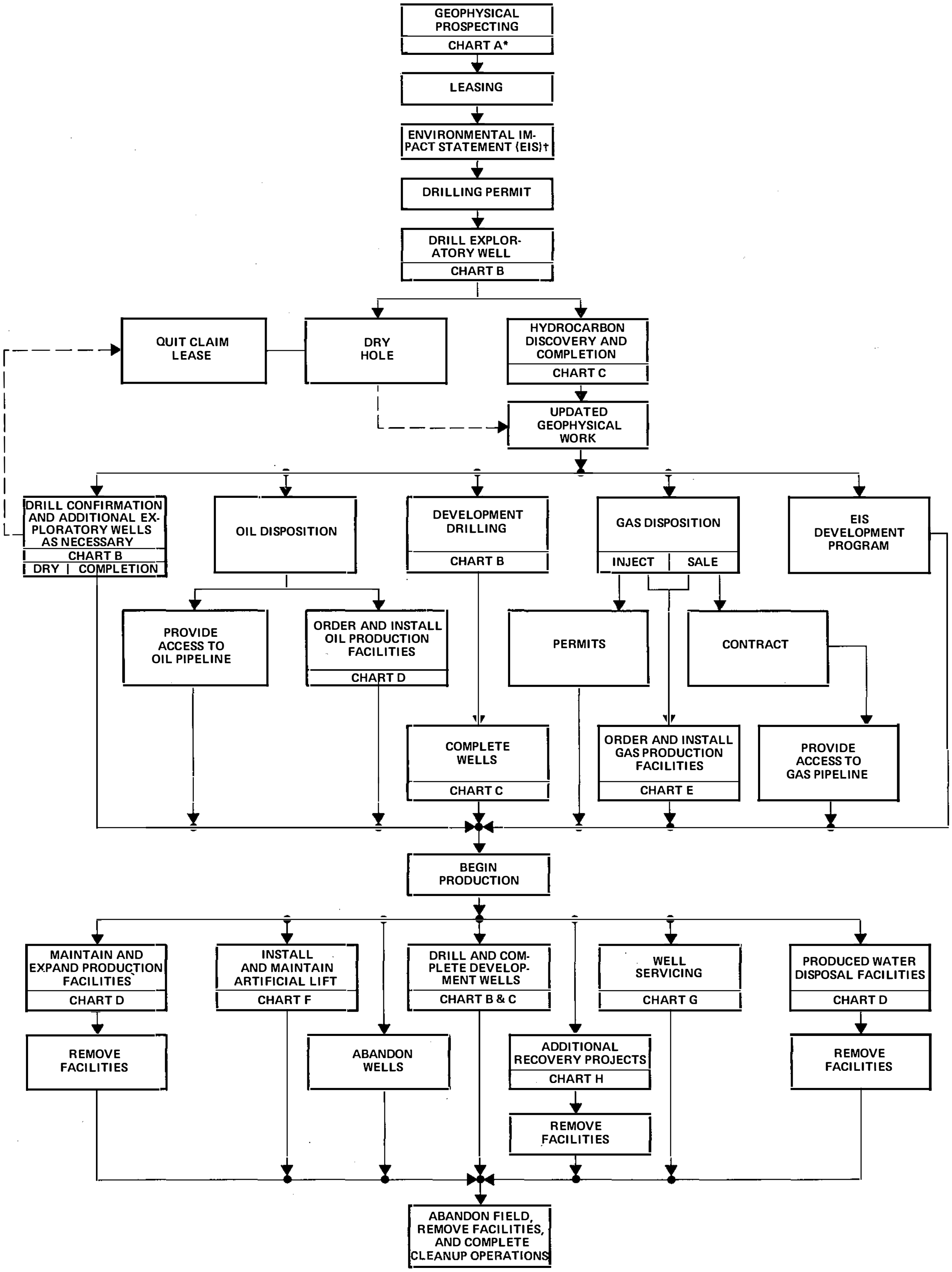
- No forecasts are made of the oil and gas producing rates which will result from the activity levels projected in this report.

OVERVIEW OF EXPLORATION AND PRODUCTION FUNCTIONS

The many facets of the oil and gas exploration and production business are interrelated and interdependent and do not function separately. This is illustrated in Figure 1 (see Appendix C, Figures 9-16 for more detail) which shows the flow of activities and the principal materials, equipment and services required from the time exploration starts through development of a commercial petroleum deposit to field abandonment. From this flow diagram, it is apparent that the exploration and production segment of the oil and gas industry is a complex, integrated matrix. The industry is made up of thousands of producers, served by hundreds of manufacturers, suppliers and service contractors, many of whom depend entirely upon oil and gas producers for their livelihood.

Exploration does not stop with the completion of a discovery well since confirmation and extension wells are necessary to determine if the reservoir is of commercial quality and quantity. While confirmation drilling is still in progress, production facilities will usually be installed 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 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.

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



* *"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 1. Simplified Flow Diagram Showing Operations Necessary for Discovery, Production and Abandonment of an Oilfield.

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 disposed of by injection into the ground or discharged into surface waters when legally and environmentally acceptable.

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. 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 extraneous materials such as steam or chemicals.

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 and injection wells drilled. As wells become uneconomical to produce, they must be plugged with cement, casing pulled, surface equipment removed and the surface area cleaned up in an acceptable manner.

SUMMARY AND RECOMMENDATIONS

SUMMARY

The National Petroleum Council submits the following findings on U.S. oil operations:

- Over the past decade, the depressed economic climate in the oil and gas producing industry resulted in a decline of 24 percent in footage drilled, and about 20 percent in the number of available rigs. The service industry, however, did not deteriorate during this period because of the more intensive application of new technology to oil and gas reservoirs and the continuing need for workover of existing producing wells.

- Drilling activity in 1974 is projected to increase 15 percent over 1973 to about 160 million feet (31,800 wells). While workable drilling rigs are now approaching maximum utilization rates, their efficiencies have been reduced by delays in tubular goods availability, logistical and manpower problems. Oil country tubular goods (OCTG), particularly casing, has been a critical constraint during much of 1974.

- Oil country tubular goods have been in short supply due primarily to the need for each operator to develop an individual working inventory, after the steel companies, starting in the third-quarter of 1973, changed their prior practice of providing inventories for the industry near the point of consumption. The change in inventory practice from a few large and strategically placed stocks has created many smaller user and distributor inventories. Even though U.S. mill shipments of these products for domestic use are expected to increase 17 percent over 1973, a disruptive effect on the tubular goods supply will be felt until inventories are stabilized. At this time, although pipe is still in short supply, workable rigs are now being used at maximum rates. Therefore, in the latter part of 1974, rigs will probably become the more important constraint, although the rig/pipe availability system is so closely balanced that one or the other may be a constraint to an individual operator.

- During the current period of tight supply, shipments of oil country tubular goods from U.S. mills to domestic users and distributors are being made to a large extent on a purchase history basis. While most users are unable to buy all of their requirements, those independents who have no domestic casing purchase history are particularly hard hit. This situation can be resolved through cooperation by the steel industry, the government and all sectors of the oil producing industry without resorting to allocation programs.

- Drilling activity is projected to increase in 1975 to 172 million feet and 33,600 wells, and in 1976 to 179 million feet and 34,500 wells. The anticipated growth rate of 10 percent in 1975 and 5 percent in 1976 in U.S. oil country tubular goods mill production should maintain the supply near that required for optimum use of workable drilling rigs after 1974. There may still be spot shortages of high-strength casing and of other specific items in 1975, but the possible effect is difficult to quantify. These projections of drilling activity could be on the low side, considering the industry's record of rapid response to improving economic conditions. More rigs may be available than projected due to the potential effect of fewer rigs exported than expected and by rigs returning from overseas and imported from Canada.

- The long-range outlook for drilling activity indicates the need for rapid expansion of drilling equipment manufacturing capacity. For example, the highest drilling rate case (Case I) of the NPC 1972 *U.S. Energy Outlook* study, assumed a drilling effort of about 250 million feet in 1980 and nearly 300 million feet in 1985.* This is believed to be an attainable goal. If exports of newly assembled rigs were to continue at the historic rate of approximately 50 percent, new rig manufacturing would have to grow at an improbable 25 percent annual rate to reach these projected drilling levels by 1980. A more realistic expectation would be a growth of 10-15 percent. About 11 percent annually would provide sufficient rigs to reach the Case I rate by 1985. Corresponding expansion in tubular goods mill production and in the well servicing industry would be necessary for maximum utilization of these new rigs. Based on the projected output of offshore production platforms through 1976, annual expansion rates of 20 percent are necessary to reach Case I projections by 1980, or 12 percent by 1985. Furthermore, there will be significant increases in steel tonnage per platform because the additional drilling will be in deeper water and harsher environments.

- Basic steel output and many other commodities required for drilling and producing activities are in short supply, but none is expected to seriously restrain drilling activity. This outlook could change if there are serious disruptions, such as strikes.

- Manpower is not believed to be a critical constraint in most areas for drilling, well servicing and equipment manufacture and utilization. However, manpower problems on previously inactive rigs mobilized during 1974 have contributed to lowering the efficiency of the drilling indus-

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* NPC, *U.S. Energy Outlook--A Report of the National Petroleum Council's Committee on U.S. Energy Outlook*, Washington, D.C., December 1972. Hereinafter referred to as *U.S. Energy Outlook*.

try. With the rapid expansion expected in the next few years, qualified manpower must be attracted to the industry so that manning will not be a limiting factor and to this end, training programs must be accelerated.

- This report assumes that adequate capital will be available to the petroleum industry to expand exploration and drilling along with available equipment and manpower. It should be noted, however, that the capital required will be of a magnitude unprecedented in the history of the industry. However, capital formation for all segments of the petroleum and service industry should be adequate if free market prices for oil and gas are allowed to generate the profits necessary to assure steady growth over the long term.

- Capital investment decisions must be made by manufacturers and service companies by late 1974 if supplies and services are to be significantly increased by 1976 and thereafter. Current uncertainties regarding national energy policies tend to delay the making of these decisions.

RECOMMENDATIONS

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

Develop and Implement National Energy Policies Designed to Increase the Nation's Domestic Energy Supplies

The essence of these policies has been enunciated by the NPC *U.S. Energy Outlook* study in the following suggestions.

- Assure adequate supplies of *secure* sources of energy.

- Promote efficiency and conservation in all energy operation and uses.

- Preserve the environment in the production and use of energy.

A clear mandate for a national dedication to the above policies is needed to assure the expansion of exploration, drilling and production required by private industry to reduce U.S. dependence on foreign oil sources.

Allow Free Market Forces to Determine Prices for Oil and Gas in the United States

Adequate capital must be generated to expand the exploration, producing and servicing sectors of the industry at the projected rates. Any action of government that impairs profits by reducing prices or increasing taxes can critically impede the generation of the capital needed for such expansion.

Expand Steelmaking Capacity

Shortages of steel will hinder rapid expansion of nearly all facets of the drilling and service industry. Now that price controls on steel have ended, it is believed the steel industry will increase the production of materials used by the petroleum industry. Market clearing price levels will tend to equalize the present U.S. export-import imbalances, though the world steel industry is expected to be in a tight supply/demand position for some years.

Expand Availability of Drilling and Producing Equipment

Drilling rig construction capability should expand at least 11 percent per year from 1977 through 1985 to attain the NPC Case I drilling rate of near 300 million feet per year in 1985. Furthermore, manufacturing facilities for equipment necessary for well completion and production maintenance must expand to keep pace with the growing need for well servicing. Offshore production platform construction yard capacity should increase at least 12 percent per year during this period. Operators of equipment abroad should be encouraged to return rigs and service vessels to the United States by making it as attractive to operate here as abroad.

Intensify Efforts to Produce More Oil from Known Reservoirs

Economic incentives should be sufficient to encourage increased recovery of oil remaining in existing reservoirs. The well servicing industry has the capability to respond to increasing demands for services related to well stimulation and additional (secondary and tertiary) recovery projects.

FINDINGS AND CONCLUSIONS

HISTORICAL BACKGROUND

During the 1963-1973 period, activity levels in the domestic oil and gas producing industry have not been sufficient to maintain petroleum reserves in the proper relationship to production or demand. In fact, proved reserves have declined from 38.6 billion barrels of liquid hydrocarbons and 276.2 trillion cubic feet (TCF) of gas at the end of 1963 to 32.2 billion barrels and 224 TCF at the end of 1973.* (The 1973 data exclude 9.6 billion barrels and 26 TCF found on the North Slope of Alaska, since it is not yet on production.)

During this period, domestic production increased 26 percent for liquid hydrocarbons and 55 percent for natural gas. These increases resulted primarily from utilization of excess producing capacity. However, demand for oil and gas increased approximately 60 percent with increased imports filling the deficit between supply and demand.† In this period of rapid growth in demand and declining reserves, there were not adequate incentives or opportunities for operators to aggressively explore for new sources of energy in the United States.

Factors contributing to the decline in domestic activity and petroleum reserves include:

- Depressed oil and gas prices which resulted in decreasing exploratory activity.
- Reduced offerings of offshore areas for lease.
- Increased environmental restrictions.

The real (constant dollar) composite price of oil and gas declined 19 percent from 1963 through 1973.‡ Although the price of crude oil has increased considerably in the past year, gas committed to interstate markets continues to be regulated at an artificially low price when compared with other less desirable fuels on a heating value basis. Restricted offshore lease offerings and compliance with mounting environmental laws and regulations have significantly repressed the petroleum industry in expanding the domestic oil and gas reserve base.

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* American Gas Association (AGA), American Petroleum Institute (API) and Canadian Petroleum Association (CPA). *Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada and United States Production Capacity as of December 31, 1973*, Vol. 28, June 1974.

† Independent Petroleum Association of America (IPAA). *United States Petroleum Statistics* (Revised), 1974.

‡ IPAA, *ibid.*

Positive steps taken by government, as a result of the Middle East disturbances of the past year, are in the direction of increasing the domestic energy supply. Advancing petroleum prices, accelerated offshore leasing and approval of the Trans-Alaska pipeline have increased domestic activity substantially. However, reversing the historic downward trend requires a major commitment of capital by the petroleum industry and substantial time before results are evident.

The decline in activity during the 1963-1973 period is reflected in drilling as shown in Table 1. The decline in available rigs from 2,967 to 1,824 in the 10 year period reflects the forced liquidation of many drilling contractors due to lack of business and the consequent exporting or dismantling of their equipment for spare parts.

TABLE 1
HISTORICAL U.S. DRILLING ACTIVITY

	Rotary Drilling Rigs		Total Footage Drilled	Total U.S. Wells Drilled	Active Producing Wells
	Available*	Running†	(Millions of Feet)		At Year End ‖
1963	2,967	1,499	184.4‡	43,653‡	691,623
1973	1,824	1,194	138.9§	27,551§	623,002

*Reed Annual Rig Count—Includes some unworkable rigs stacked in contractor's yard.
†Hughes Weekly Rig Count, year average—December 1973 was 1,400.
‡*Oil and Gas Journal, Forecast/Review Issue,* Vol. 62, No. 4, Tulsa, Oklahoma, January 27, 1964.(Excludes core and stratographic tests.)
§American Petroleum Institute, *Quarterly Review of Drilling Statistics, Fourth Quarter 1973,* Vol. VII, No. 4, Washington, D.C.: API, March 1974. (Excludes core and stratographic tests.)
‖1973 well count published in *World Oil,* Vol. 178, No. 3, Feb. 15, 1974.

The only activity showing any increase during the decade was the number of gas wells drilled which increased from some 4,800 wells in 1963 to nearly 6,400 wells last year. This was largely due to the increased price of natural gas in the intrastate market, and drilling needed to meet deliverability provisions of gas sales contracts in some areas.

OUTLOOK FOR DRILLING AND PRODUCTION ACTIVITY

The facets of the oil and gas industry which were investigated include: exploration, drilling, tubular steel, production facilities, well servicing, gas processing plants, and drilling and production transportation. Except for tubular goods and drilling rigs, only isolated shortages in equipment and manpower were identified. All other phases of this sector of the industry should be able to respond to the projected 1974-1976 activity levels. The substantial increases in domestic oil prices during the last-half of 1973 gave producers increased incentives to search for new reserves and to maximize production from known reservoirs.

As shown in Table 2, the average number of drilling rigs operating in 1973 was 1,194. By year-end, some 1,400 were in operation, a level which is believed to represent near maximum utilization of the workable rigs available at that time. By the end of July 1974, operating rigs had reached 1,500 with an average for the first-half year near 1,400. Active rigs are expected to rise in 1976 to an average above 1,500, an increase of 27 percent over the 1973 average.

TABLE 2

PROJECTED U.S. DRILLING ACTIVITY

	Historical		Projected		Percent Increase
	1973	1974	1975	1976	1976 over 1973
Number of Wells Drilled	27,551	31,800	33,600	34,500	25
Number of Feet Drilled (Million Feet)	138.9	160	172	179	29
Average Depth (Feet)	5,042	5,030	5,130	5,190	3
Number of Rigs Operating	1,194	1,440	1,480	1,520	27

Figure 2 demonstrates that during 1974, tubular goods and other constraints will possibly cause a deferment of approximately 2,200 wells (11 million feet) that otherwise would have been drilled. Tubular goods supply is expected to balance drilling rig capability by the end of 1974; and therefore, drilling accomplished during the next 2 years should be constrained only by rig availability and efficiency. Lowered efficiency due to manpower and logistics problems may cause deferment of 600 wells (3 million feet) in 1975 but should have no effect in 1976.

CONSTRAINTS TO ACTIVITY EXPANSION

Tubular Steel

The shortages of oil country tubular goods (casing, tubing and drill pipe) stem from:

- A substantial rise in drilling activity caused by recent increases in the price of oil.
- A change in inventory and sales practices by the steel industry.
- The residual effects of price controls on the steel industry.
- The inability of the steel mills to increase production rapidly to meet these changing conditions.

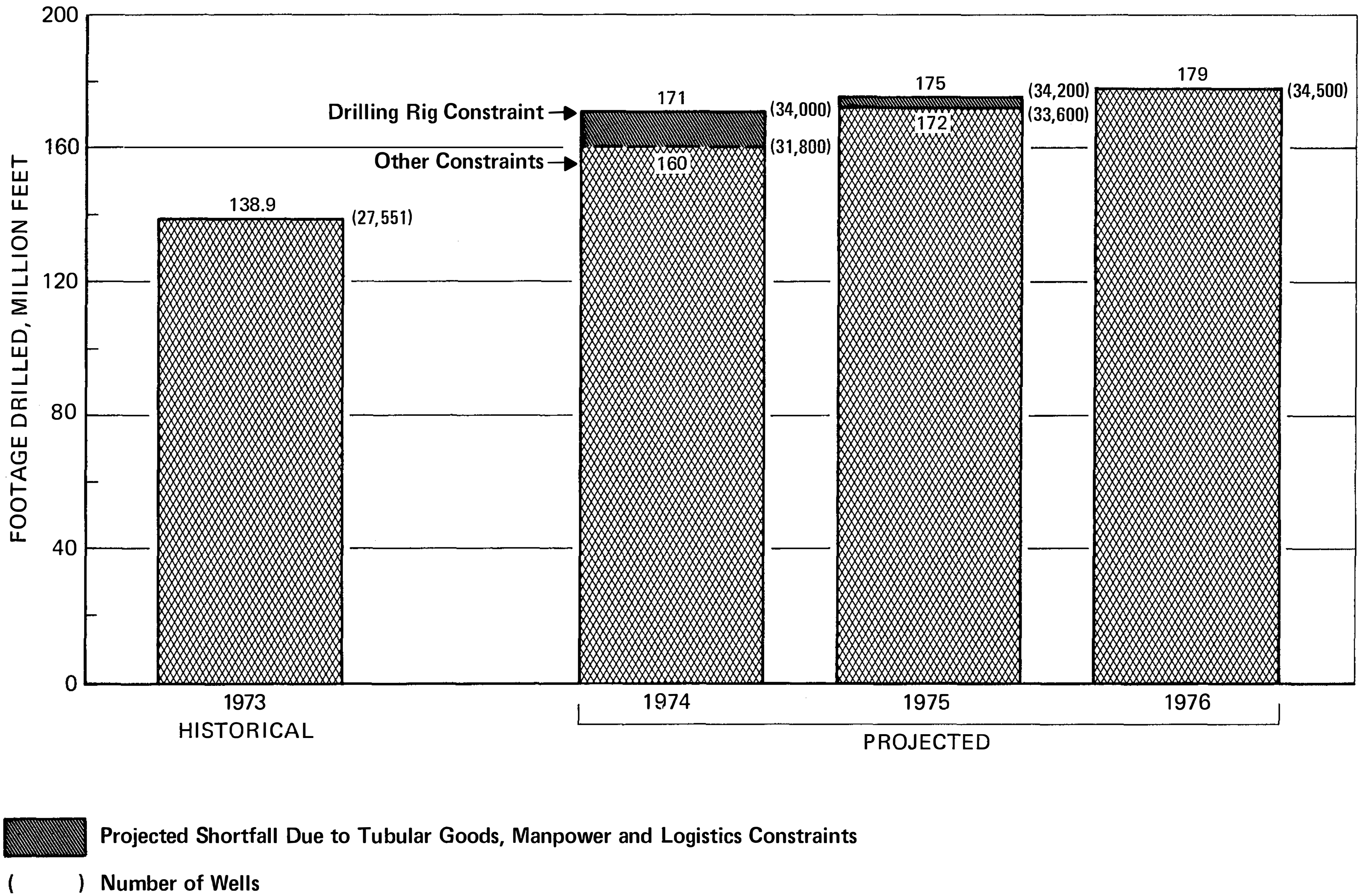

Figure 2. Projected U.S. Drilling Activity--1974-1976.

Changes in Steel Industry Supply Practices

For many years, the steel industry maintained inventories of oil country tubulars in several strategic locations near the heaviest drilling activities. The make-up and quantities were based on customers' estimates of requirements and the sales experience of the steel industry.

During the years of depressed drilling activity, these "in-transit" inventories were more than adequate. While the convenience and economies to the customer-operator were obvious, the return on investment to the steel industry was unattractive. In the third-quarter of 1973, each of the tubular goods manufacturers announced that mill shipments of oil country tubulars would be allocated based largely on each customer's purchase history, and that shipments to "in-transits" would be eliminated. As a consequence, each operator would have to maintain his own inventory.

An effective drilling program must be backed up by a "working inventory" of tubular goods, and therefore, a build-up of many individual inventories by oil companies has begun to replace the few strategic large ones. This change has substantially increased the total of inventories required overall (see Table 3). This, coupled with the large increase in demand, will cause oil country tubulars to remain in short supply until the inventory transition is completed. With the removal of price controls, increased manufacturing of tubulars has begun which speeded up the inventory transition process. Once the shift is completed, the flow of tubulars for consumption should be adequate to support drilling rig availability, although spot shortages of high-strength casing will probably continue through 1975.

Table 3 is a summary of the tubular goods situation and shows demand (determined by a detailed analysis of drilling activity), supply and inventory. During the 1970-1972 period, inventories remained virtually unchanged, indicating all tubulars shipped during that period were consumed. These shipments represented an average of 77 percent of the calculated demand, with the remaining 23 percent being made up of unidentified sources including salvaged pipe, line pipe used as oil country tubulars, unidentified imports and limited service or non-API pipe. With the assumption that the 23 percent figure will remain constant through 1976, usage from unidentified sources was calculated.

Industry estimates indicate that producer/operator inventories will rise to approximately 700,000 tons in 1974, 950,000 tons in 1975, and level off at approximately 1,050,000 tons in 1976. These inventory levels were used to estimate the portion of mill shipments going into user and supply store inventory and the portion consumed. The difference between the calculated demand at full rig utilization potential and the portion of mill shipments consumed, plus usage from miscellaneous sources, represents the estimated shortage.

The projected shortage of 167,000 tons in 1974 is the principal factor contributing to an expected drilling shortfall of some

TABLE 3

OIL COUNTRY TUBULAR STEEL SUPPLY AND DEMAND PROJECTION—CASING, TUBING AND DRILL PIPE FOR DOMESTIC DRILLING
(Thousand Tons)

	Historical				Projected		
	1970	1971	1972	1973	1974	1975	1976
Demand (Calculated consumption for History and Outlook Task Group Projection Based on Maximum Rig Utilization)	1,874	1,662	1,816	1,862	2,263	2,359	2,473
Supply							
Shipped from U.S. Mills Production	1,307	1,404	1,277	1,436	1,956	2,317	2,432
Plus shipments from U.S. Mill Inventory	—	—	—	300	150	—	—
Less exports	(88)	(81)	(95)	(198)	(300)	(300)	(300)
Plus imports	109	157	158	162	100	100	100
New Oil Country Tubular Goods (OCTG) available for domestic consumption	1,328	1,480	1,340	1,700	1,906	2,117	2,232
Consumption							
Consumption from miscellaneous sources*	546	182	476	429†	523†	492†	341†
Consumption of new OCTG	1,328	1,480	1,340	1,433	1,573	1,867	2,132
Total Consumption	**1,874**	**1,662**	**1,816**	**1,862**	**2,096**	**2,359**	**2,473**
Shortage (Demand less total supply consumed)	0	0	0	0	167	None‡	None‡
Domestic shipments to Pipe User Inventory	0	0	0	267	333	250	100
Inventory (Year-End)							
Pipe User Inventory	100	100	100	367	700	950	1,050
Steel Company Inventory	500	500	500	200	50	50	50
Total Inventory	**600**	**600**	**600**	**567**	**750**	**1,000**	**1,100**

*Use from inventory, rejects, line pipe used as oil country goods, secondhand pipe, unreported mill shipments and unidentified imports.

†Based on 1970-1972 average, 23 percent of demand assumed satisfied from miscellaneous sources. In 1975 and 1976 where "Total Consumption" equals calculated demand, consumption from miscellaneous sources may be reduced by some 53 and 230 thousand tons, respectively as more new tubulars become available.

‡ Annual figures indicate that by the end of 1975, supply will approach demand but there may be shortages during the year, particularly in high strength casing.

11 million feet (2,200 wells) from the projection of drilling that could be accomplished if drilling rigs were the only constraint. Table 3 indicates that in 1975, supply will approach demand; however, there may be spot shortages during the year, particularly in high-strength casing for deep drilling.

The following considerations are important to the interpretation and use of data in Table 3:

- While the total tonnage shipments projections for 1974-1976 are believed reasonable, shipments less than estimates could cause a reduction in wells and footage drilled.

- Availability of imports is quite uncertain because worldwide growth in demand has overtaken the world basic steel and pipe mill capacity. West German mills are committed to deliveries to the USSR, and substantial sales have been made by Japanese mills to the Peoples Republic of China.

- Oil and gas well abandonments in the United States are a relatively small but important source of tubing and casing. These used tubular goods now bring prices comparable with new pipe because of the tight supply situation. Oil well abandonments dropped from around 20,000 in 1972 to under 15,000 in 1973 and are projected to decrease even further. Gas well abandonments which totaled about 4,000 a year in 1972 and 1973 are also expected to drop somewhat in 1974. The relative economics of abandonments for salvage *versus* continued production will dictate the magnitude of this supply.

- The total tonnage of oil country tubular goods shipped for domestic use cannot serve as a complete indication of supply/demand balance. The tight supply situation prevailing in 1974 and projected for 1975 includes grade and size availability as well as basic tonnage. All deep-wells must use some high-strength casing and, if successful, high-strength tubing.

- The American Iron and Steel Institute indicates about 44 percent of the casing, tubing and drill pipe shipped from U.S. mills in 1973 was high-strength material.* The need for high-strength pipe is increasing and is projected to continue to rise beyond 1976. Since there is restricted capability for production of this material, there may be a continuing restraint on deep-well drilling activity.

- Drill pipe is in short supply but is not a measurable constraint to drilling activity. In 1973, drill pipe represented less than 8 percent of total U.S. output of high-strength oil country tubular goods. Drill pipe manufacture is limited by the capacity of the same equipment that is used to make high-strength casing. The problem of competing for mill space is made more acute because a length of drill pipe requires twice as much mill capacity to produce as a comparable length of high-strength casing. Thus, increases in drill pipe production at present will reduce the output of twice that length of high-strength casing.

- The present attractive economics should encourage expansion of heat treating capacity as well as basic carbon steel tubular production, and only a small increase of both should bring tubular supply into balance with rig availability.

Drilling Rigs

Figure 2 indicates that if all workable drilling rigs in the United States are utilized at maximum feasible capacity, and if

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* American Iron and Steel Institute, (published statistics for 1973).

there were no other constraints, 171 million feet could be drilled in 1974, 175 million feet in 1975 and 179 million feet in 1976. These rates represent an increase of 22 percent per year in 1974, but much smaller increases in 1975 and 1976. The footage estimates are calculated by geological regions and well-depth categories and are based upon the rig availability and utilization data summarized in Table 4.

TABLE 4

U.S. RIG AVAILABILITY AND UTILIZATION

Workable Rigs at Year End	Historical 1973	Projected 1974	1975	1976
Land Rigs	1,502	1,520	1,541	1,559
Offshore Rigs				
Stationary	75	81	88	96
Mobile-Bottom Supported	58	62	67	77
Floaters	15	21	32	41
Total Offshore	**148**	**164**	**187**	**214**
Total All Rigs	**1,650**	**1,684**	**1,728**	**1,773**
Net Additions		34	44	45
Workable Rigs—Annual Average	1,635	1,667	1,706	1,751
Utilization Factor—Percent	73	86	87	87
Active Rigs—Annual Average	1,194	1,440	1,480	1,520

After all existing workable rigs are being utilized at a near maximum feasible rate, additional drilling capacity will be limited by drilling rig equipment manufacturing capacity (with offshore expansion further limited by capacity of construction yards to produce offshore drilling platforms).

Projections of new rig availability are based on the assumption that steel will be made available to manufacture rig components such as derricks and masts, mud pumps and the many other necessary parts of the total drilling system to match the production of new draw works and other hoisting system components.

The export demand for drilling rig equipment and complete mobile offshore rigs is expected to continue at a high-level for many years. While total drilling rigs manufactured in the United States are projected to increase from 135 in 1974 to 162 in 1975 and 178 in 1976, 50-60 percent are believed to be under contract for export. Table 5 shows an estimate of net rig additions for the 1974-1976 period.

A significant increase in drilling rig availability will occur only several years after manufacturers undertake expansion of plant

TABLE 5

U.S. RIG AVAILABILITY, NEW RIG ALLOCATION AND WORKABLE RIGS

	1974		1975		1976	
Type and Number of New Rigs Manufactured in U.S.						
Offshore Mobile	49		50		50	
Remaining in U.S.		11		17		20
Exported		38		33		30
Fixed	86		112		128	
Remaining in U.S.		48		52		50
Exported		38		60		78
Total New Rigs Manufactured	135		162		178	
Distribution of New Rigs Remaining in U.S.						
Offshore Mobile	11		17		20	
Platform	7		8		9	
Land	41		44		41	
Total Remaining in U.S.	59		69		70	
Less: Attrition	25		25		25	
Offshore		2		2		2
Platform and Land		23		23		23
Net Rig Additions in U.S.	34		44		45	

capacity. But they cannot make decisions for the required capital investments to expand capacity unless assured of a continuing high-level of demand for many years.

Other Materials for Drilling

Materials for maintenance, repairs and operating supplies for drilling are generally difficult to obtain but none is expected to be a major deterrent to expanded activity. Many items that could be purchased off the shelf in early 1973 now have a lead time of many weeks. Tool joints for drill pipe, which were a constraint in 1973, have come into balance with drill pipe availability and are not expected to be a restraining influence. Drill bits are expected to keep pace with the growing demand. Drill collars, the thick walled sections of pipe which are placed between the drill pipe string and the bit to provide weight and rigidity in the drill string, are not expected to be a specific constraint to drilling activity.

The drilling process requires that a fluid be pumped down the drill pipe and circulated back to the surface to lubricate and cool the bit, carry drill cuttings out of the hole and supply hydrostatic head to control formation pressure. Drilling fluid varies from natural mud generated by simply drilling with fresh water to sophisticated chemical colloidal mixtures. The most commonly used material to add weight to the fluid is barite (barium sulphate). Since 47 percent of domestic requirements are imported, barite could become a constraint, but this is not expected to occur by

1976. There is a short supply of many drilling fluid chemicals, particularly caustic soda; however, the drilling industry's use of these materials is small compared with the total supply, and slight modifications in the distribution of these chemicals can alleviate potential problems.

In summary, spot shortages and longer lead times for other equipment and materials may impede the attainment of expanded drilling programs, but none is expected to be an important constraint.

Surface and Subsurface Production Equipment

Structural steel used in offshore production platforms is the largest single item of material requirements for production equipment. Present fabrication yard capacity is approximately 200,000 tons per year. This can be expanded to meet the requirements inherent in the platform projections shown in Table 6, subject to the availability of steel plate, pipe and structural shapes.

With lead times on beam pumping units being extended to a year or more, manufacturers of beam and rod pump equipment will continue to operate at capacity through 1976. While the 1974 supply/demand projection indicates a shortfall of 10 percent, this is sensitive to change in the historic rate of well abandonments (the majority of which are estimated to be beam and rod pumped), re-employment of surplus pumping units and use of alternate artificial lift equipment (gas lift, hydraulic, subsurface electric centrifugal pumps).

Planned expansions of manufacturers should alleviate the problem but shortages will continue for some time. Capacity for furnishing gas lift, hydraulic and electric subsurface pumps and sucker rods for beam pumps is adequate for the next 3 years.

Many other items of equipment necessary for production of oil and gas now have long lead times for delivery; however, at this time none is expected to restrict production. These include electrical equipment, prime movers, surface oil and gas handling equipment, production chemicals, subsurface equipment, waterflood-gas injection equipment, wellhead equipment, christmas tree (well control) valves and line pipe for oil and gas gathering systems.

TABLE 6

OFFSHORE FIXED PLATFORM CONSTRUCTION

		Projected	
	1974	1975	1976
Number Fabricated and Installed	50	55	60
Average Water Depth (Feet)	175	185	195
Platform Tonnage (Thousand Tons)	150	176	204
Production and Drilling Rig Packages Added Requirements (Thousand Tons)	30	33	36
Total Steel Requirements (Thousand Tons)	**180**	**209**	**240**

Well Servicing Equipment and Service

The U.S. well servicing industry consists of more than 50 separate functions and supports drilling and producing activities from the time drilling starts until final well abandonment. Well servicing companies perform engineering, manufacturing and installation services. In 1973, they employed approximately 140,000 people in the United States with sales of around $4 billion. Services furnished include cementing, fracturing, acidizing, well sand control, directional drilling, electric and other types of well logging, perforating, artificial lift servicing and well workovers. Associated equipment includes production workover rigs, high pressure pumps, mixing devices, instruments and controls, electric wire line units and many types of specialized surface and subsurface tools and equipment.

It should be noted (see Appendix C, Figures 10, 11, and 16) that the same equipment and services are used for both drilling and producing wells. Therefore, the rapid increase in demand in late 1973 for services related to new well drilling was in addition to existing strong demand for production maintenance services. The services provided by this industry increased 15 percent in 1973 and are expected to increase 25 percent in 1974, primarily through improved utilization of existing equipment and manpower. Another 25 percent expansion can be accommodated in 1975 with a 10 percent addition to the service unit fleet (cementing trucks, electric wireline units, etc.), more efficient scheduling, and longer hours of operation of service units and workover rigs. Further expansion in 1976 will require major investment decisions before the end of 1974.

The availability of workover rigs is expected to be the most critical well servicing item during the next 3 years. The number of operating rigs is projected to increase about 5-6 percent per year through 1976. The average number of rigs available was about 3,200 in 1973 and is projected to exceed 3,700 in 1976. Since the demand for the workover rigs is anticipated to increase about 25 percent per year after 1973, projected rig availability will be insufficient by 1975 if rigs continue to operate only during daylight (10 usable hours). Around-the-clock utilization (a usable 16 hours) in critical geographical areas could handle a 35 percent annual increase in demand through 1976. If the estimated 1974 utilization rate of 91 percent and 10 hours operation continues, rig service availability can increase only as rig numbers increase, or about 6 percent for each of the next 2 years.

The above estimates of workover rig availability, and the estimates of workable drilling rigs (see Table 4), do not take into account the increasing use of the new larger rigs to drill shallow wells. Most new workover rigs are capable of new well drilling with the addition of mud pumps, tanks, blowout preventers and a power swivel. Relative economics and local opportunities for contractors and producers will determine whether such a rig will be used for drilling or continue to perform service work.

Gas Processing Plants

Gas processing plants extract liquid hydrocarbons from wet gas produced from oil and gas wells. Operations include compression, refrigeration, fractionation and removal of impurities. The extracted products are natural gasoline (pentane plus), butanes, propane, ethane or a combination of these hydrocarbons. Products are usually transferred in marketable form through liquid and gas transmission lines.

Carbon steel requirements for gas processing plants are expected to be about 250 thousand tons yearly in the 1974-1976 period. About 90 percent of this is for gathering systems with the balance for new plants, expansion of existing plants, compressors and plant maintenance. While the needs are small compared with other sectors of the petroleum industry, steel for gas processing could become a constraint if adequate steel supplies are not available.

Fabricated equipment is not believed to be a major restraint, although lead time for some essential items now exceeds 40 weeks (heat exchangers, process vessels and engines). Competing demand for these and other commonly used items (e.g., heaters, pumps, motors and controls) from refineries, petrochemical plants, fertilizer plants and other industries could cause delay of some gas plant projects.

Geophysical Services

Equipment utilized for geophysical work includes magnetometers, gravimeters, seismic energy generators, receivers and recorders, and data processing programs and equipment. Seismic services are not expected to constrain drilling over the next few years, since much of the seismic work has already been done on the prospects that will be drilled during this period. There do not appear to be any restraints to expansion of offshore seismic service. There is, however, a current shortage of onshore field crews and trained manpower for interpretation of the accumulated geophysical data.

Transportation and Fuel

No major constraints on drilling and producing activity are anticipated from basic transportation equipment (vehicles, boats and aircraft) or fuel. While the industry is not being impaired in 1974, the increasing lead time for replacement of equipment and availability of spare parts for trucks may be a problem in the next 2 years and could result in delayed movement of rigs between locations.

Basic Steel

While the petroleum industry uses only 6 percent of the domestic output of basic steel, most manufacturers of oilfield equipment are highly dependent on adequate steel supplies. Without exception, all oil equipment manufacturers express concern over their ability to continue to obtain currently required supplies and, more particularly, the additional steel supplies required for indicated increases in output. In many cases, plans of manufacturers are predicated on maximum domestic allocations supplemented by significant imported steel supplies. Steel supplies could be a serious constraint for such primary uses as plate for platform construction and surface handling facilities, as well as secondary steel requirements of manufacturers and sub-suppliers. Any shortfall of total steel supply will cause a net reduction in the indicated capacities of the various manufactured equipment segments. The situation could become critical in the event of a coal strike resulting in a disruption of steel production.

Other Basic Materials and Equipment

Tight supplies of basic resources (plant capacity, materials and manpower) have created extended lead times for most other required items.

- *Castings and Forgings:* All manufacturers identify these as shortage items, often critically, and with no immediate foreseeable relief. Rigorous enforcement of Occupational Safety and Health Administration (OSHA) and Environmental Protection Agency (EPA) regulations have caused the shutdown of many small marginally economical foundries. Such foundries in the aggregate have historically been a significant source of supply.

- *Electrical Equipment:* Manufacturers identify the shortage of copper wire and related insulating materials as a constraint to equipment delivery. Bronze for bearings is also in short supply.

- *Machine Tools:* Long lead times are a potential constraint expansion of manufacturing capacity.

Despite tight supplies for these items, none is expected to be a critical constraint to needed expansion of exploration, drilling and production.

Manpower

Trained manpower availability is a definite problem in expansion of all exploration, drilling and production activities and their supporting industries. The most critical shortage identified at this time is in personnel for interpretation of geophysical data, but this should not delay short-term exploratory drilling programs.

Oil and gas producers and drilling and well servicing contractors have continuous programs for recruiting and training new employees and for upgrading their existing work forces, but labor turnover is high for drilling and workover rig contractors. The work is difficult, must be performed in all kinds of weather and is nomadic. This high turnover rate does not reduce the number of active rigs but reduces operating efficiency. Previously inactive rigs mobilized during 1974 have lowered the overall efficiency of the drilling industry, due partly to manpower problems. Intensive training is expected to relieve the drilling manpower constraint by 1976.

Nearly all manufacturers of oilfield equipment indicated a concern for the availability of adequate skilled manpower such as welders, machinists and pipefitters. Most manufacturers have increased internal training programs to develop their own skilled labor forces, but the supply of qualified candidates is limited. Several manufacturers also identified shortages of engineering personnel, draftsmen and common laborers for the 1974-1976 period.

Several manufacturers, particularly those in the fabrication business, indicated that Occupational Safety and Health Administration regulations have adversely affected productivity by as much as 15 percent.

In summary, while specific limitations cannot be quantified, shortages of skilled manpower will be a problem in rapid expansion of manufacturing capacity and new construction. Drilling and well servicing contractors are manning reactivated and new rigs as they become available, but with lower operating efficiency.

Capital Availability

It appears that adequate capital will be available to the petroleum industry to expand exploration and drilling in line with availability of equipment and manpower during the 1974-1976 period. Longer-range, free market prices of domestically produced hydrocarbons will be needed to generate sufficient internal capital (in the form of profits) to attract enough outside funds to increase exploration and drilling within the United States, at a rate consistent with the expansion outlined in this report.

Similarly, capital formation of all segments of the petroleum service industry appears adequate to provide equipment and supplies for increased operations through 1976. But for the longer-term, a clear energy policy leading toward increased development of indigenous energy supplies must be set forth to assure the service industry of steadily rising profits so that adequate plant expansion can begin soon and be financed, if necessary.

LONG-RANGE OUTLOOK FOR DRILLING ACTIVITY

Over the long term, drilling rig availability will most likely be the primary restraining influence on increased drilling activity.

The National Petroleum Council's 1972 report, *U.S. Energy Outlook*, examined several levels of possible drilling activity through 1985. Case I of the report assumed a drilling rate reaching 250 million feet per year in 1980 (35 million offshore) and nearly 300 million feet in 1985 (50 million offshore). The report indicated that the domestic oil and gas resource base, discoverable and producible, is adequate to support such a large expansion of the industry.

For purposes of the current study, it was assumed that economic incentives will be sufficient to motivate this rapid growth of petroleum activity, that governmental policies will encourage expansion, and that financing of the large investments required will be available. Current trends indicate that tubular goods and other equipment and services can be made available to supply expanded needs. With these assumptions, drilling rig requirements were calculated to achieve NPC Case I activity levels for the 1977-1985 period.

Due to the relatively low projected output of domestic rigs through 1976, domestic rig additions for 1977--the first year in which significant increases in rig deliveries can be made--would have to be more than 250 rigs to reach Case I activity levels in that year and this figure is considered to be unattainable. A more plausible approach is to assume that drilling rig manufacturers in the United States can expand deliveries at an increasing rate after 1976 by beginning a substantial expansion of manufacturing capacity in 1974.

If one-half of the new rigs to be built from 1976 to 1980 are exported, an expansion of more than 30 percent per year from 1976 would be needed to reach a rig level of 2,400 rigs in 1980 which would be required to drill at the rate of the 250 million feet for Case I. A more reasonable growth rate of 10-15 percent annually after 1976 (a rate of 11 percent calculated) would allow realization of Case I activity of 300 million feet by 1985 with about 2,900 workable rigs. Although the NPC drilling activity levels are ambitious, they are achievable in the 1980-1985 period if the industry is given adequate economic incentives and stable governmental policies.

Comparable growth rates must be attained in all other segments of the oil producing industry, particularly offshore production platforms, workover and rod pulling units, pumps, trucks and allied equipment for bulk material handling and formation stimulation jobs.

Chapter One

OUTLOOK

OVERVIEW AND SUMMARY

For the 1974-1976 period, the high demand for crude oil and natural gas coupled with the current increased prices for petroleum products indicate an "all out" effort by the drilling and service segments of the industry. Overall domestic petroleum industry activity levels through 1976 are reflected and dependent, to a large extent, by the rate of drilling in the United States. Long-term, for the United States to move toward a significant degree of energy self-sufficiency, there is a vital need for substantial expansion of manufacturing and support facilities. This expansion will be realized only if the economic climate exists to assure equipment manufacturers and suppliers of an era of high demand.

Over the past decade, drilling activity in the domestic petroleum industry has declined substantially. This is the result of several factors, including depressed wellhead prices for oil and gas, increased activity in foreign areas, environmental restrictions and, until the early 1970's, spare domestic producing capacity. These and other factors have resulted in a reduction in the number of domestic drilling rigs and have caused a large percentage of the new domestic manufactured rigs to be exported to foreign areas.

A maximum effort by the domestic drilling industry is projected for the 1974-1976 period. The approach used to quantify the results of this effort in terms of wells and footage drilled involved analysis of possible limiting factors including (a) drilling rigs, (b) tubular steel, (c) production equipment, (d) well servicing, (e) gas processing plants, (f) transportation services and (g) manpower. The number of wells and footage drilled (assuming drilling rig availability as the only constraint) was estimated first, since drilling rig availability was an apparent constraint and evaluation of other possible limiting factors requires considerable detail regarding the number, location, type and depth of the wells to be drilled.

Results of this analysis considering all possible drilling activity constraints are shown in Figure 2 (page 12) and represent the most probable situation. The shortage of tubular goods as well as trained crews and logistics problems will most likely result in the deferring of some 11 million feet (about 2,200 wells) in 1974, with a smaller (3 million feet and 600 wells) effect in 1975 and no effect in 1976. The near balance of tubular goods and drilling rig availability should have little effect on the number of active drilling rigs but causes a reduction in drilling rig efficiency. Results of drilling activity for the first-half of 1974 support this analysis.

Although the primary purpose of this report is to focus on the near-term outlook (1974-1976), the long-range need for expanded manufacturing capability was examined, since major investment decisions are necessary 2-3 years in advance of actual capacity increases. Long-range projections can only be directional and are sensitive to a variety of assumptions. Projections were made for the probable number of drilling rigs and offshore production platforms (although other equipment items should generally conform to the projections for rigs and platforms). Results of this long-range analysis indicate that equipment manufacturing capability will need to expand rather dramatically if the United States is to move toward a significant degree of self-sufficiency. In fact, to reach the activity levels outlined in Case I of the NPC *U.S. Energy Outlook* while continuing to export some 50 percent of the new rigs constructed in the United States, an expansion of about 11 percent per year is required until 1985.* While Case I activity levels and assumed finding rates are high, it should be noted that they are not projected to result in U.S. energy self-sufficiency even by 1985. This rate of rig expansion would result in footage drilled in 1985 of about 300 million feet. Although annual growth in drilling is postulated to be small beyond 1985, demand for the new equipment should continue to utilize the expanded manufacturing facilities.

The remainder of this chapter details the assumptions and methodology used in arriving at the outlook findings summarized above. The material is divided into three sections:

- Historical Drilling Activity in the U.S. Petroleum Industry
- Projected U.S. Drilling Activity Assuming Rig Availability Will Be the Only Constraint: 1974-1976
- Longer-Range Aspects of Materials and Manpower Requirements.

Historical Drilling Activity in the U.S. Petroleum Industry

Although higher levels of drilling appear certain in the future, domestic activity has declined significantly over the past decade. Table 7 shows that the number of producing oil wells in the United States declined from some 589,000 in 1963 to 500,000 in 1973. Although the number of producing natural gas wells increased 20,000 wells over this period, the net effect is a decline in total producing wells from 692,000 in 1963 to 623,000 in 1973, a drop of about 10 percent. The number of stripper wells, (those wells producing less than 10 barrels of oil per day) also declined as shown in Table 8. While there were 401,000 stripper wells in 1963, by the end of 1972, stripper wells had declined to 359,000. Stripper wells provided nearly 20 percent of domestic crude production in 1963, but only 12 percent in 1972. It is expected that abandonments of stripper wells will decrease significantly over

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* In *U.S. Energy Outlook*, Study Case I is high drilling, high finding rate case.

TABLE 7

ACTIVE PRODUCING WELLS IN THE UNITED STATES
(At Year-End)

	Oil Wells*	Natural Gas Wells†	Total
1963	588,657	102,966	691,623
1964	588,225	103,084	691,309
1965	589,203	111,680	700,883
1966	583,302	112,498	695,800
1967	565,289	112,321	677,610
1968	553,920	114,391	668,311
1969	542,227	114,476	656,703
1970	530,990	117,483	648,473
1971	517,318	120,210	637,528
1972	508,443	121,153	629,596
Preliminary			
1973‡	499,968	123,034	623,002

Oil and Gas Journal, Forecast/Review Issue, Vol. 72, No. 4, Tulsa, Oklahoma, January 28, 1974. Cites API-AAPG data.
†U.S. Department of Interior, *Bureau of Mines Yearbook 1972* Vol. 1, Washington, D.C., 1973.
‡*World Oil,* Vol. 178, No. 3, "U.S. Oil Wells Down Slightly," Houston, Texas, February 15, 1974.

TABLE 8

NUMBER OF STRIPPER WELLS IN THE UNITED STATES*

	Number of Wells (At Year-End)	Number of Abandonments (During Year)	Percent of U.S. Crude Oil Production (During Year)
1963	401,031	14,363	19.5
1964	394,107	14,476	19.2
1965	398,299	15,456	20.7
1966	380,549	16,267	16.0
1967	376,851	14,986	15.5
1968	367,205	20,496	14.6
1969	358,650	15,618	13.5
1970	359,130	15,631	12.5
1971	353,696	18,421	12.3
1972	359,457	13,483	11.9

Note: 1973 data not available.
*Stripper Wells are defined as wells producing less than 10 barrels per day.
Source: Interstate Oil Compact Commission, National Stripper Well Association, *National Stripper Well Survey,* Oklahoma City, Oklahoma: IOCC, published annually.

the short-term due to the substantially improved economics of operating stripper wells.

Tables 9 and 10 show the number of wells drilled and footage drilled, respectively, since 1963. Total wells drilled have declined from about 44,000 in 1963 to less than 28,000 in 1973, while footage drilled declined from 184.4 million feet in 1963 to 138.9 million feet in 1973. The only category showing an increase over this period was gas-well drilling where activity grew from 4,751 wells in 1963 to 6,385 wells in 1973. This increased drilling is due to increased demand for gas in the intrastate markets where gas prices are not regulated by the Federal Power Commission (FPC). Also, obligatory drilling to meet gas sales contract provisions has been required in some areas.

The number of deep-wells drilled in the United States has also increased since 1963. As shown in Table 11, there were 271

TABLE 9

NUMBER OF NEW WELLS DRILLED IN THE UNITED STATES
(Ex Strat and Core Tests)

	Oil Wells	Gas Wells	Dry Holes	Service Wells	Total Wells	Exploratory Wells	Development Wells
1963	20,288	4,751	16,347	2,267	43,653	10,664	30,722
1964	20,620	4,855	17,488	2,273	45,236	10,747	32,216
1965	18,761	4,724	16,025	1,922	41,432	9,466	30,044
1966	16,780	4,377	15,227	1,497	37,881	10,313	26,071
1967	15,329	3,659	13,246	1,396	33,630	8,878	23,356
1968	14,331	3,456	12,812	1,439	32,038	8,879	21,720
1969	14,368	4,083	13,736	1,490	33,677	9,701	22,486
1970	13,020	3,840	11,260	1,221	29,341	7,693	20,427
1971	11,858	3,830	10,163	1,399	27,250	6,922	18,929
1972	11,306	4,928	11,057	1,434	28,725	7,539	19,752
1973	9,902	6,385	10,305	959	27,551	7,466	19,126

Sources: American Petroleum Institute, *Petroleum Facts and Figures,* Washington, D.C.: API, 1971.
American Petroleum Institute, *Quarterly Review of Drilling Statistics, Annual Summary,* published annually, Washington, D.C.: API.

TABLE 10

TOTAL FOOTAGE DRILLED IN THE UNITED STATES

	Total Footage (Million Feet)
1963	184.4
1964	189.9
1965	181.5
1966	166.0
1967	144.2
1968	148.3
1969	160.4
1970	142.3
1971	128.2
1972	138.3
1973	138.9

Source: *Oil and Gas Journal, Forecast Review Issue,* published annually. Includes both new wells and old wells drilled deeper. Core and strat tests not included.

TABLE 11

NUMBER OF DEEP WELLS DRILLED IN THE UNITED STATES
(15,000 Feet and Below)

	Wells Drilled (Number)	Average Depth Per Well (Feet)
1963	271	16,241
1964	308	16,610
1965	330	16,735
1966	388	17,252
1967	402	16,839
1968	406	17,072
1969	389	17,016
1970	381	17,270
1971	417	17,332
1972	506	16,963
1973	506	17,413

Source: John Scott, Editor, *Petroleum Engineer,* Vol. 46, No. 3, U.S. Deep Drilling Continues at Record Pace, March 1974.

wells drilled deeper than 15,000 feet in 1963, while in 1973, 506 deep-wells were drilled. Average depth of these deep-wells has also increased from some 16,200 feet in 1963 to 17,400 feet since last year.

Table 12 is a summary of drilling activity over the 1963-1973 period. As shown, both the number of operating rigs and footage drilled declined over the 1963-1973 period. Average well-depth increased from 4,200 to over 5,000 feet during this period, with footage drilled per rotary rig remaining approximately constant.

TABLE 12

U.S. DRILLING SUMMARY—1963-1973

	Rotary Rigs Running*	Footage Drilled† (Million Feet)	Average Well Depth† (Feet)	Total Footage per Rotary Rig (Thousand Feet Per Rig)
1963	1,499	184.4	4,223	123.0
1964	1,501	189.9	4,198	126.5
1965	1,387	181.5	4,381	130.8
1966	1,272	166.7	4,399	131.0
1967	1,135	144.7	4,195	127.5
1968	1,171	149.3	4,461	127.5
1969	1,195	160.9	4,726	134.7
1970	1,028	142.4	4,834	138.6
1971	976	128.3	4,701	131.5
1972	1,107	138.3	4,809	124.9
1973	1,194	138.9	5,042	116.3

*Hughes Tool Company.
†American Petroleum Institute, *Quarterly Review of Drilling Statistics, Annual Summary,* published annually, Washington, D. C.: API.

Projected Drilling Activity Assuming Rig Availability Will Be the Only Constraint: 1974-1976

Domestic drilling based on rig availability for the 1974-1976 period was projected to determine overall industry materials and manpower requirements and to facilitate evaluation of other possible drilling constraints such as tubular goods, production facilities, etc. The projection developed is a composite of wells and footage drilled by geographic areas and by depth interval.

The approach used in making the drilling projection was to first subdivide the United States into geographic regions with similar drilling characteristics. Second, an analysis of rig availability was made for past years and projected through 1976. This analysis considered current rig levels and net changes through rig manufacturing, exports and retirements. Next, historical well and footage data covering 1970 through 1973 was sorted into four well-depth intervals for each of the established regions and related to the historical rig count within that region. This yielded two necessary parameters, wells per rig-year and footage per rig-year, which were used in conjunction with the rig availability to project future drilling activity.

Geographic and Well-Depth Breakdown

For analysis, various regions were defined and are shown in Figure 3. States or parts of states in each region as listed in Table 13. This breakdown groups geographic areas by type of drilling and is consistent with most published data sources. Although there has been some combining and several slight modifications of boundary lines, the breakdown is consistent with the NPC's *U.S. Energy Outlook* study. A breakdown by well-depth is also needed to evaluate tubular requirements as casing programs vary depending on well-depth. Four (4) depth intervals were chosen: (1) 0-5,000 feet, (2) 5,000-10,000 feet, (3) 10,000-15,000 feet, and (4) 15,000 feet and over.

Historic Wells, Footage and Drilling Rig Data Analysis

Well and footage data were gathered and analyzed in detail for the 1970-1973 period. The data were assembled by geographic region and broken down further by depth interval, type of well (oil, gas, dry or service) and type of activity (exploratory or development and service). Well and footage data include only new wells, as footage reported on old wells drilled deeper is the only "deepened" footage (see Appendix D, Figures 17 through 40).

Two primary sources of information on rig availability and utilization were used for the analysis: The Reed Tool Company Annual Rotary Rig Census and the Hughes Tool Company Weekly Rotary Rig Count. For offshore rig totals, these sources were supplemented by *Offshore Magazine* and the *Offshore Rig Locator Service*.

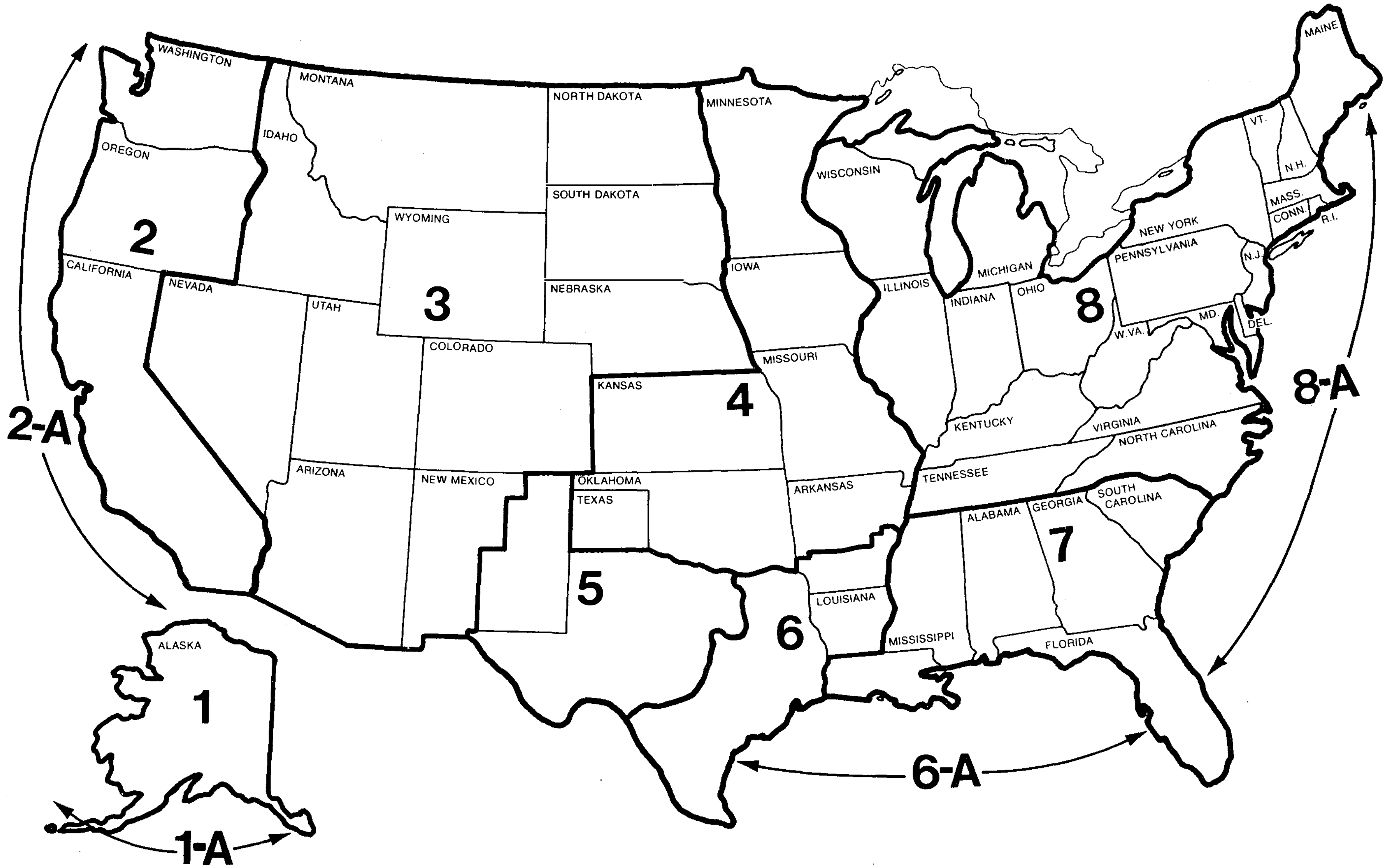


Figure 3. Region Boundaries, NPC Materials and Manpower Requirements--1974.

TABLE 13

LISTING OF STATES OR PARTS OF STATES BY REGIONS

NPC Region	Description	State(s)
1	Alaska Onshore	
1A	Alaska Offshore	
2	Pacific Coast	California, Oregon, Washington
2A	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
6A	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
8A	Atlantic Offshore	

Although it is recognized that rotary rigs do not make up 100 percent of the domestic oil well drilling equipment, the other type--namely, cable tool rigs--are confined to shallow-well drilling and do not drill a significant percentage of either footage or wells. Due to this fact and lack of accurate data on cable tool rigs, all drilling activity has been related to rotary drilling equipment.

The Reed Rig Count is taken on a regional basis each year. These regions are consistent with this study's inland region breakdown. Reed also reports offshore rigs separately, which allows breakout by the offshore regions used in this study. Of particular interest is the total existing rigs and their breakdown into region and drilling depth interval. In summary, this census provides a count as to the number of rigs by geographic area broken down by drilling depth capability.

A second source of rig availability data is the Hughes Tool Company Weekly Rotary Rig Counts. The Hughes Rig Count, by definition, includes only *active* rigs "in the process of, or in a position to consume rock bits." This excludes rigs moving, fishing, testing, running pipe, or otherwise engaged in non-drilling operations. The Hughes Rig Count is reported for each state or industry recognized state split (Texas RRC, Offshore, etc.) and can therefore be used to relate *active* rigs to the wells and footage drilled in each of the previously established regions. By relating the Hughes *active* count to the depth interval breakdown given in the Reed Rig Count, it is possible to obtain a Hughes Rig Count for each depth interval as shown in the following formula:

$$\text{Hughes Rig Count for Region Total} \times \frac{\text{Reed Rig Count for Depth Interval}}{\text{Reed Rig Count for Total Region}} = \text{Hughes Rig Count for Region Depth Interval}$$

Several modifications and checks were made on the Reed data to justify use of the above formula. A detailed analysis of 1973 data was completed to verify the assumption that the depth interval distribution of *active* rigs is proportional to that of *total* rigs. The analysis showed the assumption to be valid. Completion of these calculations, then, resulted in the Hughes Rig Count broken down by depth interval for each of the 11 regions.

Rig efficiency indices were then calculated by dividing the wells and footage data discussed at the beginning of this section by the Hughes Rig Count for each depth interval in each region. This gave a well per rig-year and footage per rig-year index to be plotted for 1970 through 1973 and extrapolated through 1976. These extrapolated indices were then used in conjunction with the rig availability analysis outlined below to give a detailed wells and footage projection through 1976.

Projected Rig Availability: 1974-1976

Projecting drilling rig availability over the next 3 years requires consideration of several factors, including current rig levels, new manufacturing, exports and retirements. Also, utilization factors must be considered; that is, the number of rigs actually making hole relative to the number capable of drilling. Obviously, this utilization can never be 100 percent due to rig moves, repairs, fishing jobs, well completion, well testing, waiting on cement, etc.

Current rig levels, shown in Table 14 were determined through analysis of Reed Tool Company and Hughes Tool Company information supplemented by other sources for offshore areas. Rig levels were categorized in three manners:

(1) *Existing Rigs*--a count of all rigs including those used for spare parts in order to keep other rigs operating. This count totaled 1,850 rigs as of the end of 1973.

(2) *Workable Rigs*--calculated by reducing the existing rig count to account for those rigs believed to have been cannibalized. For 1973 some 11 percent of the "existing rig" total of 1,850 were believed cannibalized leaving a total of 1,650 workable rigs for the year.

(3) *Active Rigs*--a count of those rigs actually making hole at any given time. This is, by definition, the Hughes

Rig Count. The 1973 *active* rig count averaged 1,194: a 73 percent utilization of the 1,650 workable rigs.

TABLE 14

CALCULATION OF CURRENT RIG LEVELS IN THE UNITED STATES
(End-of-Year 1973)

	Number Rigs	
CATEGORY 1—EXISTING RIGS		
Reed Count, August 1973		
>3M-Depth Capability	1,767	
<3M-Depth Capability	57	
New Construction, August-December	26	
Total Existing Rigs		1,850
CATEGORY 2—WORKABLE RIGS		
Adjustment for Rigs "Stacked in Yard" as shown in Reed Count	–83	
Adjustment for Rigs "Stacked on Location" — Total of 211 shown in Reed Count	–117	
Total Adjustment*	–200	
Total Workable Rigs (End-of-Year)		1,650
CATEGORY 3—ACTIVE RIGS		
Hughes Count (Annual Average) for 1973 is 1,194 Active Rigs.		
Total Active Rigs		1,194

$$\text{Utilization Factor} = \frac{\text{Active Rigs}}{\text{Workable Rigs (Annual Average)}} = \frac{1{,}194}{1{,}635} = 73 \text{ percent}$$

*This adjustment is based on judgments by industry representatives and various individuals in the drilling segment of the industry.

Category 1 (Existing Rigs) serves no purpose other than to show all existing rigs are not necessarily workable. Category 2 (Workable Rigs) has been adjusted through the forecast period for new construction, exports and retirements. Category 3 (Active Rigs) involves the utilization of the workable rigs and it is this count that was related to historic data to calculate rig performance indices; that is, well per rig-year and footage per rig-year for the established depth intervals.

Changes in workable rig levels through the short-range period are shown in Table 15. Information from rig manufacturers show new manufacturing will produce 135 rigs in 1974, increasing to 178 rigs in 1976. About 50 of these rigs will be used each year to equip new mobile offshore rigs, the largest percentage of which will work in foreign waters. Some exports of the remaining manufacturing capability will further reduce total rigs remaining in the United States to 59 in 1974, increasing to 70 in 1976. As shown in Table 15, these have been broken down between offshore mobile, offshore platform rigs and land. Attrition is a combination of wear out and catastrophic occurrences and is estimated at 1.5 percent per year. This reduces the net gain to the U.S. rig supply for 1974, 1975 and 1976 to 34, 44 and 45, respectively.

TABLE 15

U.S. RIG AVAILABILITY, NEW ALLOCATION AND WORKABLE RIGS

			Projected			
	1974		1975		1976	
Type and Number of New Rigs Manufactured in U.S.						
Offshore Mobile	49		50		50	
Remaining in U.S.		11		17		20
Exported		38		33		30
Fixed	86		112		128	
Remaining in U.S.		48		52		50
Exported		38		60		78
Total New Rigs Manufactured	135		162		178	
Distribution of New Rigs Remaining in U.S.						
Offshore Mobile	11		17		20	
Platform	7		8		9	
Land	41		44		41	
Total Remaining in U.S.	59		69		70	
Less:	25		25		25	
Attrition						
Offshore		2		2		2
Platform & Land		23		23		23
Net Rig Additions in U.S.	34		44		45	

This summary of changes in workable rig levels involves several assumptions. With the current accelerating demand for offshore rigs, it is worthwhile to review the assumptions regarding the forecast domestic supply of these rigs. For the short-range period, mobile rigs being constructed in the United States and not already committed to foreign service were assumed to remain in the United States. This assumption affects only a few rigs and is supported by the current increased domestic offshore leasing policy and increased crude prices. It was further assumed that no mobile rigs currently operating in foreign areas will return to the United States during the forecast period. This assumption is supported by the current high interest in foreign offshore areas, large amounts of foreign unexplored acreage under lease, and possible tax consequences for rigs returning from foreign areas. For land rigs, the possibility of increasing the number of drilling rigs exists through converting large workover rigs to perform shallow drilling operations. While it is impossible to quantify the degree to which this may occur, it is not believed to significantly affect the drilling projection. Also, well servicing activity levels are currently at near-record levels, thereby requiring full utilization of these rigs, although for fewer hours per day than if performing drilling operations.

Table 16 shows the current U.S. rigs combined with estimated net additions for the 1974-1976 period. To convert available rigs to active rigs (Hughes Rig Count), it was estimated that 86 percent of available rigs could be "making hole" at a given time in 1974. This utilization factor was increased to 87 percent in 1975 and 1976. The results for total active rigs in 1974, 1975 and 1976 would be 1,440, 1,480 and 1,520 respectively.

TABLE 16

U.S. RIG AVAILABILITY

Category	Historical 1973	Projected 1974	1975	1976
Existing Rigs	1,850			
Workable Rigs,				
End-of-Year Level	1,650	1,684	1,728	1,773
Annual Average Level	~1,635	1,667	1,706	1,751
Utilization Factor, Percent	73	86	87	87
Active Rigs, Annual Average	1,194	1,440	1,480	1,520

Similar breakdowns for each region were made considering existing and active rigs within each region. These rig breakdowns were further subdivided by drilling depth interval compatible with the previous analysis of historical data. Utilization factors varied from region to region based on historical active/workable relationships with the overall U.S. utilization factor averaging 86 percent for 1974 and 87 percent for 1975 and 1976. No individual region utilization factor was allowed to average more than 92 percent. This maximum percentage was based on an average of 8 percent "non-drilling" time which is required for rig moves, repairs, etc. Utilization factors for offshore areas were limited to a maximum of 80 percent due primarily to logistics problems. Also, utilization factors for Alaska and Pacific Offshore regions were assumed since recent history is not believed representative of future activity.

The projection of rig availability in the United States (see Tables 15 and 16) was derived through contacts with the rig manufacturing industry. It is recognized that changes in the economic and political climate will influence the actual output of rigs and obviously the distribution of those rigs. The tables do show, however, a projected allocation and utilization of domestic rigs based on the best information available and reasonable assumptions for the 1974-1976 period.

Projected Wells and Footage: 1974-1976

Projected wells and footage were calculated by multiplying the wells and footage indices adjusted for the assumed high rig utilization, by the rig availability levels. These indices were calculated for each region and depth interval. Total U.S. projections were obtained by summing the appropriate depth interval and regional results.

Table 17 shows the projected wells and footage, both successful and unsuccessful, for the United States, assuming rig availability as the only constraint. In addition to new well drilling, a small number of "old wells drilled deeper" were included to arrive at total well and footage projections. Detailed regional data by depth interval are shown in Appendix D for new well drilling. As shown in Tables 15 and 16, most of the projected drilling growth over 1973 levels could be realized in 1974 through increased utilization of existing rigs. With an existing rig supply in excess of 1,600 rigs and manufacturing capabilities of 140-180 rigs per year (of which 50-60 percent are exported and about 15 percent are required to offset attrition), additions to the overall domestic rig supply for the short-range period will be relatively small. Also, average well-depths are expected to continue the historical increase after 1974 thereby reducing the average number of wells each rig can drill annually.

TABLE 17

TOTAL WELLS AND FOOTAGE—ASSUMING DRILLING RIGS AS THE ONLY CONSTRAINT

	Historical	Projected		
	1973	1974	1975	1976
Wells				
New wells	27,023	33,700	33,700	34,000
Old wells drilled deeper	528	300	500	500
Total wells	**27,551**	**34,000**	**34,200**	**34,500**
Successful wells		21,200	21,400	21,600
Percent successful wells*		62.5	62.5	62.5
Footage (Million Feet)				
New wells	138.4	170.8	174.3	178.3
Old wells drilled deeper	.5	.3	.5	.5
Total footage	**138.9**	**171.1**	**174.8**	**178.8**
Successful footage	84	101	103	105

*Although a 62.5 percent success ratio is estimated for the projected period, the rapidly changing operating and economic conditions may cause this factor to vary between 60-65 percent.

With the rapid changes in domestic operating and economic conditions, it is recognized the overall well success ratio--that is, the percentage of the wells drilled that will be productive--may vary considerably from historical levels. It is not yet clear if the increased prices will result in a disproportionate increase in either development or exploratory type drilling. Should either of these occur, some fluctuation in the success ratio would be expected. A success ratio of 62.5 percent was used in this analysis (consistent with experience), since realistic estimates of success ratios range between 60-65 percent. While the success ratio assumption is not critical to the drilling forecast outlined in this section, it is critical in determining the tubular goods requirements outlined in Chapter Two.

Longer-Range Aspects of Materials and Manpower Requirements

The importance of a substantial expansion of industry manufacturing capability indicated by the short-range study will be realized only if manufacturers are assured that Government policies will not inhibit a continued demand for the capacity. Therefore, the long-range need for expanded equipment manufacturing capability has been examined. Long-range projections can only be directional and are sensitive to a variety of assumptions. For example, Government actions in the areas of price controls or excess profits tax could substantially limit industry activity resulting in little or no required expansion of manufacturing capability. Thus, the assumption of an attractive economic climate for the petroleum industry is a necessary prerequisite for vendors to the petroleum industry to project long-term expansion rates. The Administration has enunciated a goal of independence in energy by 1980, and in spite of present uncertainties in Washington, it is assumed that it will be implemented because of national self-interest, both political and economic.

With the assumption that the United States would work towards the long-range goal of self-sufficiency, Case I of the 1972 NPC report, *U.S. Energy Outlook*, was used as a guide to future activity levels. Case I activity levels are supported by the NPC published estimates of remaining discoverable and producible oil and are consistent with current and short-range projected activity levels (whereas current activity levels already exceed those projected for Cases II and III). Finally, Case I of the NPC *U.S. Energy Outlook* study most nearly approaches self-sufficiency levels for the United States in 1985, although even under the high-finding rate assumption of the *U.S. Energy Outlook* study report, imports are still required.

In utilizing Case I to make projections, no attempt was made to project equipment requirements in all areas of the industry. Projections were made for the required number of drilling rigs and offshore production platforms. However, the need for other items of equipment should generally conform to the projections of rigs and platforms and are vital to reach these projections.

To calculate the Case I drilling rig and platform requirements, total wells and footage data were assembled for Total United States and Offshore United States through 1985. Figures 4 and 5 show the recent footage history and projected footage for the Total United States and U.S. Offshore, respectively.

As shown in Figure 4, the short-range projection for Total United States is slightly above Case I in 1974 but falls below Case I in 1975 and 1976 due to lack of rigs. The U.S. Offshore

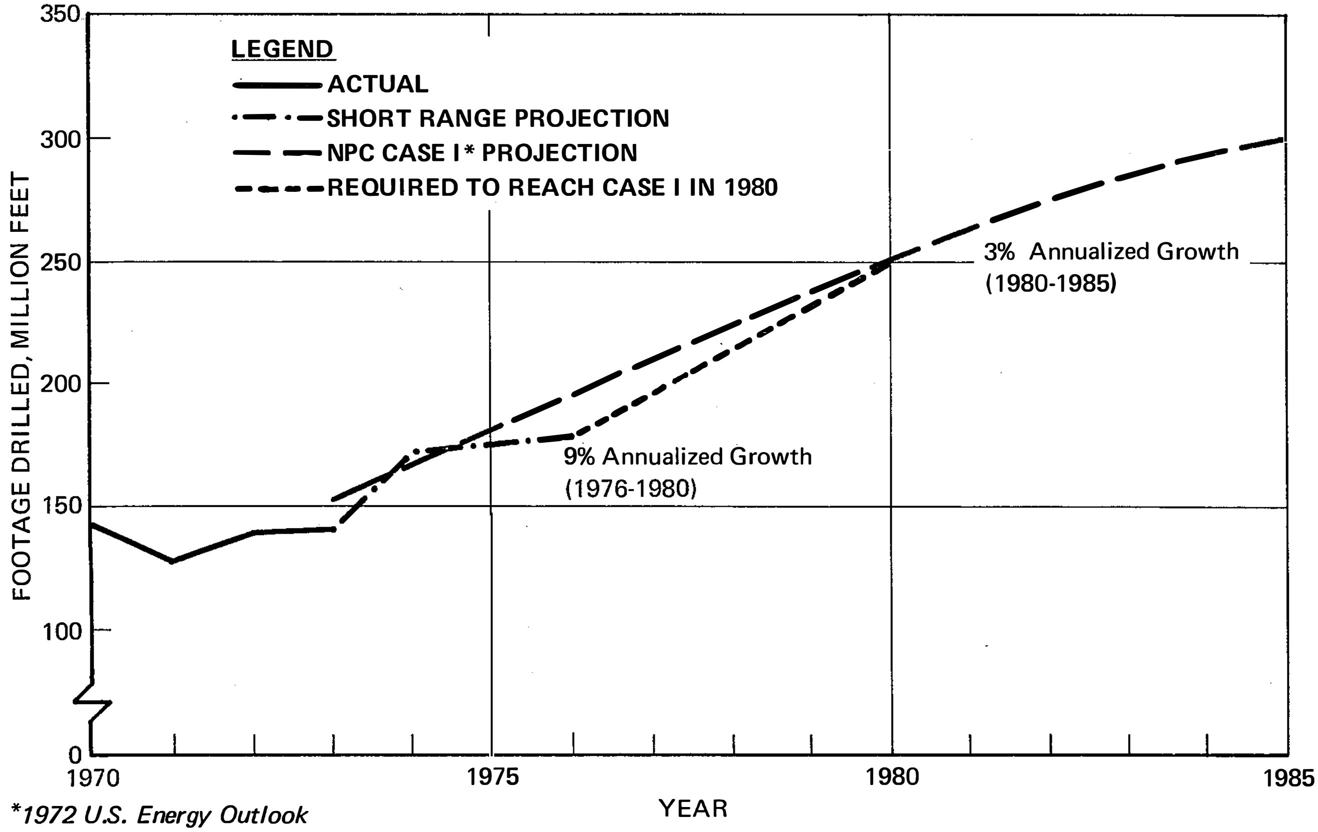


Figure 4. Total U.S.A. Projected Footage Drilled.

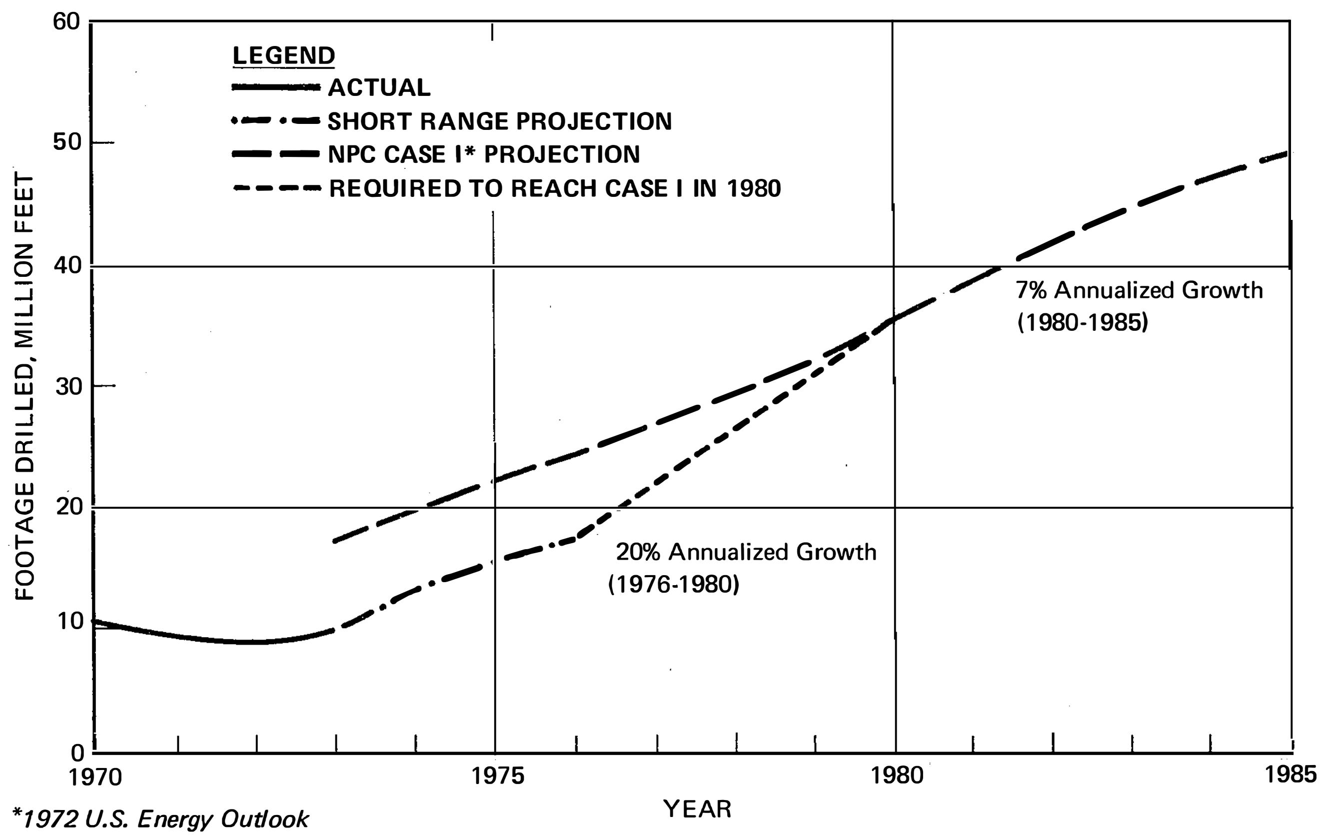


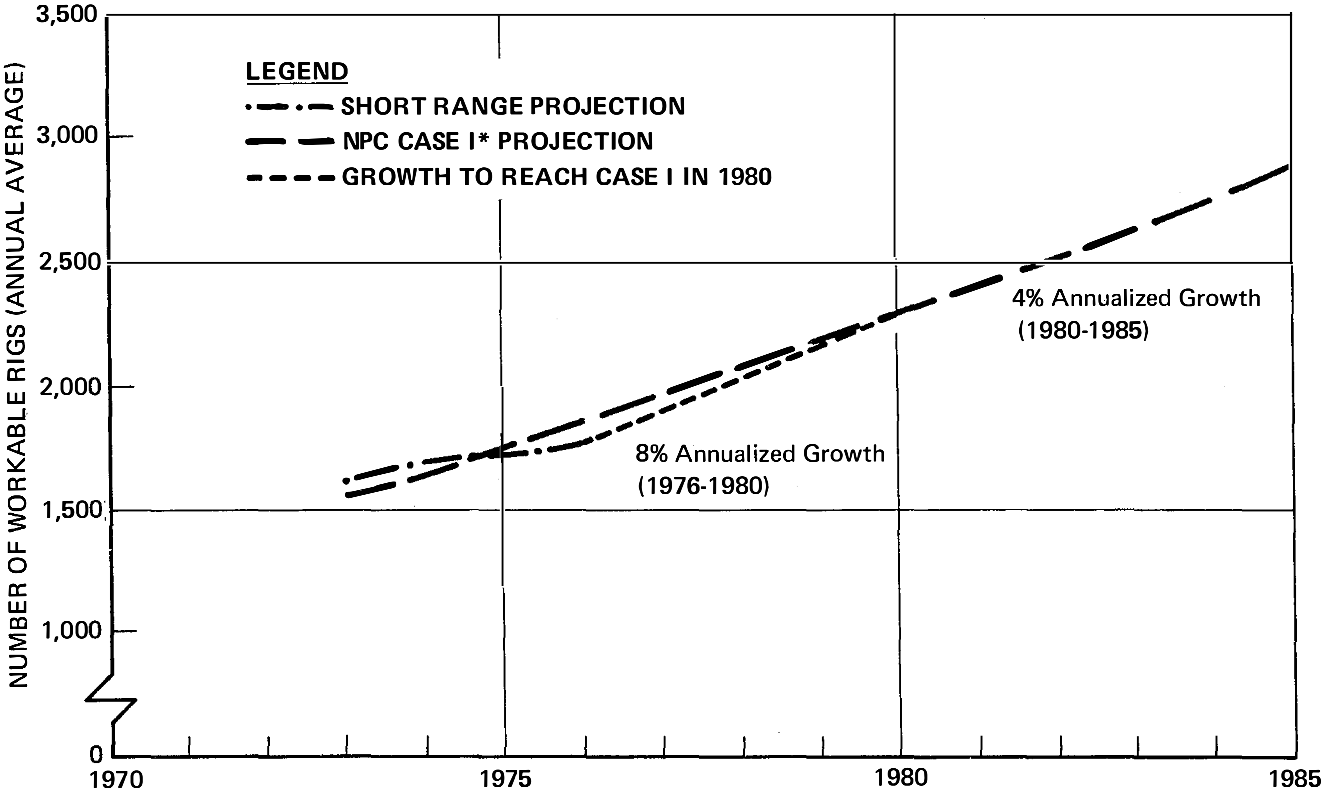
Figure 5. Offshore U.S.A. Projected Footage Drilled.

picture is considerably different, as shown in Figure 5, where the short-range projection falls some 50 percent short of the Case I projected offshore footage. The annualized growth rates for two periods shown on these figures are first, the period from 1976 (short-range projection) to 1980, and, second, from 1980-1985. This is necessary since growth rates (not absolute footage) are considerably higher before 1980 than in the 1980-1985 period. It should be noted that the growth rates shown for the 1976-1980 period are those required to go from the 1976 short-range projection to the 1980 level and do not consider the fact that the 1976 short-range level is below the 1976 NPC Case I level. In other words, the growth rates shown are those required to reach the Case I level by 1980 (even though footage drilled will fall considerably short of the NPC Case I in the 1976-1979 period).

To compute rigs required to drill the footage shown in Figures 4 and 5, the footage drilled per rig-year was assumed (consistent with experience and projected average well-depth) and required rig-years were calculated. The overall rig utilization factor was assumed to remain in the 85 percent range, while the U.S. Offshore factor was assumed to be 80 percent. Workable rigs required were then calculated through 1985, and are shown graphically in Figure 6, for Total United States, and in Figure 7 for U.S. Offshore. Again, annualized growth rates shown are those from 1976 (short-range) to 1980 and from 1980-1985. As discussed above, the growth rate shown for the 1976-1980 period is that required to realize the Case I level by 1980 and falls considerably short of NPC Case I in the 1976-1979 period.

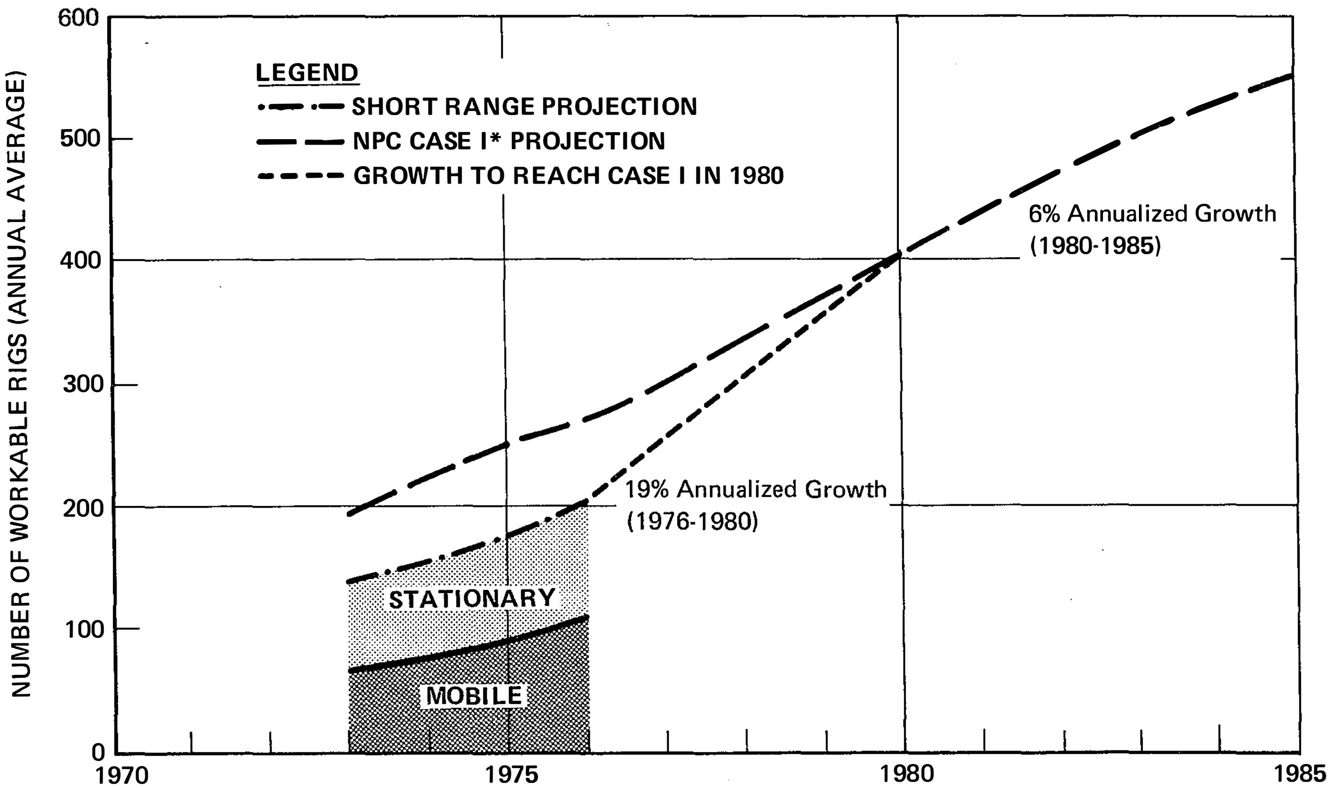
While Figures 6 and 7 show required growth in the domestic rig supply, attrition and exports must also be considered in quantifying required growth of domestic rig manufacturing capability. Attrition of the existing rig fleet was assumed to remain in the 1.5 percent per year range through 1985. Attrition of rigs to be constructed after 1976 was limited to 3-4 rigs per year for catastrophic losses. While long-range rig exports are uncertain at best, it is believed that 50 percent export of new rigs is a reasonable assumption. (Recall, the short-range projection shows exports to be 60 percent of new rigs.)

With these assumptions, growth rates in rig manufacturing capacity required to reach Case I drilling projections by 1980 and 1985 were computed. More than 30 percent per year (32 percent per year calculated) expansion is required to reach Case I (2,400 workable rigs) by 1980. A more reasonable expansion rate of 10-15 percent per year (11 percent per year calculated) would result in adequate rig capacity (2,900 workable rigs) for Case I projections in 1985. In no case do the levels of new rigs required make up the shortfall of drilling in the years that activity did not reach Case I levels (for example, see Figure 6 for 1976). In view of the foregoing, manufacturers of rigs should be encouraged to expand their capability quickly, with the assurance of high levels of demand for the entire period covered by this projection.



*1972 U.S. Energy Outlook

Figure 6. Total U.S. Required Rig Availability for NPC Case I*.



*1972 U.S. Energy Outlook

Figure 7. Offshore U.S. Required Rig Availability for NPC Case I*.

Platform requirements were calculated based on three criteria: (1) the total number of wells drilled; (2) an assumption of what percentage of these wells would be drilled from *new* platforms, i.e., platforms installed in the previous 1 year period; and (3) an assumption regarding the size of the platform, i.e., number of wells per platform. Directionally, both the percentage of wells drilled from new platforms and the number of wells per platform will increase as the industry moves to deeper waters. It was assumed that the percentage of wells drilled from new platforms would increase from some 30 percent at present to 50 percent in 1985, while the size of platforms would increase from 9-10 wells per platform at present to 17 wells per platform by 1985. These assumptions when applied to the number of new wells required for Case I offshore show platform building capacity would have to expand some 20 percent per year to reach the level of Case I by 1980. A more reasonable growth rate of 10-15 percent per year (12 percent per year calculated) would result in reaching Case I drilling rate projections in 1985. The absolute demand for platforms in the 1980-1985 period is projected to be high and, as in the case of drilling rigs, manufacturers and fabricators should be encouraged to expand their facilities quickly.

Platform fabrication capability is primarily controlled by the tons of steel per year utilized in fabricating platforms. Consequently, the projected platform demand growth rates are probably on the conservative side as the tonnage per platform is expected to increase with time, based on the following observations:

- The number of wells per platform will increase by 1985, thereby requiring somewhat larger platforms.

- Leasing has commenced in the Continental Slope of the Gulf of Mexico and is planned for deep water off Southern California. Tonnage per platform significantly increases with deep water.

- Harsh environments such as the Gulf of Alaska will require appreciably more steel tonnage per platform than industry's current designs for the Gulf of Mexico.

It is difficult to quantify the effect of the above factors since it is not known what offshore areas will be offered for leasing or where discoveries will occur. However, the composite effects of these factors could require a doubling of the projected growth rates in platform fabrication capability.

These calculations of rig and platform requirements are not precise, but show the order of magnitude of expected future activity for the petroleum industry based on plausible assumptions. It is believed these assumptions are somewhat conservative and rig and platform demand may actually be greater than results in this exercise indicate. For example, offshore leasing requirements for NPC Case I are in the range of 2-5 million acres per year, which may prove to be low in view of the Interior Department's tentative plans for substantially greater offerings of offshore acreage. Also, equipment growth rates shown are those just to *reach* NPC Case I activity levels by 1980 or 1985, and Case I activity (with the high-finding rates) does not result in United States energy self-sufficiency--even by 1985.

Chapter Two

TUBULAR STEEL

INTRODUCTION

Tubular goods demand projections for the 1974-1976 period were based on historical statistical data for 1970-1973 and the activity forecasts developed in Chapter One which assume maximum utilization of all workable drilling rigs.

Projections of supply availability were determined from information obtained from individual supply companies, Department of Commerce monthly reports of export and import shipments, and industry experience with supply sources.

DEFINITION

Tubular Goods: *Include line pipe, casing set into the well bore and tubing hung inside the casing through which hydrocarbons flow or are pumped from the reservoir to the surface. They also include drill pipe used in drilling operations.*

FINDINGS AND CONCLUSIONS

Tubular goods are and will continue to be in tight supply through 1975. Shortage of high strength casing will continue as a constraint after total tonnage production equals total tonnage demand in 1975. Principal reasons for this situation are:

- Inadequate growth in mill output to meet the increasing needs of pipe users since the economics of oil and gas production operations have improved.
- The need for operators to build up an adequate working inventory to support increased operations in the absence of steel company stocks (otherwise supplies would be sufficient in 1974).
- The residual effects of price controls on the steel industry.
- Insufficient heat treating facilities to manufacture needed high strength pipe (C-75 grade and higher).

Preliminary reports on first-half 1974 performance are that approximately 75 million feet and 15,000 wells were drilled. From this it is estimated that total new well drilling for the year will be 160 million feet and about 31,800 new wells. This means that about 11 million feet (2,200 wells) of drilling will be deferred in 1974 due largely to tubular goods shortages early in the year. The shortage was not simply in tonnage but in tubular steel available for consumption in the needed sizes, weights and grades. With the near balance between tubular goods and drill rig availability for the remainder of 1974 and 1975, further deferral of drilling due to lack of tubular steel alone is expected to be small and cannot be quantified.

The tight tubular goods situation which is projected through 1975 could be partially relieved by positive actions of both users and manufacturers.

RECOMMENDATIONS

The following actions are recommended to minimize shortages of oil country tubular goods (OCTG), both short- and long-term:

- Users casing programs should be aimed to balance the most efficient designs (minimum weight) against minimum number of sizes, weights and grades. Such designs must always follow accepted safety practices and regulatory requirements.

- The American Petroleum Institute (API) Committee on Standardization of Tubular Goods (Division of Production) should determine the most efficient sizes, weights and grades of casing needed by the domestic industry during the next few years. Development and revision of industry consensus standards is necessarily a complex process. The task would have to be given high priority if the revised standards are to be in effect in 1975. The greater potential effect is as a long-range tubular steel conservation measure.

- Steel companies' production of product mix (size, weights and grades) should be programmed to most efficiently employ their raw material supply and plant capacity (including heat treating) to meet the needs of the industry. This would include discontinuing production of a considerable amount of specialty pipe that requires resources disproportionate to the benefits (in light of total needs), and returning to production of some lighter weights (e.g., 4½ inch outside diameter [OD], 9.5 lbs. per foot and 5½ inch OD, 14.0 lbs. per foot casing) that are adequate for applications where excess weights are used today because they are all that is available.

DISCUSSION

Assumptions and Guidelines

Tubular steel for purposes of this report includes all tubular steel used by the oil and gas industry for casing, tubing, drill pipe, tool joints, drill collars and line pipe required to deliver production to the point of custody transfer of fluid hydrocarbons to a pipeline or other transporting agency.

Historical data for wells drilled in 1973 were based on API data tapes, the 1973 *Annual Quarterly Review of Drilling*

Statistics (QRDS) and the *Joint Association Survey* (JAS) published jointly by the API, IPAA and the Mid-Continent Oil & Gas Association.

The number of wells drilled in each region (regions are shown in Figure 3, Chapter One) as well as the required depths breakdown was based on the API data tapes. Wells were grouped as producing wells and dry holes with no distinction made between development and exploratory wells.

Breakdown of casing and tubing into carbon and alloy steel was based on the following:

- K-55 and lower grades--carbon steel
- C-75 and higher grades--alloy (high strength) steel

All drill pipe, tool joints and drill collars were considered to be alloy steel. All line pipe was considered to be carbon steel.

Steel requirement graphs by geographical regions for casing and tubing (Appendix E) were constructed utilizing computer casing design programs, quick design charts, and data from typical and actual designs obtained from various operators, suppliers and industry publications. Final curves were drawn using calculated curves and plotted points representing actual installations. Curves for dry holes were constructed by backing out the production casing and tubing strings from the producing well curves. Region 1A (Offshore Alaska) and Region 2A (Offshore Pacific Coast) were grouped into a single graph because of similarity of tubular design.

Based on industry practices the amount of steel used for down-hole repairs, re-drilling, deepening and casing repair jobs was developed. The value was applied as a percent to the total number of tons of casing and tubing consumed in new wells.

Guidelines developed from industry practice for line pipe were as follows:

- 3,000 wells per year placed on gas lift

  --average injection line 5 tons per well

- Service well injection lines (secondary recovery and disposal)

  --average 9.3 tons per line

- Oil well flow lines:

  --Regions 2,3,4,5,6,7,8--5 tons per well (average 2,640 feet of 2-3/8 inch OD, 3.75 lbs. per foot)

  --Regions 1A, 2A, 6A--30 tons per well (average 6,000 feet of 3 inch OD, 10.25 lbs. per foot)

--Region 1--70 tons per well (average 5,280 feet of 8-5/8 inch OD, 27.7 lbs. per foot)

- Gas well flow lines:

  --Regions 2,3,4,6,7,8--7 tons per well

  --Region 5--10 tons per well

  --Regions 1A, 2A, 6A--30 tons per well

Casing and Tubing

Statistical data for the year 1973 were developed by tabulating well count and drilled footage data by geographical region and well-depth. Geographical breakdown was based on regions defined in Chapter One, Figure 3. Well-depth breakdowns used were 0-2,500 feet; 2,500-5,000 feet; 5,000-10,000 feet; 10,000-15,000 feet and 15,000 feet and over (see Tables 55-65, Appendix E).

The next step was construction of graphs of well-depth *versus* tonnage of casing and tubing consumed in drilling and completing wells. For each region, separate graphs were constructed for producing wells and dry holes. Each graph has curves for carbon steel, alloy steel and total steel. These graphs are included as Figures 41-60 (Appendix E).

The graphs were used with the historical well data (numbers of wells and average well-depths) to determine casing and tubing steel consumption for each well type (producing wells and dry holes), geographic region and depth bracket for new wells drilled in 1973. Casing and tubing consumed in service wells were similarly determined from the curves using average depths for service wells in each region. Table 66 (Appendix E) is an itemized list of service well casing and tubing consumption by geographical region. Oil country tubular goods used for maintenance purposes in wells drilled prior to 1973 were determined from industry experience to average 4 percent of the new well consumption.

As a further aid in determining tubular consumption trends, the consumption graphs were used together with API wells and footage drilled data to calculate total tubing and casing consumption for the years 1970, 1971 and 1972. These figures are shown in Table 70 (Appendix E).

Line Pipe

Oil and gas well completions for 1973 were tabulated from the *Quarterly Review of Drilling Statistics*. Average size, weight and grade data were obtained from operators and suppliers. Using these sources of information to determine average flow line weights, line pipe consumption for flowlines was determined.

Gas lift equipment suppliers furnished their estimates of the number of wells placed on gas lift each year and the relative geographical activity levels. This information, along with industry experience on average gas lift lines, was used to estimate line pipe consumed in gas lift distribution systems.

Similarly the number of service wells drilled in 1973 as reported in the *Quarterly Review of Drilling Statistics* was used along with industry experience on average injection lines to estimate line pipe consumed in secondary recovery and disposal operations. Although small quantities were used for surface maintenance, line pipe used for replacements during 1973 was considered to be secondhand tubing and plastic or fiberglass pipe.

Drill Pipe, Tool Joints and Drill Collars

The consumption of drill pipe, tool joints and drill collars was developed as described in Chapter Three and presented in Tables 24 and 25. These figures are included in Tables 18 and 19.

Mill Shipments, Exports and Imports

The tubular steel consumed in the United States, imported and exported and domestic mill shipments are included in Tables 18 and 19. From Table 19 it can be noted that in 1973, 11.1 tons

TABLE 18

TUBULAR STEEL CONSUMED, IMPORTED AND EXPORTED—1973
(Tons)

Item	Carbon Steel	High Strength Steel	Total
Tubing, Casing and Drill Pipe	1,306,089	555,537	1,861,626
Tool Joints	0	8,019	8,019
Drill Collars	0	14,467	14,467
Line Pipe	131,975	0	131,975
Total Tubular Steel Consumed	**1,438,064**	**578,023**	**2,016,087**
Total Tubing, Casing and Drill Pipe shipped from American Mills			**1,735,892**
Less Exports			197,611
Shipped for domestic consumption			1,538,281
Imports			162,246
			1,700,527
Less shipments to operator inventories			267,000
			1,433,527
Used from inventories, unreported mill shipments, rejects, line pipe used as Oil Country Goods and use of secondhand pipe			428,099
Total Tubing, Casing and Drill Pipe			**1,861,626**

TABLE 19

DOMESTIC MILL SHIPMENTS OF OIL COUNTRY TUBULAR GOODS AND TOTAL U.S. FOOTAGE DRILLED

	Oil Country Tubular Goods Shipped* (Thousand Tons)	New Footage Drilled (Million Feet)	Tons of Oil Country Tubular Goods Shipped Per Thousand Feet of Hole Drilled
1968	1,388	149.3	9.3
1969	1,305	160.9	8.1
1970	1,219	142.4	8.6
1971	1,323	128.3	10.3
1972	1,172	138.3	8.5
1973	1,538	138.9	11.1

*The Oil Company Tubular Goods Shipped represents that shipped from U.S. mills for domestic consumption only. It does not include use from inventories, imports, unreported mill shipments, rejects, line pipe used as oil country goods, use of second-hand pipe, drill collars, or tool joints.

TABLE 20

TUBULAR STEEL CONSUMPTION—1973

(Tons)

Item	Carbon Steel	High Strength Steel	Total
Casing and Tubing	1,306,089*	514,701	1,820,790
Line Pipe	131,975	——	131,975
Drill Pipe	——	40,836	40,836
Tool Joints	——	8,019	8,019
Drill Collars	——	14,467	14,467
Total	1,438,064	578,023	2,016,087

*Includes 70,030 tons used for casing and tubing replacement for wells drilled prior to 1973.

of oil country tubular goods were shipped from domestic mills per thousand feet of hole drilled. This figure is higher than in past years, reflecting shipments of mill production plus shipments from mill stocks which were located at the steel companies in transit stocking points due to changing inventory practices; the trend toward deeper drilling and also, possibly, a shortage of lighter weights in some pipe sizes. Mill shipment figures were based on published reports of the American Iron and Steel Institute and export and import tonnages were obtained from the Department of Commerce.

The tonnage figure for the miscellaneous supply sources (use from inventory, unreported mill shipments, unidentified imports, rejects, line pipe used as oil country goods and use of secondhand pipe) is an adjustment factor which represents the difference between the calculated consumption of tubular goods and the total tonnage available for domestic consumption from reported domestic mill shipments and imports, less the increase in producer inventories. These miscellaneous sources represent a very important part (23 percent) of the current oil country tubular goods supply.

The total 1973 tubular steel consumption by types of tubular goods is itemized in Table 20. Casing, tubing and line pipe consumed by geographic region for new wells drilled in 1973 is included in Table 21. These tonnages are further broken down by various well-depth brackets within each region in Tables 55-65 (Appendix E).

Projections

Based on historical data and projected rig availability, projections of total and successful wells and footages to be drilled in 1974, 1975 and 1976 by geographic region (Figure 3, Chapter One) and well-depth breakdown were estimated as discussed in Chapter One. A success ratio of 62.5 percent was used in the calculations. Successful wells were itemized as oil, gas and service wells.

Tubular goods consumption for the years 1974, 1975 and 1976 was estimated by the same method used to determine consumption for 1973. Using Chapter One drilling projections (summarized in Table 17), in conjunction with the graphs of well-depth *versus* tonnage of casing and tubing, projections were made for consumption requirements of casing and tubing for each of the three years. Service well projected consumption by regions is detailed in Appendix E, Table 67.

TABLE 21

CASING TUBING AND LINE PIPE CONSUMED BY GEOGRAPHIC REGION FOR NEW WELLS DRILLED IN 1973

(Tons)

	Casing & Tubing		Line Pipe*	
NPC Region	Carbon Steel	High Strength Steel	Carbon Steel	Total
1	407	4,744	985	6,136
1A	809	1,312	249	2,370
2	55,966	13,010	7,142	76,118
2A	3,423	1,920	1,539	6,882
3	121,491	15,156	10,147	146,794
4	173,185	47,901	18,749	239,835
5	208,284	85,154	24,467	317,905
6	166,044	89,151	19,153	274,348
6A	151,475	144,673	14,844	310,992
7	159,436	111,421	9,684	280,541
8	195,539	259	25,016	220,814
Total	1,236,059	514,701	131,975	1,882,735

*All line pipe considered to be carbon steel.

TABLE 22

PROJECTION OF TUBULAR STEEL REQUIREMENTS

(Tons)

Item	Carbon Steel	High Strength Steel	Total Steel
	1974		
Casing and Tubing	1,644,115*	577,376	2,221,491
Drill Pipe		41,608	41,608
Subtotal	**1,644,115**	**618,984**	**2,263,099**
Tool Joints		8,518	8,518
Drill Collars		18,792	18,792
Line Pipe	160,318		160,318
Total	**1,804,433**	**646,294**	**2,450,727**
	1975		
Casing and Tubing	1,699,998†	615,394	2,315,392
Drill Pipe		43,939	43,939
Subtotal	**1,699,998**	**659,333**	**2,359,331**
Tool Joints		9,001	9,001
Drill Collars		19,332	19,332
Line Pipe	166,171		166,171
Total	**1,866,169**	**687,666**	**2,553,835**
	1976		
Casing and Tubing	1,757,887‡	668,104	2,425,991
Drill Pipe		47,382	47,382
Subtotal	**1,757,887**	**715,486**	**2,473,373**
Tool Joints		9,704	9,704
Drill Collars		20,080	20,080
Line Pipe	173,330		173,330
Total	**1,931,217**	**745,270**	**2,676,487**

*Includes 85,442 tons used for casing and tubing replacement in wells drilled prior to 1974.
†Includes 89,054 tons used for casing and tubing replacement in wells drilled prior to 1975.
‡Includes 93,307 tons used for casing and tubing replacement in wells drilled prior to 1976.

Line pipe consumed as flow lines, gas lift lines and service well injection lines are estimated using the same guidelines as were used for 1973 and are detailed by regions in Appendix E, Table 68.

Drill pipe, tool joint and drill collar consumption projections detailed in Chapter Three, Tables 24 and 25 are incorporated in Table 22.

Tubular steel requirements for 1974, 1975 and 1976 are itemized in Table 22. As was done for 1973, a value of 4 percent of the new well consumption of casing and tubing was included in the projections for replacements in wells drilled prior to that year.

Forecasts of mill shipments of oil country tubular goods for 1974, 1975 and 1976 were furnished by the steel industry and are the best estimates available at this time.

Based on Department of Commerce figures which indicated an average export tonnage of 25,000 tons per month of oil country tubular steel for the first 3 months of 1974, annual export tonnage for the next 3 years was estimated to remain constant at 300,000 tons per year.

Import tonnages from the Department of Commerce for the first 3 months of 1974 indicate an average shipment of 25,000 tons per quarter. An annual import figure of 100,000 tons per year was used for each of the next 3 years.

Table 23 presents a summarized oil country tubular steel supply and demand four-year history and projections for the years 1974, 1975 and 1976. These projections are based on the drilling of 34,000, 34,200 and 34,500 wells, respectively, in 1974, 1975, and 1976, assuming drilling rig availability as the primary constraint as discussed in Chapter One. This table indicates the supply of oil country tubular goods to be shipped from domestic mills as 2,106,000 (including 150,000 out of inventory), 2,317,000 and 2,432,000 tons respectively, for the years 1974, 1975 and 1976. These figures represent annual increases in mill shipments of 21.3 percent in 1974, 10 percent in 1975 and 5 percent in 1976.

The changing inventory situation has played a major role in the apparent sharp increase in shipments of oil country goods from the steel mills in 1973 and 1974. During the latter part of 1973, the steel companies began to liquidate the "in transit" or "down river" stocks which had for several years been relatively stable in the range of 450,000-550,000 tons. As steel company stocks were reduced, it became necessary for oil operators to increase their inventories in order to operate in an efficient and prudent manner, and maintain a tubular availability consistent with their activity level. To accomplish this goal, it has been necessary to route part of the mill shipments into operator inventories. Industry estimates indicate that steel company stocks will be reduced to the minimum level of approximately 50,000 tons by mid-1974 and that oil company inventories, approximately 367,000 tons at the end of 1973, will increase to 700,000 and 950,000 tons, respectively, at the end of years 1974 and 1975 before leveling off at approximately 1,050,000 tons during 1976. The higher inventory levels of operators as compared with the previous steel mill inventories reflects that as the number of stocking points increase, the required aggregate inventory increases disproportionately to maintain a given level of drilling activity. Additionally, since the level of activity has materially increased in 1974, inventories necessary for additional rig activity must increase.

TABLE 23

OIL COUNTRY TUBULAR STEEL SUPPLY AND DEMAND PROJECTION—CASING, TUBING AND DRILL PIPE FOR DOMESTIC DRILLING

(Thousand Tons)

	Historical				Projected		
	1970	1971	1972	1973	1974	1975	1976
Demand (Calculated consumption for History and Outlook Task Group Projection Based on Maximum Rig Utilization)	1,874	1,662	1,816	1,862	2,263	2,359	2,473
Supply							
Shipped from U.S. Mills Production	1,307	1,404	1,277	1,436	1,956	2,317	2,432
Plus shipments from U.S. Mill Inventory	——	——	——	300	150	——	——
Less exports	(88)	(81)	(95)	(198)	(300)	(300)	(300)
Plus imports	109	157	158	162	100	100	100
New Oil Country Tubular Goods (OCTG) available for domestic consumption	1,328	1,480	1,340	1,700	1,906	2,117	2,232
Consumption							
Consumption from miscellaneous sources*	546	182	476	429†	523†	492†	341†
Consumption of new OCTG	1,328	1,480	1,340	1,433	1,573	1,867	2,132
Total Consumption	1,874	1,662	1,816	1,862	2,096	2,359	2,473
Shortage (Demand less total supply consumed)	0	0	0	0	167	None‡	None‡
Domestic shipments to Pipe User Inventory	0	0	0	267	333	250	100
Inventory (Year-End)							
Pipe User Inventory	100	100	100	367	700	950	1,050
Steel Company Inventory	500	500	500	200	50	50	50
Total Inventory	600	600	600	567	750	1,000	1,100

*Use from inventory, rejects, line pipe used as oil country goods, secondhand pipe, unreported mill shipments and unidentified imports.

†Based on 1970-1972 average, 23 percent of demand assumed satisfied from miscellaneous sources. In 1975 and 1976 where "Total Consumption" equals calculated demand, consumption from miscellaneous sources may be reduced by some 53 and 230 thousand tons, respectively.

‡Annual figures indicate that by the end of 1975, supply will approach demand but there may be shortages during the year, particularly in high strength casing.

Table 23 shows the effect of the inventory change on the supply *versus* demand balance. The annual figures indicate that by the end of 1975 supply will approach demand. Inventories will continue to build slightly during 1976 to a level consonant with drilling activity. When this level is reached it will no longer be necessary to divert a portion of tubular production to inventory build-up and at this time the shortage will consist primarily of product mix--weights, grades or sizes. However, total tonnages will be sufficient to accommodate anticipated drilling activity.

In developing the data for Table 23, it was assumed that 23 percent of the total oil country tubular demand will be satisfied from miscellaneous sources--unreported mill shipments, mill rejects, imports not specifically identified as oil country tubular goods, secondhand pipe and line pipe used as oil country goods.

This figure is based on the average for the years 1970-1972 when inventories remained relatively stable. As supplies from the steel mills approach the estimated required level in 1975 and 1976, it is anticipated that usage from miscellaneous sources will be less than the historical 23 percent of total demand.

Export and import estimates were based on the assumption that tonnages would remain constant at the first-quarter of 1974 level through 1976. Historically, exports have been rapidly increasing and imports have been decreasing. A continuation of this trend would tend to prolong the tubular shortage.

While statistics indicate that sufficient tubulars will be available to accommodate the level of activity forecast for 1976, it will be late 1976 before the total supply will be sufficient to reduce consumption of converted line pipe and other miscellaneous sources significantly.

A note of explanation in regard to percent of alloy (high-strength) oil country tubular goods in the total consumption figures is in order. Steel company reports of mill shipments show the percentage of high-strength pipe to be in the range of 42-46 percent, while total domestic consumption figures indicate high-strength pipe to be in the range of 25-30 percent. Tables 69-70 (Appendix E) show the mill shipment and consumption breakdowns. The apparent discrepancy is primarily due to the large amount of pipe used from miscellaneous sources other than reported mill shipments. Table 71 (Appendix E) is an example calculation for the year 1973; when all sources of oil country tubular goods are considered, the percentage of high strength tubulars actually consumed in domestic wells is 31.0 percent. This compares favorably with the 29.8 percent calculated from the consumption charts.

The following reasonable assumptions were made for this calculation:

- Sixty (60) percent of domestic steel mill exports of oil country tubular goods are high-strength steel.
- Fifteen (15) percent of imports of oil country tubular goods are high-strength steel.
- All miscellaneous sources of oil country tubular goods are either carbon steel or are used in carbon steel applications.

Although there may be some spot shortages of line pipe during the three-year period, availability of steel line pipe for flowlines and injection lines is not expected to be a problem. A further help to the line pipe supply situation is the indication that production of plastic pipe is expected to increase. The Petroleum Equipment Suppliers Association estimates that production of plastic pipe will increase by 20 percent per year over the 1973 level in 1974, 1975 and 1976.

Chapter Three

EXPLORATION AND DEVELOPMENT DRILLING EQUIPMENT AND MATERIALS

INTRODUCTION

Exploration and development drilling operations employ a broad spectrum of equipment, materials and skills. To facilitate study, the subject was subdivided into related product groups. Principal findings and conclusions with respect to each are summarized below.

DEFINITION AND FINDINGS

Drilling Rigs: *Derricks and masts, draw works, mud pumps and tanks, blowout preventers, crown blocks, traveling blocks, wire lines, rotary tables, kelly joints, kelly drive bushings, shale shakers, electrical systems, instruments and controls, piping systems (common to all drilling rigs, onshore and offshore). Offshore rigs may be mounted on a fixed platform, drill ship, semisubmersible vessel, or a mobile bottom supported platform. Mobile structures are considered part of a mobile offshore rig.*

Findings: If sufficient steel is available to the manufacturers of masts and derricks, mud pumps and other rig components, drilling rig manufacturers project a 32 percent increase in output of drilling rigs over the period 1974 through 1976 (Table 15, Chapter One).

After consideration of probable exports of rigs, attrition and utilization factors, active drilling rigs in the United States are expected to increase by some 25 percent, from about 1,200 rigs in 1973 to about 1,500 rigs in 1976. For this level of increase, drilling personnel are not projected to be a serious constraint. However, during 1974 and to a lesser degree in 1975 while previously inactive rigs are being mobilized, the effect of inexperienced crews is indicated by projected lower average rig efficiency. Tubular goods are a constraint in 1974 with lessening effects in 1975 and 1976 (see Figure 2, Part I).

Drill Pipe and Tool Joints: *Drill pipe--Lengths (normally about 30 feet) of high strength steel tubing coupled together into a string connecting the drill bit to the kelly joint on the drilling rig. Turned by the rotary table, the string of pipe drives the bit and supplies drilling fluid into the bore hole during the drilling operation. Drill pipe is manufactured by five producers, all of whom make a full line of oil country tubular goods (casing, tubing and drill pipe).*

Tool Joints--Threaded couplings of high strength, abrasion resistant steel, welded on ends of each length of drill pipe for connecting into a string. Generally, tool joints have shorter service life than the pipe. Fabricated, installed, rebuilt and replaced by two manufacturers, neither of whom produces the basic drill pipe.

Findings: As in the case of other tubular goods (casing and tubing), drill pipe could be a constraint. If sufficient basic steel is available to the seamless pipe manufacturer, the major restraint on drill pipe production is that it competes with other oil country tubulars for heat treating and there appears to be inadequate capacity to produce the quantities that would be required if all available drilling rigs were employed. Additional heat treating facilities take about 2 years to complete from date of decision and require an additional supply of fuel, usually natural gas. Manufacturing capacity for tool joins is sufficient to meet the projected demand.

Drill Collars: *Extra thick walled sections of drill pipe made from AISI-4145H chrome-moly heat-treated bars. They are attached to the bit end of a string of drill pipe to supply the weight required for necessary cutting action.*

Findings: Since drill collars are made of heat treated alloy bars, the same constraint as described for drill pipe applies to drill collars. Sizes made from 8 inch and larger barstock are particularly in short supply.

Drilling Bits: *Rock cutting tools attached by threaded coupling to drill collars for cutting and grinding through formations in the earth's crust.*

Findings: There will be sufficient materials and manufacturing capability to meet the projected demand for drilling bits.

Drilling Fluids: *Water-based or oil-based suspensions of clays and minerals pumped into the well bore hole during drilling to seal off porous layers, equalize pressures, cool the bit and flush out the rock cuttings.*

Findings: Barite is an essential element and a major component in most drilling fluids. Since imports (from Peru, Ireland, Mexico etc.) supply nearly half of the U.S. requirements, continuity of adequate supplies is somewhat uncertain. In an emergency, low-grade deposits in Nevada could be mined if rail transport were available. Many other drilling fluid chemicals (particularly caustic soda) are also in tight supply. Total industry requirements are expected to increase with the drilling rate in the 1974-1976 period. Since drilling fluid components represent such a small part of the total U.S. chemical demand, the supply/demand balance is highly sensitive to minor changes in distribution.

Geophysical Services: *Magnetometers; gravimeters; seismic energy generators, receivers and recorders; data processing programs and equipment; and interpretation services.*

Findings: Seismic services are not expected to constrain drilling over the next few years, since much of the seismic work has already been done on the prospects that will be drilled during this period. Current and projected shortages of onshore field crews and trained technical manpower (geologists and geophysicists) for interpretation are a potential constraint. This latter problem cannot be entirely solved over the next few years.

CONCLUSIONS AND RECOMMENDATIONS

The most serious constraint to present and future expansion of drilling is shortage of basic steel for rigs, drill pipe, tool joints and drill collars. Equally important, insufficient casing and tubing could deter drilling (see Chapter Two) even though rigs and drill pipe are on hand. A major limitation on production of needed steel is heat treating capacity required for high performance materials. Worldwide supply of steel in the next few years--particularly high performance grades is expected to remain in short supply even with expanded plant capacities.

- Users can mitigate the steel supply shortage by:

  --Placing orders for actual needs only.

  --Accepting standardization of product specifications as much as possible.

  --Using operating practices that maximize drill pipe and tool joint life.

- Suppliers can mitigate the steel supply shortage by:

  --Committing sufficient mill space to production of sizes, types and grades of steel to assure the level of supply needed for optimum use of available drilling rigs.

  --Coordinating production of drill pipe with tool joint manufacturers to assure matching of sizes to needs of the industry.

- Government can assist by:

  --Establishing a long-range energy policy that will encourage suppliers to make the large investments required to expand plant capacity.

  --Taking positive actions that demonstrate its commitment to the goal of greater independence in energy.

In seismic services, because of lead time required, companies needing technically trained manpower should act now through in-house retraining, recruiting, publicity on future opportunities and collaboration with schools, to relieve the shortage that in the longer-term could impose a constraint on exploration for new reserves.

Trained manpower is not a critical factor in other parts of exploration and drilling at this point. However, the supply is tight and turnover is relatively high among drilling contractors, manufacturers and service companies. Lack of crews is not preventing the operation of drilling rigs but the increased proportion of inexperienced men employed during this period of rapid mobilization has reduced overall drilling efficiency. Any expansion in activity would be slowed by intensified problems in attracting, training and holding qualified personnel.

DISCUSSION

Drilling Rigs

In response to a survey, rotary rig makers reported plans to increase production from 135 rigs in 1974, to 162 in 1975 and 178 in 1976 (Table 15, Chapter One). A similar survey of mast and derrick manufacturers indicated projected production of these components at somewhat lower levels (130 in 1974, 138 in 1975 and 119 in 1976). However, it is believed that they can and will increase their output to match demand created by rig production (assuming the manufacturers can get the steel required) and is concluded that derricks and masts should not limit the number of drilling rigs that can be put into service in this period.

The rig manufacturers also supplied their estimates of exports for the forecast period (Table 15, Chapter One). These estimates are firm for the year 1974, but somewhat less certain for the years 1975 and 1976. The consensus of major drilling contractors surveyed was that the current percentage of new rotary rigs remaining in the United States will not increase in the 1974-1976 period due to existing contracts on rigs being constructed and the generally better profit picture for drilling contractors outside the United States. The United States must compete in the world market for petroleum equipment and services. Service companies are, by their very nature, extremely nomadic organizations that are accustomed to sudden disruptions and dislocations of their business efforts. Likewise, equipment used by these companies, particularly offshore drilling contractors, is extremely mobile. Thus, it is relatively easy for them to take their equipment and personnel into an area where the long-term demand and return on investment appears to be the brightest. Only if service contractors are convinced that the U.S. market will become stable and provide equal opportunities compared to the rest of the world will the U.S. market receive its needed share of their services.

Experts in the rig manufacturing industry estimate that 15-20 rigs per year will be scrapped during the 1974-1976 period due to obsolescence and wear-out. This is approximately 1 percent of the available rigs in the United States, and less than half the normal scrap rate. This lower estimate for the next few years recognizes that the high demand for rigs will cause extra effort and funds to be directed towards rejuvenation of old rigs and deferral of normal scrapping. Attrition due to catastrophic causes such as fire and storms is estimated at eight rigs per year. Thus, total attrition, as shown on Table 15, Chapter One, is 25 rigs per year.

Table 16, Chapter One, shows workable drilling rigs in the forecast period increasing from 1,650 at year-end 1973 to around 1,775 at year-end 1976, up about 8 percent. More significant, average active rigs are projected to go from 1,194 in 1973 to about 1,520 in 1976, up some 27 percent. This reflects an expected improvement in utilization from 73 percent in 1973 to about 87 percent in the forecast period based on:

- Experience in the first-half of 1974 when nearly 84 percent of all workable rigs were active (approaching 90 percent by the start of the third-quarter), despite restraints due to shortages of pipe and seasonal conditions that normally impede activity in the first-half more than the latter half of the year.

- The probable limit of about 92 percent activity for any region due to lost time in moving between locations (tearing down, transporting or towing between sites, rigging up, etc.).

Beyond the increased drilling capability reflected in the foregoing projections, some further capacity may result from the conversion of well servicing (workover) rigs converted to drilling (see discussion under Well Servicing, Chapter Five). There are about 3,200 workover rigs in the United States, some capable of drilling shallow wells with the addition of a drill string and minor equipment changes. There should be a good economic incentive to make this shift, since most workover rigs at present work only during daylight hours. Any resulting shortage of workover rigs could be partially overcome by adding night shifts.

Drill Pipe and Tool Joints

Demand for U.S. manufactured drill pipe and tool joints increased at a rapid rate in the years 1971, 1972 and 1973. Reasons for this include:

- Reversal of downward trend in U.S. drilling activity, necessitating replacement of drill pipe and tool joints that had been removed from idle rigs that were returned to service.

- Increased international (non-Communist world) drilling activity.

- Increased offshore drilling where due to the large number of directional holes drilled, drill pipe life is relatively short. Most offshore rigs are equipped with multiple strings of drill pipe and tool joints.

- Increased well-depths requiring more frequent inspection and culling of drill pipe and tool joints.

A continuation of the upward trend in international drilling activity, the projection of a 27 percent increase in active rigs and a 29 percent increase in footage in 1976 over 1973 in the United States indicate a sharp increase in the demand for drill pipe and tool joints.

Table 24 shows worldwide deliveries of U.S. manufactured drill pipe and tool joints for the years 1971, 1972 and 1973. Using the projection of rig activity and footages to be drilled in 1974, 1975 and 1976, the projected demand for those years is also shown. These estimates were based on the historical pattern of usage per rig-year and give consideration to the large number of new U.S. rigs to be manufactured.

U.S. drill pipe is produced by five companies, all of which are manufacturers of a complete line of oil country tubular goods. Drill pipe represents some 6-7 percent of their high strength pipe production. The heat treating of drill pipe is generally processed through the same treating equipment as high strength casing and tubing. The limitation imposed by the capacity of this equipment, plus the availability of electric furnace (alloy) steel, control the amount of drill pipe that can be made. There presently exists sufficient rolling and upsetting capacity to meet the projected demand for drill pipe. Several of the companies have announced plans for and are in the process of constructing facilities that will increase their heat treatment capabilities. However, these facilities will take about 2 years to install. Thus, there will most likely be an overall heat treating constraint through 1976.

There are two major manufacturers of tool joints in the United States. Almost all tool joints used now are attached to drill pipe by welding processes and both manufacturers have expansion programs--now practically completed--that will provide for the manufacture and attachment of tool joints at an annual rate well in excess of the projected 1976 demand. Although material spot shortages have been experienced, the manufacturers do not anticipate this will be a major problem.

Close cooperation by manufacturers in coordinating production (the matching of drill pipe and tool joints) should make it possible to meet all urgent user needs with a minimum of delay. The user can assist in accomplishing this by placing orders for actual needs only, accepting standardization of product specifications as much as possible and using sound operation practices to maximize drill pipe and tool joint life.

Drill Collars

From information reported by the principal drill collar manufacturers, the demand for drill collars in the United States has been compiled for the years 1968 through 1973. The figures are reported in Table 25. Using an average drill collar length of 30 feet and a weight of 108 pounds per foot, the footage has been converted into numbers of drill collars. From these figures, the drill collar demand per active rig per year was computed. Disregarding the years 1970 and 1971 when rig activity was low and drill collars were transferred from idle rigs, the average annual drill collar demand per active rig was 8.3 collars. Using the annual rate of 8.3 drill collars per active rig, the demand for 1974, 1975 and 1976 has been estimated. For 1970 and 1972 exports averaged 63 percent of U.S. shipments for domestic use.

TABLE 24

DEMAND FOR U.S. MANUFACTURED DRILL PIPE AND TOOL JOINTS

	U.S.				International				Totals			
Historical	Active Rigs	Drill Pipe* Tonnage	Tool Joints† Tonnage	Total Tonnage	Active‡ Rigs	Drill Pipe* Tonnage	Tool Joints† Tonnage	Total Tonnage	Active Rigs	Drill Pipe* Tonnage	Tool Joints† Tonnage	Total Tonnage
1971	976	24,479	4,913	29,392	788	21,717	4,356	26,073	1,764	46,186	9,269	55,455
1972	1,107	34,527	6,905	41,432	881	28,249	5,650	33,899	1,988	62,776§	12,555	75,331
1973	1,194	40,836	8,019	48,855	961	28,377	5,573	33,950	2,155	69,213‖	13,592	82,805
Projected												
1974	1,440	41,608	8,518	50,126	1,043	31,389	6,433	37,822	2,483	72,997	15,051	87,948
1975	1,480	43,939	9,001	52,940	1,120	34,525	7,070	41,595	2,600	78,464	16,071	94,535
1976	1,520	47,382	9,704	57,086	1,187	37,051	7,587	44,638	2,707	84,433	17,293	101,726

*High strength drill pipe averaged approximately 21 percent of total produced in 1971, 1972 and 1973.
†Tool joints are all manufactured from alloy steel. Tonnage is finished weight; raw steel required is 75 percent more.
‡Hughes Tool Company.
§Actual shipment of drill pipe in 1972 was 76,989 tons; however, only 62,776 tons were jointed and shipped to the user.
‖This includes 14,213 tons of drill pipe produced in 1972 but not jointed until 1973.

TABLE 25

DEMAND FOR U.S. MANUFACTURED DRILL COLLARS

	Historical						Projected		
U.S.	1968	1969	1970	1971	1972	1973	1974	1975	1976
Total Drill Collar Footage	302,058	310,215	207,986	199,128	281,755	267,707	358,500	368,400	378,600
Total Drill Collars	10,068	10,340	6,933	6,638	9,392	8,924	11,950	12,280	12,620
Active Rigs	1,171	1,195	1,028	976	1,107	1,194	1,440	1,480	1,520
Drill Collars per Rig per Year	8.6	8.6	6.7	6.8	8.5	7.5	8.3	8.3	8.3
Total Drill Collars Tonnage	14,389	17,165	11,463	10,956	15,222	14,467	19,400	19,900	20,400
WORLD TOTAL									
Total Drill Collars Tonnage	––	––	18,441	––	25,385	––	31,600	32,400	33,300

This ratio has been used to project world demand for U.S. manufactured drill collars as shown in Table 25.

Drill collar manufacturers generally have sufficient capacity. Delivery of drill collars varies from manufacturer to manufacturer and can range from 1-6 months or longer, depending on quantity, size and urgency. All drill collar manufacturers use AISI-4145H chrome-moly heat-treated bars for drill collars. The sources of this material are limited and availability of barstock is presently controlling the delivery of some sizes. Barstock for 8 inch outside diameter (OD) and larger collars is scarce and extended delivery is being promised by the suppliers. Material for the smaller sizes has been critical but usually available within a reasonable time. Unless some improvement in availability of barstock is seen, drill collar manufacturers will no doubt have difficulty in meeting the estimated demand rate for 1974, 1975 and 1976. At least one of the drill collar manufacturers is making a feasibility study on increasing production capability and the decision depends a great deal on material availability.

Drilling Bits

Since 1970, the total number of rock bits used in the United States has decreased approximately 20 percent, although the footage drilled per year has been almost constant. This reduction was the result of the introduction of new and improved types of compact (tungsten carbide button faced cones) rock bits, each of which replaces several of the mill cut (steel tooth cones) rock bits.

The U.S. drilling bit industry has manufactured about 240,000 bits for the world oil industry for the past several years, with 20-25 percent being exported. Figure 8 compares rock bit usage in the United States from 1970 through 1973. While total usage has declined some 20 percent, the percentage of compact rock bits has increased by approximately 75 percent and has risen from 10-20 percent of total units. By 1976, compact rock bits will represent around one-third of the units used.

Table 72 (Appendix F) gives examples of rock bit usage by depth intervals for each of the regions. For various reasons there will be areas in each region where these do not apply. They are meant to be generally representative of the area as a whole. The effect of increased compact rock bit usage is readily recognizable in the number of bits now required on the deeper wells.

A compact rock bit costs several times the price of a mill cutter rock bit. However, where it replaces three or more of the cheaper bits and eliminates costly tripping of the drill pipe, it becomes economical to the user. The compact bit was originally introduced for use in the harder formations usually encountered at greater depths. New and improved designs have made it adaptable for the softer, more easily drilled formations. There is no doubt that more such introductions will be made which will further broaden the use of the compact rock bit.

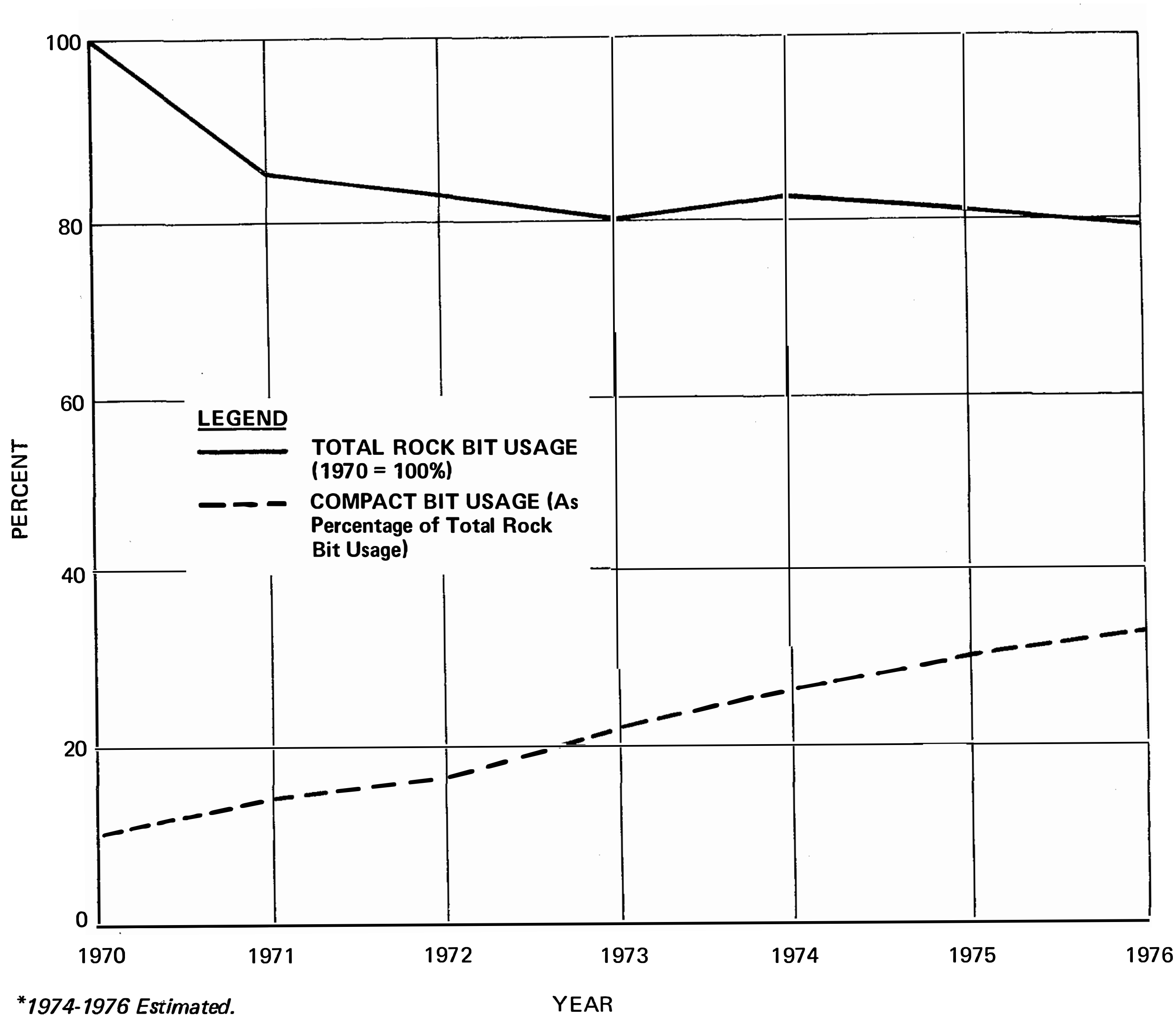


Figure 8. Comparison Rock Bit Usage and Footage--1970-1976.*

The result of this is that adequate capacity exists for the manufacture of rock bits by the U.S. manufacturers. All major manufacturers have already increased facilities for production of compact bits and are in the midst of a continuing program to further enlarge and improve these facilities.

Although there will be times when particular sizes and/or types of rock bits will be in short supply, it is generally felt that an adequate inventory will be available to meet the demand. Shortages of either or both tungsten or high-grade alloy steels used in the manufacture of rock bits could affect the availability. Some spot shortages have been experienced but to date have not caused a major problem.

As in the past, there may be times when particular sizes and/ or types of rock bits will be in short supply. But, all major manufacturers have increased facilities for production of compact bits and are in the midst of a continuing program to further enlarge and improve these facilities. Thus, barring shortages of needed tungsten and alloy steel, inventory should be available to meet the demand.

Drilling Fluids

Increased drilling programs could be restricted by tight supply of drilling fluids. During the years 1967 to 1973, average well-depth increased from 4,195 feet to over 5,000 feet, and the total number of wells and footage drilled are projected to increase by about 15 percent from 1973 to 1974.

This has placed a heavy demand on barite, a major component in most drilling fluids. In 1973, domestic production of barite provided only 53 percent of domestic consumption. The industry's need to import nearly half of its domestic requirements places it in a vulnerable position, although in a critical emergency, lower-grade deposits in Nevada could be produced if rail cars for shipment were available.

Caustic soda production has fallen behind domestic requirements and has resulted in increased lead time on delivery. Lignosulfonates, a by-product of the paper industy, face production restrictions from various pollution control laws. Availability of these chemicals is a potential constraint on additional drilling and oil production. Other chemicals for well drilling fluids that are expected to be in tight supply in 1974-1976 include: phosphates, polymers, emulsifiers, lignosulfonates, dispersants, surfactants, bactericides, and lubricants. Despite the tight supply situation proper distribution should prevent any serious constraint from these chemicals on the development of additional oil production.

Availability of various containers for mud products is a problem. Current delivery times are as follows:

Containers	Time
Bags	6 months-1 year
Drum	3-6 months
Plywood Boxes	1-6 months
Plastic	2-6 months
Box Cars	Periodic delays
Hopper Cars	Periodic delays

Projections of requirements for the various drilling fluid chemicals are shown in Appendix F (Tables 73-78). Sources of barite imported in 1973 are shown in Appendix F, Table 79.

Geophysical Surveys

Limitations on expansion of seismic services are not expected to act as constraints to accelerated drilling for the next 2 years or through 1976, since much of the seismic work has already been done on the projects that will be drilled during this period. The cyclic nature of this business is indicated by Figure 61, Appendix F.

Longer-term, the major constraint to seismic services expansion is trained technical manpower. There is currently a shortage of onshore field crews for short-term contracts, but the most serious shortage is interpretative personnel, geophysicists and geologists. Indications are that this problem cannot be entirely solved over the next few years.

Manufacturers of seismic equipment can increase production 25-50 percent per year and can stay ahead of industry's ability to man the equipment. However, tight supply on heavy trucks and boats could present problems. There is more capacity to expand field work offshore than onshore.

Suggestions for Relief of Constraints

Better utilization of existing geophysical material and manpower through better planning offers a short-term solution. Longer-term contracts can afford contractors the opportunity to efficiently schedule equipment and personnel. There needs to be better communication of job opportunities to the technically trained outside the petroleum industry. In-house retraining of individuals technically trained in other disciplines, i.e., geologists, physicists, mathematicians, etc., can be increased.

A survey of 20 petroleum companies indicates programmed geophysical activity will increase 19 percent in 1974, 15 percent in 1975 and 14 percent in 1976. No definite pattern is apparent for onshore-offshore programs. One major company plans no increase offshore but a 10 percent increase per year onshore. Another plans a 10 percent per year decrease onshore but a 300 percent increase offshore for 1974 and 30 percent per year 1975 and 1976.

Geophysical contractors and seismic equipment manufacturers were contacted regarding the constraints they foresaw relative to an all-out geophysical effort by the oil industry. The general consensus was that the potential for gathering and processing data exceeds the potential for interpreting these data.

Five of the eight seismic contractors interviewed cited field personnel as a constraint to an all-out effort for expansion. The itinerant nature of the work and the prevailing low wages, particularly for unskilled labor, undoubtedly contribute to this shortage. More money would ease the shortage of unskilled labor. Whether it would be a panacea for the shortage of dedicated nomads in the key positions remains to be seen. Estimates of the time necessary to train key field people, provided they can be found, vary from 3-6 months to 3-6 years, depending on the job.

Materials and Equipment

Two of the eight geophysical companies queried indicated equipment shortages would be the greatest constraint to their expansion.

Delivery estimates from 9-16 months on heavy trucks are mentioned as the most restrictive single item. Boats are the major constraint to expansion of marine crews. Delivery time for new boats is estimated at 2 years. Some vessels operating in foreign waters could be transferred to U.S. projects if necessary.

All seismic equipment manufacturers are accelerating their production. Spot shortages of various materials develop, but either material stockpiles or manufacturer resourcefulness have compensated for these shortages. In general, the equipment manufacturers envision no restrictions to doubling their output within 1-1½ years, given the proper planning and given the indication that the demand exists.

Manpower

All companies indicated that better planning by oil companies in reducing the cyclic nature of geophysical exploration would permit the contractors to upgrade their personnel. Better program planning including longer-term contracts would increase the efficiency and thus the output of many land crews.

Nearly all marine seismic contractors indicate that the present crews have been operating at less than capacity in past years. This is directly related to sporadic offshore lease sales in recent years. Although shortages of vessels suitable for seismic prospecting already exist, some contractors feel that marine crew availability should be adequate.

Data for seismic manpower is either unavailable or difficult to obtain for all except geophysicists and geologists. Current membership in the Society of Exploration Geophysicists (SEG) is 4,923.* Approximately 4,000 are active in the petroleum industry or related industries. Another 1,000 are estimated to be active who are not members of SEG, for an estimated total of at least 5,000.

A survey by the American Geological Institute of 53 colleges and universities, which grant degrees in geophysics, shows a rather constant enrollment for the past 4 years.† An increase, particularly in candidates for the Ph.D. degree, can be noted for 1973 over 1972. Total enrollment of seniors, Masters, and Ph.D.'s for 1973 was only 21 percent above the average for the past 3 years (Figure 62, Appendix F). A check of 10 schools indicates total enrollment for 1974 is only 10 percent above 1973--but a decrease of 10 percent at the freshman-sophomore level. Historically, about 70 percent of senior majors graduate in the year being surveyed, 25-30 percent in the entire Masters program, and about 70 percent of those in the last year of the doctoral program.‡ Applying these factors to the class of 1973, 244 new geologists were available for employment.

* Society of Exploration Geophysicists, Tulsa, Oklahoma

† AGI, *Student Enrollment in Geoscience Department*, 1972-1973, Washington, D.C.

‡ Bonnie C. Henderson, *Geotimes*, December 1972, p.20.

Past patterns indicate the petroleum industry will be able to attract about 50-60 percent of the new graduates. Assuming 60 percent, the industry added 146 new professionally trained geophysicists in 1973.

Assuming an increased need for working geophysicists of only 10 percent (500) for 1974, some of the demand will have to be filled by geologists, physicists, mathematicians, etc., who will be "retrained." This has been standard practice in the past, but "Help Wanted" ads in current industry publications indicate the demand is not filled now and certainly will not be in the immediate future.

Enrollment of geology majors in 346 degree-granting schools surveyed by the AGI shows a steady increase for the past 4 years from 15,380 in 1970 to 19,125 in 1973 as shown in Figure 63, Appendix F. Using the same method as that discussed for geophysicists, approximately 4,200 were available for employment in 1973 and about 2,400 were employed by the petroleum industry.

Chapter Four

SURFACE AND SUBSURFACE PRODUCTION FACILITIES

INTRODUCTION

The subject of surface and subsurface production facilities has been subdivided into related product groups because of the broad spectrum of equipment, materials and skills employed in production operations. Data were gathered from manufacturers through meetings, questionnaires and telephone inquiries. Primary data obtained for the 1974-1976 period include projected changes in demand, supply capability or manufacturing capacity, and magnitude of anticipated limitations with respect to raw materials, manpower and machine tools. Approximately 80 percent of the manufacturers contacted responded.

In analyzing each product group, demand for new equipment was quantified where possible. However, this was difficult in several product lines for these reasons:

- *Availability of Surplus Equipment:* Higher crude prices have extended the economic life of producing wells and, consequently, reduced the rate of abandonments and the availability of salvageable production equipment for reuse. In the past, such surplus production equipment furnished as much as 30 percent of the requirements. Any reduction in available surplus will result in a commensurate increase in the demand for new equipment. This is particularly important in the case of pumping units discussed in this chapter (and Tubular Goods, Chapter Two).

- *Product Line Mix:* In many equipment categories where shortages are not indicated in overall supply, there may be in fact deficiencies in certain categories, particularly those requiring specialized design, higher specification materials and more skilled labor in their manufacture.

- *Industry Demand as Small Percentage of Total Demand:* In many areas such as electrical equipment, the demand for oil and gas industry use is a small percentage of a broad industrial demand for these items. In these cases, the supply balance for the petroleum demand will be a function of the manufacturers' other demand levels and of how effectively petroleum operators compete for available materials that are in tight supply.

DEFINITION AND FINDINGS

<u>Fixed Offshore Production Platforms</u>: *Legs, bracing, decks, helicopter pads, ladders, walkways, landing stages, fenders, cranes, davits, superstructures, and other fixed equipment or facilities not normally removable.*

Findings: Based on the projected number of platforms to be required for the 1974-1976 period, fabricators have the plant facilities to construct these platforms. Supply of steel and availability of skilled labor are tight and represent potential constraints to expansion.

Electrical Equipment: *Field generating sets (greater than 50 kilowatt), transformers, line starters, circuit breakers, meters, conductor cable, electric motors and motor skids, all of which are used in oilfield production operations on pumping units, surface oil-water-chemical-hydraulic fluid pumps, water well pumps, small booster compressors and tank mixers.*

Findings: Oil and gas industry requirements for electrical materials and equipment represent a relatively small portion of the electrical industry output. While lead times for material deliveries are extended for 1974, shorter lead times are projected for 1975 and 1976. The electrical industry is currently facing supply problems on copper and insulation materials which could, if intensified, hold up completion of new and maintenance of existing oil and gas facilities.

Prime Movers: *Engines (gasoline, diesel, natural gas, LPG) for driving such equipment as pumping units, surface oil-water-hydraulic fluid pumps, water well pumps, small generators (less than 50 kilowatt, sump pumps and compressors.*

Findings: Manufacturers have adequate physical plant capacity. The required raw materials and skilled manpower they need could be a constraint over the short-range period.

Surface Oil/Gas Handling Equipment, Pumps and Compressors: *Oil--Valves on flow switching manifolds; oil-gas-water separators including baffles, floats and level controls; meters, safety valves, instrumentation, samplers, direct and indirect fixed heaters, water knockouts, treaters and heater treaters; tanks including valves, baffles, hatches, coils, ladders stairs, walkways; custody transfer metering units including provers, chemical pumps, and integral piping on all tanks. All centrifugal, positive displacement, worm gear, and proportioning pumps used in oilfield production operations for surface movement of fluids, for subsurface hydraulic pumping and for subsurface injection of fluids.*

Gas--Valves on flow switching manifolds, meters and meter runs, condensate and/or water separators, dehydrators, direct and indirect fired heaters, condensate measuring and metering equipment, glycol injectors, sales booster compressors including scrubbers, intercoolers, skid bases, instrumentation and integral piping on all of the above items.

Findings: Manufacturers expect growth will be fairly substantial in the 3-year period 1974-1976. Their ability to meet demand will be affected primarily by the availability of "buy-out" components, basic materials and skilled labor. No critical shortfall is currently anticipated.

Production Chemicals: *Paraffin inhibitors, emulsion breakers, and scale and corrosion inhibitors.*

Findings: Companies furnishing oilfield treating chemicals indicate that they can supply industry needs if they can get basic chemicals, some of which are now in tight supply.

Subsurface Equipment: *Packers, flow controllers, safety valves, tubing anchors and catchers, gas anchors, pump shoes, tubing check valves, erosion protection joints, movable sleeves and locking mandrels.*

Findings: Manufacturers of down-hole equipment have the plant capacity to handle industry needs. The availability of tubular goods and skilled labor could be constraining factors.

Additional Recovery Equipment: *Waterflood--Water source pumps, filters, circulating pumps, back wash and slurry tanks, mixing tanks, control equipment, meters, valves, integral piping and skids on packaged units.*

Gas Injection--Gas compressors, including intake scrubbers, inter-coolers, meter runs, manifolds, control equipment, integral piping, valves and skids.

Thermal--Water source pumps, filters, water treatment facilities, charging pumps, steam generators and fire-flood equipment including controls, safety-valve shutdowns, special wellhead equipment, skids, integral piping, metering equipment, and valves and fittings.

Findings: Suppliers furnishing waterflood and thermal equipment can meet projected demands during this time frame (which anticipate that some equipment will be salvaged from abandoned wells for use in new wells). However, compressors used for gas injection service, which represent about 5 percent of total compressor requirements, are a potential constraint due to long lead time for components (engines and gas coolers).

Artificial Lift Equipment: *Sucker Rod Pumps--Barrel tubes, liners, cages, balls, seats, and plungers.*

Miscellaneous Sucker Rod Pumping Equipment--Paraffin scrapers, pump hold-downs, rod centralizers, polished rod clamps, rod rotators, and stuffing boxes.

Pumping Units and Jacks (For Wells with Sucker Rod Pumps)--Beam pumping units (counterbalanced either by weights on beam or crank, air or hydraulic cylinders), pumping jacks, gear reducers, motor rail skids, carrier bar, surface hydraulic cylinder pumping units complete with wellhead mounting bracket, hydraulic pump and polished rod connector, and equipment guards and skids.

Hydraulic Pumping (Subsurface)--Subsurface hydraulic pumps, hydraulic fluid control equipment such as volume and pressure *controllers, wellhead lubricator and valves, seating shoe, tubing to power tubing clamps, and power tubing mandrels.*

Submersible Electric Centrifugal Pumps--Surface generators, electrical control panel, electrical cable, cable clamps, electric motor driven downhole pumps including gas separator, seals, screens, and anchors.

Gas Lift Equipment--Flow controllers, meters and intermitters, tubing landing collars, gas lift valves, collar locating mandrels, kick-off valves, blanking plugs, and check valves. Also includes wellhead plunger, catcher, tubing shoe and plunger used in plunger lift installations.

Findings: Manufacturers' capacity for furnishing gas lift equipment, centrifugal pump equipment, and hydraulic pumping equipment will be adequate to meet demands for the next 3 years.

Manufacturers of beam pump equipment are and will be operating at capacity during this time frame, with an estimated shortfall of some 10 percent in 1974. However, this estimate is highly sensitive to (1) the number of abandoned wells, (2) the re-employment of surplus pumping units, and (3) use of alternate methods of artificial lift. As in the case of other manufactured items, steel and skilled labor are potential constraining factors.

Sucker Rods: *Sucker rods, pony rods, pull rods, polished rods, hollow rods, and rod couplings. These are high tensile steel rods connected by special threads and couplings designed for high strength and resistance to wear.*

Findings: Manufacturing capacity will be adequate to meet demand through most of this 3-year period. Additional furnace, forging and threading capacities may be required in the latter year. Manufacturers are having difficulty obtaining barstock, and some labor shortages are evident but these problems are not as critical as replacement tubing for old wells.

Wellhead Equipment: *Casing and tubing landing heads and hangers, side outlet valves, stud bolts and nuts, and steel ring gaskets.*

Findings: Adequate increases in manufacturing capacities are projected during these years. Although supply problems are not anticipated, steel is involved and the currently long lead times for these items may remain at least through 1974 and 1975.

Christmas Tree Valves: *An assembly of valves used to control flow, including tubing master valves, wing valves, tees and crosses, flow controllers, adjustable and fixed chokes, and automatic shut-off valves.*

Findings: Manufacturing capability is adequate for this time frame, and requirements should be met although materials and labor will be tight.

CONCLUSIONS AND RECOMMENDATIONS

Material Shortages

The supply capabilities of manufacturers of certain categories of equipment for the base year 1973 and the 1974-1976 period were determined by contacting key manufacturers. Because of time limitations, user groups were not canvassed to develop production equipment demand projections for the 3-year period, but available statistics were used where possible.

In addition to supply capabilities or manufacturing capacity, primary data were obtained regarding manufacturing limitations as related to availability of raw materials, manpower, changes in demand and machine tools. Of the manufacturers contacted, approximately 80 percent responded and furnished the bulk of the information requested. In the course of the analysis, several major areas of concern were identified as material shortages: steel, castings and forgings, copper, and machine tools.

- *Steel:* Most of the equipment manufacturers are highly dependent on adequate supplies of steel, and without exception expressed concern over their ability to continue to obtain currently required steel supplies and, more particularly, the additional steel supplies required for indicated increases in capacity. In many cases, manufacturers' plans were predicated on maximum domestic allocations supplemented by significant imported steel supplies. Steel supplies were critical for both primary use such as plate for platform construction and surface handling facilities as well as secondary steel requirements of manufacturers and sub-suppliers furnishing buy-in materials to the primary manufacturers. Any shortfall of total steel supply requirements will cause a net reduction in the indicated capacities of various manufactured equipment segments.

- *Castings and Forgings:* All manufacturers who utilize castings and forgings identified these supplies as shortage areas--in many cases, their most critical supply item--with no foreseeable relief. Many of these manufacturers stated that exacting enforcement of OSHA and EPA regulations had caused the shutdown of many small marginally economical foundries.* These type foundries in the aggregate have historically been a significant source of supply.

- *Copper:* Manufacturers of electrical equipment identified the shortage of copper wire and the related insulated material. Bronze for bearings is also tight.

- *Machine Tools:* At the present time, machine tools have an extremely long delivery.

The above areas have the most severe potential for material shortages. Several materials, such as alloys, resins, welding rods

* OSHA--Occupational Safety and Health Administration; EPA--Environmental Protection Agency.

and stainless steel, which are used in relatively small quantities, are nonetheless critical to the delivery of the manufacturers' end product.

Manpower

Approximately 90 percent of the manufacturers indicated a concern for the availability of adequate manpower in the skilled labor areas such as welders, machinists, pipe fitters, etc. A majority of manufacturers have increased their emphasis on internal training programs to develop their own skilled labor forces. However, concern was still expressed over the available supply of qualified candidates to maintain the output of these programs at sufficiently high levels. Several manufacturers also identified shortages of engineering personnel, draftsmen and common laborers for the 1974-1976 period.

Several manufacturers, particularly those in the fabrication business, indicated that present OSHA regulations have adversely affected their productivity, requiring as much as 15 percent more manpower input. The regulations have also necessitated higher skill levels, thereby adding manpower requirements to already taxed manufacturing schedules.

Plant Expansions

In many cases the increase in manufacturing capacities identified for the 1974-1976 period is contingent upon plant expansion projects presently underway or contemplated. The ability to attain these increased capacities is contingent upon the manufacturers' timely completion of these expansions.

Manufacturers' plant capacity (existing plus planned expansions) will be adequate to meet anticipated industry demands for production equipment. However, their ability to supply needed equipment could be limited by availability of critical materials and equipment (steel, castings and forgings, copper and machine tools) and skilled manpower (welders, machinists, pipe fitters, etc.). If manufacturing shortages should develop, they are likely to appear first in items requiring custom design, higher specification materials and skilled labor.

- Industry can assist manufacturers by:

  --Advising manufacturers of long-range forecasted needs for materials and equipment.

  --Placing orders for actual needs only.

  --Insuring maximum utilization of oilfield production equipment.

  --Using standard designed material and equipment whenever possible.

--Reducing the number of change orders.

- Manufacturers can assist by:

  --Advising their suppliers on long-range needs for raw materials and components.

  --Furnishing oil industry users realistic delivery dates.

- Government can assist by:

  --Avoiding or reducing measures that impede the function of free market mechanisms and limit economic incentives.

  --Re-examining the implementation schedules of OSHA and EPA regulations in light of the tight basic material supply.

  --Implementing measures to mitigate manpower shortages, especially where special skills are needed (e.g., allowing some foreign technical personnel to work for manufacturers and energy-related companies through relaxed visa approvals, federally assisted training programs, etc.).

DISCUSSION

Fixed Offshore Production Platforms

Capabilities

Fabrication: The best estimate for 1974 yard output is 180,000-190,000 tons. Contractors indicate that present yard facilities are capable of producing approximately 200,000 tons, with steel availability cited as the primary limitation to production. Present expansion plans will increase yard capabilities over the next 2 years, so that physical plant should not be a constraint on production through 1976.

Offshore: Major platform construction vessels presently operating in the Gulf of Mexico are:

5 - 250 ton derrick barges

2 - 500 ton derrick barges

1 - 600 ton derrick barges

1 - 500 ton combination derrick pipelay barges

3 - 600 ton combination derrick pipelay barges

Assuming that the derrick barges will be capable of installing an average of 10 platforms per year and the combination barges an average of three platforms per year, the industry presently has the capability of installing approximately 80 platforms per year. This is in excess of projected demand.

Platform Requirements

Domestic platform construction for 1974, 1975 and 1976 will be mainly in the Gulf of Mexico. Wells to be drilled from fixed offshore platforms are projected to range from 607 in 1974 to 745 in 1976. An independent survey of offshore operations confirms plans for approximately 50 platforms in 1974, and a growth rate of 10 percent for 1975 and 1976 appears reasonable provided material availability and construction capacity can support that growth rate.

Estimate of Tonnage

As shown in Table 26, average water depth for a drilling platform installed in the Gulf of Mexico in 1974 will be about 175 feet, with increases of approximately 10 feet per year for the next 2 years. Table 26 also shows estimated weights for platforms and associated drilling and production equipment during this period.

TABLE 26

DEPTH AND WEIGHT OF PLATFORMS—GULF OF MEXICO 1974-1976

Projected	Average Water Depth (Feet)	Platform Weight (Tons)
1974	175	3,000
1975	185	3,200
1976	195	3,400

Assuming platform requirements to be 50 in 1974, 55 in 1975 and 60 in 1976, total fabricated platform tonnages will be:

1974	150,000 tons
1975	176,000 tons
1976	204,000 tons

To calculate total fabricated tonnage that the fabrication yards must handle, structural steel requirements for production and drilling packages should be added to these figures. These facilities could require 30,000 tons capacity in 1974 and increase at 10 percent per year. The yards, then, should be able to produce fabricated steel at the following rates:

1974	180,000 tons
1975	209,000 tons
1976	240,000 tons

Shortages

Steel: Contractors cite availability of steel as the single most critical constraint on construction of offshore platforms. Domestic steel producers are currently alloting all available tonnage to customers on the basis of purchases in previous years. Mills are running at full capacity and have been for quite some time. Although total production cannot be immediately increased, a change in product mix at various plants could increase production of certain products.

A survey of major U.S. steel producers indicates that the current lead times for the steel products (within allotments) are:

Steel Plate	4-16 weeks
Structural Shapes	6-16 weeks
Seamless Pipe	4-12 weeks
Large OD Pipe	8-10 weeks
Alloy Plate	23-33 weeks

These lead times are indicative of current demands on the steel industry. None of the steel mills contacted cited specific lead times anticipated for 1975 or 1976; however, they do indicate that worldwide demand for steel will continue to exert pressure on their existing capacities.

Consumable Materials: Consumable bulk materials used in fabrication, particularly those with steel components, are in short supply and will remain so until the demand for steel stabilizes. Advance planning and pre-purchasing of these materials are being employed to ensure continuity of construction operations.

Manpower: Construction labor on the Gulf Coast is considered tight but at present does not appear to be the limiting factor on platform production. However, this situation could be changed by a surge in petrochemical plant construction in the area, or a significant increase in platform demand.

Pedestal Mounted Cranes: Current lead time for 1975 delivery of pedestal mounted cranes is 7-18 months, and for 1976 delivery is approximately 12 months. Manufacturers have indicated that current production is limited by availability of material (75 percent effect) and labor (25 percent effect). Difficulties are being experienced in delivery of steel, engines, hydraulic components, clutches and bearings. Manufacturers report plans for increasing production of cranes in the next few years by addition of new facilities.

Anodes: These are used in jacket fabrication for external corrosion protection on that part of the platform that is immersed in sea water. Lead time is 7-8 months, with shorter delivery at premium prices. Manufacturers anticipate increasing production in 1974, 1975 and 1976 by expanding manufacturing facilities. Materials and labor cited as potential constraints on production.

Electrical Equipment

Supply Capability

Based on the information submitted, it is apparent that the majority of electrical equipment and materials manufacturers are operating at near full capacity. Companies who have plans for expanded facilities represent a small part of the market. Installation of new facilities or expansion of existing facilities will not materially affect the lead time of equipment and materials investigated during 1974-1976. The survey responses show little if any reduction in industry product demand during 1974-1976, but as shown in Table 27, some reduction in lead time due to improved manufacturing techniques is anticipated.

Material Shortages

All the companies surveyed expressed problems with material shortages. These materials include electrical steel, 1 inch plate steel, sheet metal, castings, forgings, copper, copper alloys, aluminum, silver contacts, glass, glass polyester, some porcelain items, plastics and insulating materials. Limited availability and erratic supply creates a problem in maintaining a stock of these needed materials.

Manpower Shortages

Labor in general was not expressed as a limiting factor. Some smaller companies expressed a need for supervisory personnel and skilled craftsmen.

TABLE 27

ESTIMATED DELIVERY TIMES FOR MAJOR ELECTRICAL EQUIPMENT AND MATERIALS—1974-1976

	1974 (Weeks)
Engine Generator Units:	
Over 2,000 Kilowatt	48
750 – 2,000 Kilowatt	36
Up to 500 Kilowatt	52

	1974	1975 (Weeks)	1976
Transformers:			
Specialty type	24	14	14
Load center type (dry)	28	24	24
Load center type (oilfield)	40	40	36
Distribution type (single phase)	45	45	45
Distribution type (three phase)	60	60	60
Switchgear:			
5 and 15 Kilovolts	52	52	52
600 Volts	40	40	40
Motor Control:			
Motor control center	30	30	30
Oilfield control units	30	30	30
Motors:			
Over 200 Horsepower	40	32	25
Up to 200 Horsepower	36	24	12
Wire and Cable:			
5 and 15 Kilovolt power cable	44	42	40
600 volt control cable	36	32	28
600 volt building wire	28	26	26
Raceways:			
Cable tray	12	12	12
Conduit	20	20	20
Explosion Proof Equipment	12	12	12
Conduit fittings	8	8	8
Storage batteries for control and stand-by service	18	22	22

Prime Movers

Supply Capability

Table 28 summarizes the expected annual growth in supply capabilities and the resulting capacity for producing prime movers in 1976 relative to the 1973 base year production.

Many of the manufacturers contacted indicated a significant degree of flexibility of their plant operations. Several mentioned that the supply of a particular item depends on the amount of plant space allocated to its production. Increased production of one item could often be obtained, but at the cost of reduced output of another item produced in the same plant.

TABLE 28

PROJECTED GROWTH IN PRIME MOVER SUPPLY CAPABILITY—1973-1976

Internal Combustion Engines	Supply Index	Growth (Percent Per Year)	
1973	100	—	
1974	142	42	Average = 18 percent per year compounded
1975	151	6	
1976	163	8	
Gas Turbines			
1973	100	—	
1974	220	120	Average = 49 percent per year compounded
1975	240	9	
1976	330	38	

The supply capabilities for internal combustion engines is expected to grow 18 percent per year through 1976 as shown in Table 28. Composite estimates developed from reported individual company estimates indicate gas turbine supply capabilities are expected to increase by some 49 percent yearly in the 1973-1976 period. Table 28 comments received from the survey indicate the gas turbine industry has the ability to expand its supply capabilities even more than shown in Table 28. If demand warrants the increase, about 2 years lead time would be required to provide this additional capacity. Additional supply could also be made available by allocating more plant space to the petroleum industry, which would, of course, reduce the supply to other markets.

Material Shortages

Prime mover manufacturers that responded cited castings, forgings and machine tools as the items in the shortest supply. Less frequently cited shortages included special alloy materials, bearings, clutches and radiators.

Manpower Shortages

Skilled labor was cited as an additional constraint on production.

Surface Oil/Gas Handling Equipment, Pumps and Compressors

Table 29 summarizes the expected annual growth in the supply capabilities for delivery of equipment in the years 1974, 1975 and 1976 relative to 1973 used as a base year.

TABLE 29

PROJECTED GROWTH IN SURFACE OIL/GAS HANDLING EQUIPMENT, PUMPS AND COMPRESSORS —1973-1976

	Supply Index	Growth Over Base Year (Percent)
Surface Oil Handling Equipment (Except Pumps)		
1973	100	—
1974	119	19
1975	129	29
1976	147	47
Lease Surface Pumps		
1973	100	—
1974	106	6
1975	123	23
1976	134	34
Surface Gas Handling Equipment (Except Compressors)		
1973	100	—
1974	119	19
1975	129	29
1976	149	49
Sales Gas Compressors		
1973	100	—
1974	129	29
1975	158	58
1976	163	63
Additional Recovery and Production Equipment (Thermal Equipment)		
1973	100	—
1974	143	43
1975	171	71
1976	201	101

Plant Facilities

No reporting firm stated that their present plant facilities limited their current production or delivery capability and that reported increases for 1975 and 1976 were not limited by this factor. One firm reported that it plans a limited expansion during 1974 and 1975.

Shortages

The most frequently cited cause of delivery delays was the lack of purchased finished items. In most instances, the lack of castings or forgings causes the scarcity of the purchased finished items. The reduction in the amount of steel sheets, plate and pipe received by the listed manufacturers is the reason for not being able to increase the current volume of deliveries. The reported increases in the volume of deliveries for 1975 and 1976 are contingent upon their receiving comparable increases in their receipts of raw material and finished goods over that now being received.

Manpower

The inability to increase staffing of manufacturing personnel prevents several suppliers from increasing their volume of deliveries in the current year. Some manufacturers with whom the subject was discussed reported that it was difficult, if not impossible, to hire additional skilled welders and fitters. Many of the reporting companies conduct in-house training programs to fill their requirements for skilled personnel. However, they report that it is becoming even more difficult to hire additional personnel. Areas of the country where particular difficulty is encountered include: Tulsa, Oklahoma; Houston, Texas; Los Angeles, California; Odessa, Texas; and Gulfport, Mississippi. Technical personnel, engineers and draftsmen are in short supply; however, it does not appear that this factor will limit delivery capabilities of the reporting firms.

Production Chemicals

Supply Capability

It is expected that the production chemical industry has the capability to supply the projected demand of various materials as outlined in Table 30.

Demand

The petroleum industry consumed approximately 30 million gallons of production chemicals during the year 1973, requiring an

TABLE 30

PRODUCTION TREATING CHEMICALS

	1973 Base Year	Projected Demand					
		1974		1975		1976	
	Million Gallons	Million Gallons	Percent Increase	Million Gallons	Percent Increase	Million Gallons	Percent Increase
Paraffin Inhibitors	1.5	2.25	50	3.0	35	3.6	20
Scale and Corrosion Inhibitors	13.5	16.5	22	20.0	21	24.2	21
Emulsion Breakers	15.0	17.0	13	18.5	9	19.4	5
Totals	**30.0**	**35.75**	**19**	**41.5**	**16**	**47.2**	**14**

estimated expenditure of $85 million. Table 30 shows the anticipated demand increases in these chemicals through 1976 that will result from: (1) increased exploratory activity resulting in new wells and production, and, (2) the higher prices of crude oil resulting in increased secondary and tertiary recovery projects.

Shortages

Availability could be restricted by shortages in base chemical feedstocks used for raw materials in the production chemical manufacturing processes. These include ethylene, methanol and isopropanol alcohols, phenols and amines. Aromatic solvents used to carry the inhibitors in solution and steel drums for packaging are also in tight supply.

Outlook

The production chemical industry has the manufacturing capability for current increases in volume with additional raw material available. Some additional plant capacity will be required to satisfy all projections. Plans for expansion are currently ongoing. The current shortage of raw materials appears to be a problem that can be tolerated and should not severely restrict the manufacture of products.

Subsurface Equipment

Supply Capability

The industry's capability for future expansion of plant and facilities is projected to increase manufacturing capability by 10 percent in 1974 and 20 percent in 1975. Manufacturers in this product category have the capability to supply 100 percent of the projected 1974-1976 demand. This projection is based on present commitments for new machinery and plant facilities now under construction or on order within the industry. The delivery of machine tools of the tape controlled type is currently 72 weeks and this will be a significant factor in future expansion not already committed. Steel tonnage allocations, if the present trend continues, should be adequate for these expansions with the exception of spot shortages in high alloy materials.

Demand

Subsurface equipment includes packers, tubing chokes, shut-off (safety) valves, tubing anchors and catchers, gas anchors, pump shoes, tubing check valves, erosion protection joints, flow couplings, and locking mandrels. Demand represents new wells, workover and normal replacement. Workover of wells in outer continental shelf areas that have less than 4,000 pounds per square inch (psi) surface pressure requires the addition or replacement with a remote controlled subsurface safety valve where a velocity valve was formerly used. Remote controlled safety valves are also used for certain land wells and shallow water locations.

The increase in demand for subsurface equipment for 1974 is based on extensive workover and re-completion in addition to new drilling. The increases in 1975 and 1976 primarily reflect projected increases in drilling activity. Regulations and industry recommended practices pertaining to safety and protection of the environment are also a significant factor and are reflected in the projected increases shown in Table 31.

Raw Materials

Manufacturers of subsurface equipment employ a wide variety of types of steel for raw materials. There is also a wide variation in types and sizes of finished products necessary to satisfy individual customer needs. Raw materials include a large volume of tubulars as well as barstock. Tubulars have been in short supply and some suppliers may be limited in their ability to satisfy certain customer requirements due to steel allocations and spot shortages in high alloy materials. This situation is most prevalent in flow couplings and erosion protection joints, which are purchased as tubular goods in raw material form. In some instances, orders of this type of equipment have been deferred or shut off to divert the needed raw material to other products.

TABLE 31

PROJECTED INCREASES IN DEMAND FOR SURFACE EQUIPMENT

	1973 (Base Year)	Projected Demand					
		1974		1975		1976	
	Number Items	Number Items	Percent Increase	Number Items	Percent Increase	Number Items	Percent Increase
Packers							
Permanent Packers	3,600	3,815	6	4,260	12	4,650	9
Hookwall Packers	7,470	7,920	6	8,840	12	9,650	9
Hydraulic Packers	2,270	2,410	6	2,675	11	2,930	10
Chokes and Subsurface Shut-Off Devices							
Tubing, Safety Valve (Direct Controlled, Velocity)	1,670	1,835	10	1,900	4	1,880	–1
Tubing, Safety Valve (Remote Controlled)	1,000	1,410	41	1,860	32	2,135	15
Subsurface Equipment							
Tubing Anchors and Catchers	1,420	1,575	11	1,710	8	1,860	9
Nipples and Mandrels	13,650	14,750	8	15,500	5	16,000	3
Blast Joints, Flow Couplings, and Sliding Sleeves	19,100	21,570	13	27,650	28	32,230	17

The manufacturer must maintain a large stock of raw material inventory as well as finished goods. An average of 3 months minimum working inventory of raw materials is stocked. Advance ordering and scheduling of raw materials is needed with certain high-grade alloys requiring 12-14 months for delivery.

Suppliers are currently ordering other raw materials on a 6 months in advance basis, with some materials requiring additional delivery time up to 14 months. Orders are made on the basis of the individual supplier projections of the industry's needs from experience and current industry projects. With this advance ordering, shortages may develop in size or selection of particular products. Operators may help by more flexibility in design and specifications.

Although availability of raw material is the major limiting factor to product increase, on an industry-wide basis, it is not considered critical at this time.

Manpower

The labor situation in this segment of the industry varies depending upon the location of manufacturing facilities. Plants located in areas of low unemployment have problems in manufacturing and production labor. The high demand for skilled machine tool operators creates competition among manufacturers in the area for their services. In these areas, labor could become a restricting factor. Assuming that raw materials were readily available, production of some product lines could be increased by adding additional labor shifts.

Suppliers generally train their own machinists with an extensive in-house program. Some suppliers have been more fortunate than others in labor turnover, but normal attrition and new additions require a continuing new labor supply. Labor training programs may account for as much as 20 percent of labor costs.

The increase of manufacturing capability will require the expansion of sales and service personnel in a specialized field. In order to meet this demand, there is generally a formal in-house training of employees of this type. The programs serve to train old as well as new employees. In addition, these suppliers must compete in the market place for engineers with oilfield oriented experience.

Additional Recovery Equipment

Supply Capability

The supply of waterflood and gas injection equipment is sufficient to meet projected demands. Unless there is a sharp increase exceeding the projection of new project starts, the manufacturing of waterflood and gas injection capability along with available reclaimed equipment should be sufficient to satisfy the demand.

Demand

In order to obtain a projection of requirements for additional recovery equipment, two general areas were investigated:

- The regulatory bodies of the oil producing states were surveyed to obtain a count of existing waterflood, gas injection and other additional recovery projects. Some of the states also furnished additional comments as to the pulse of the industry.

- Various manufacturers of waterflood and gas injection equipment were surveyed to determine their projection of equipment demand and their capability to supply the forecast.

Data from 14 regulatory bodies for 1970-1972 (latest available) indicate a total of 6,879 waterflood projects and 1,307 other additional recovery projects (i.e., gas injections, LPG injection, hydrothermal, and pressure maintenance (water and gas).

Recent crude oil price increases should give impetus to additional recovery projects as well as possible additions to current projects. The survey of the producing states regulatory bodies indicated anticipated increases in Alaska, Illinois, Kentucky, Michigan and New Mexico, and equipment suppliers indicated that they were receiving inquiries for waterflood equipment.

Information on gas injection compressors is limited because, except for a few major projects, compressor fabricators are not always aware that the unit will be used for injection. It is believed, however, that gas compressors for injection purposes probably represent 5 percent of the total. Many existing compressors are reclaimed and revamped by the various operators for injection use.

Shortages

The following are symptoms of tight supply in this sector:

- Castings--environmental protection regulations (air and water) have shut down several foundries and the ones remaining in business are operating under heavy load conditions.
- Bearings--such as friction bearings are being estimated at 1 year's delivery.
- Fluid ends--such as aluminum and bronze are tight.
- Engines and gas coolers--are a major constraint to compressor fabrication due to the long lead time.

- New machine tool facilities--such as tape controlled devices are being estimated as much as 2 years from order dates in some cases.

Manpower

Attrition and layoffs have reduced the work force in the industry to a small cadre and training programs are in progress to build up the work forces.

Outlook

While tight supplies will generate problems, they are not viewed as a critical potential constraint.

Artificial Lift Equipment

During 1974, according to *World Oil** forecast, approximately 15,000 wells will be placed on artificial lift. Statistics indicate that 85 percent of these will be on rod pumps, 11 percent on gas lift, 2 percent on centrifugal pumps and 2 percent on hydraulic pumping units.

The two major vendors furnishing beam pumps are booked up for 1974 and are in the process of booking orders for 1975. Demand may be reduced in light of the flexibility of using other artificial lift equipment for some applications. Another reduction to any shortfall could be realized by drawing down inventory of used rod pumps, although this is likely to provide short-term relief at best because of reduced well abandonments.

Supply Capability

Manufacturing capacity for gas lift equipment, centrifugal pumping equipment and hydraulic pumping equipment will be adequate for the next 3 years, assuming all expansion plans as indicated are completed in the proposed time frame. However, capacity for manufacturing beam pumping units is currently taxed and 1974 will be a critical year. Vendors' plants are operating at capacity and will be for the 3-year period. Projected requirements are 12,750 rod pumps for each year of the 3-year period. The supply/demand data in Table 32 assumes that 90 percent of the 7,000 pumping wells projected to be abandoned each year will have pumping units that can be salvaged for new wells.

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* *World Oil*, Vol. 178, No. 3, "Artificial Lift: Upward Trend Continues," Houston, Texas, February 15, 1974.

TABLE 32

PROJECTED SUPPLY/DEMAND FOR ROD PUMPING UNITS—1974-1976

	Number of Units 1974	1975	1976
Supply			
Manufactured	5,120	6,403	6,828
Salvaged Units	6,300	6,300	6,300
Subtotal	**11,420**	**12,703**	**13,128**
Demand	12,750	12,750	12,750
Over (Short)	(1,330)	(47)	378
	−10%	0%	+3%

Table 32 indicates a near balance between supply and demand. It should be noted that the estimated abandonment of 7,000 oil wells each year during the 1974-1976 period (6,300 salvaged units) is based on the extended economic life of marginal wells owing to higher crude prices and the consequent declining trend in abandonments (from about 25,000 in 1971 to 18,000 in 1973). If 8,500 wells were abandoned in 1974, rather than 7,000, and if the other assumed levels did not change, the projected deficit would disappear Conversely, if 7,000 wells were abandoned and only 85 percent were on rod pumps, 90 percent of which could be salvaged, the projected deficit would be about 18 percent.

Shortages

The availability of steel has caused vendors some problems. Like many manufacturers, they must now order basic materials 6-12 months in advance.

Manpower

Vendors did not indicate any significant labor shortages.

Outlook

Supply of artificial lift equipment is not expected to limit oil production although beam pumping units are a potential problem.

Sucker Rods

Supply Capability

Rod mills are fairly old and antiquated. There are currently five major suppliers of rods, which is down from eight in 1963.

The consensus of rod manufacturers is that plant capacity will approximate an annual rate of 65-67 million feet. Rod sales in 1973 totaled 51.5 million feet of which 2.3 million feet were exported. It would appear that the industry in the next 3 years will need additional furnaces, forging and threading capacity and barstock is expected to be a potential constraint to meeting demand.

Demand

Rod requirements are continuing fairly strong with one major supplier delivering rods for identified well application only and not for inventory build-up. The increase of projected oil well completions, coupled with a substantial decrease in the number of wells to be abandoned for the next 3 years will tax the production capacity of rod manufacturers.

Manpower

One mid-continent vendor has experienced some difficulty in securing skilled labor to man a full three-shift operation.

Outlook

Sucker rod supply for 1974, while tight, should be manageable with occasional temporary outages. The same is likely to continue in 1975-1976.

Wellhead Equipment

This includes casing and tubing landing heads, casing and tubing hangers, wellhead flanges, stud bolts and nuts, and steel ring gaskets. Some wellhead manufacturers also make blowout preventers used by drilling and workover rigs.

Capacity

Manufacturing capacity for wellhead equipment is projected to increase 20 percent in 1974, 10 percent in 1975 and 10 percent in 1976. Some companies have completed expansion projects in 1974, while others have expansion programs underway.

Demand

While production has increased, the demand for wellhead equipment has increased more rapidly. During 1974, back orders built up, resulting in an increase of delivery time for some wellhead equipment. Delivery of blowout preventers averaged about 2 months in 1973. By mid-1974, this had increased to over 12 months.

Material Shortages

Manufacturers are currently experiencing shortages in forgings and seamless pipe.

Manpower

The availability of skilled labor in the Gulf Coast area represents a problem to several manufacturers.

Outlook

Current projections indicate that manufacturers will be operating at capacity for each year of the 3-year period. Long lead times and some spot shortages are anticipated, but these are not likely to be a severe problem.

Christmas Tree Valves

These include tubing master valves, wing valves, steel tees and crosses, flow controllers (adjustable and fixed chokes), and differential shut-off (safety) valves.

Capacity

Manufacturers report significant expansion plans for the next 3 years.

Demand

Requirements are relatively strong as indicated by the fact that production valve deliveries are up from 8 weeks in 1973 to 20-30 weeks in mid-1974.

Material Shortages

Shortages are appearing in forgings, castings, tubing, barstock, non-standard steel plate and resin.

Manpower

Skilled labor in the Gulf Coast area is in short supply and several vendors are stepping up their training programs. One vendor indicated a possible shortage of engineering personnel and common laborers during this 3-year period.

Outlook

Capacity should be adequate to meet demand for Christmas tree valves in the 1974-1976 period.

Chapter Five

WELL SERVICING

INTRODUCTION

The well servicing industry is composed of a wide diversity of contractors and suppliers employed in petroleum drilling and production operations. In the United States in 1973, these companies employed some 140,000 people and had sales of around $4 billion. Services and materials furnished are required in (1) the drilling and completion of new wells; (2) the stimulation, repair and maintenance of existing wells; and finally, (3) the abandonment of wells after a reservoir is depleted.

Because of the diversity of size, geographical location and nature of work performed by the multitude of companies in this industry, data on activity is limited (relative to data available on drilling). Therefore, projections, at best, are extrapolations of fragmentary information, adjusted on the basis of experience and judgment of people actively involved in various segments of the business.

DEFINITION

<u>Provide Well Services and Related Engineering:</u> *Including cementing, fracturing, acidizing, well sand control, fishing for material lost in wells, directional drilling, electric and nuclear logging, perforating, artificial lift, and well workover.*

<u>Use Associated Equipment:</u> *Including production workover rigs, high pressure pumps, mixing devices, instruments and controls, electric wire line units, and many types of specialized surface and subsurface equipment, a large part of which the well servicing industry designs, assembles or manufactures.*

<u>Manufacture and Install Equipment and Supply and Inject Materials that Remain in the Well:</u> *Such as guide shoes, float collars, well casing centralizers, liner hangers, cement retainers, tubing packers, subsurface safety valves, and gas lift valves; and cement (10-15 million barrels yearly), acid (250,000 tons yearly), fracturing sand (400,000 tons yearly) and fracturing fluids.*

FINDINGS

In recent years, the well servicing industry has grown and is expected to continue to grow as shown in Table 33. Most jobs are in the $2,000-$10,000 category, but can range from $300 to repair a bottom hole pump to over $200,000 for a difficult job on an offshore well.

TABLE 33

HISTORICAL AND PROJECTED GROWTH—WELL SERVICING INDUSTRY

Historical	Average Number of Service Jobs Per Day	Percent Change *vs.* Prior Year
1969	2,640	
1970	2,535	− 4
1971	2,815	+11
1972	3,235	+15
1973	3,725	+15
Projected		
1974	4,655	+25
1975	5,820	+25
1976	7,271	+25

In the past, competition among servicing companies motivated them to maintain standby products, equipment and manpower to provide service to operators on short notice. This excess capacity has enabled them to absorb the increased demand to date, though not without scheduling problems and delays. Also, improved prices have supported repairing and returning to service older rigs of reduced efficiency. In some measure, this has been offset recently by the diversion of some workover rigs to drilling operations. This shift has been prompted by increased drilling activity (stimulated by the two-tier domestic crude pricing system) and the concomitant opportunity to use equipment around-the-clock instead of during daylight hours only (see also related discussion under Drilling Rigs, Chapter Three).

CONCLUSIONS AND RECOMMENDATIONS

With cooperation from producers, the well servicing industry will most likely accommodate the projected increase in demand through 1975. The servicing industry cannot, however, accommodate further anticipated growth in 1976 without decisions in 1974 to make substantial financial commitments for facilities and equipment needed to meet such demand. Lacking that, well servicing could be a constraint in 1976 which would delay and reduce the number of well completions and impair the ability of producers to maintain production rates from existing wells. Possible equipment constraints exist in workover rigs and to a lesser degree pump trucks and bulk handling equipment.

Actions which could help the servicing industry meet projected growth in demand are as follows:

- Producers can assist by:

  --Planning service operations and well stimulation work to give the contractor time to schedule services efficiently.

--Providing for double-shifting or 24-hour operation of workover rigs, including facilities needed for night operations, supervisory liason and rates that cover premium pay of crews.

- Contractors can assist by:

  --Reducing idle time of equipment by gearing up to operate more than one shift per day.

  --Coordinating with operators on scheduling and liaison (field supervision).

  --Equipping rigs for night operation (lights, etc.).

  --Adopting incentives to attract crews to work evening and/or morning shifts.

  --Expanding capacity in anticipation of imminent growth in and continuing high-level of demand for services.

- Government can assist by:

  --Phasing out controls on prices of crude oil and gas that make it economically unattractive to workover or recomplete old wells, deter investment in high-cost additional recovery projects and repel capital needed for expanded capacity included in the well servicing industry.

  --Relaxing local ordinances that restrict service companies to specific hours (e.g., Long Beach).

DISCUSSION

Well Servicing

Scope and Characteristics

One of the most important characteristics of the well servicing industry is that it lacks a characteristic. The flow diagrams and charts in Appendix C (Figures 10, 11, 14 and 15) illustrate the scope and diversity of functions, materials and services involved in the discovery, development and production of oil and gas fields and where service companies furnish support to operators. Individual companies provide well services, engineering, manufacturing, field installation of manufactured products, or a combination of these. Well servicing functions are required for newly drilled wells in addition to services for old wells, the entire operation of which was included in this study. Some examples of well servicing are: the cementing function, wherein a cementing pump truck and bulk handling truck that does a workover and well maintenance servicing job to repair a hole corroded in the casing may also be used on a primary cementing job clearly associated with the drilling function; or where fishing tool companies can use the same men and some of the same equipment to fish a broken pipe string out of an old well which is being repaired.

Because of the almost totally amorphous nature of the business, few, if any, recognized industry statistics are available. Virtually all study programs must be based on partially encompassing statistics, such as that furnished by Guiberson Operations and shown in Appendix G (Figures 64-69). It is necessary to factor these partial statistics upward by statistical samplings to get an estimate of the total market.

A workover can be completed for simple bottom hole pump repairs at the cost of $300 - $400 while, a difficult fishing job on an offshore well could cost from $100,000 - $200,000. The vast majority of what is termed a "job," however, is in the $2,000 - $10,000 range. Well service statistics become a multiplicity of small transactions which are difficult to obtain, rather than the larger transactions for new well drilling where complete statistical data is maintained on a national level.

Some figures which serve to define the size of the well servicing industry are:

- Approximate annual consumption of: 30,000 - 40,000 tons of steel and various alloys; 10 - 15 million barrels of cement; 250,000 tons of acid; 400,000 tons of fracturing sand; and, 500,000 - 750,000 feet of rubber hose.
- Approximate annual U.S. business volume of $4 billion
- Approximate employment of 140,000 people
- Approximate annual mileage of driving passenger cars, pick-up trucks and heavy work vehicles is between 1 - 2 billion miles.

These estimates are based on 1973 activity.

The basic growth of the total service market in the United States during the 5 year period ending December 31, 1973, appeared to be at a compound rate of 10 percent in current dollars. So that the 5 year average does not obscure the market's most recent trend, it should be noted that the increase for 1973 was estimated at 15 percent over 1972; and currently the quarter-to-quarter comparisons of 1974, as related to the predecessor 1973 quarters, indicate that another 25 percent is being added over the 1973 levels. As can be seen from these figures, the 15 percent increase noted for 1973, coupled with the additional 25 percent increase now being noted during the first part of 1974, is a dramatic change for the 5-year average ending in 1973.

Trends

Table 34 summarizes recent statistics relevant to the well servicing industry. It is important to note that the 500,000 crude

TABLE 34

ACTIVITY DATA RELEVANT TO WELL SERVICING INDUSTRY

	1969	1970	1971	1972	1973
Crude Oil Wells*	542,227	530,990	517,318	508,443	499,968
Gas Wells*	114,476	118,483	120,210	121,153	123,034
Wells on Artificial Lift†	488,004	470,249	469,809	463,143	464,101
Percent of Oil Wells on Artificial Lift	90	89	91	91	92
Crude Oil Production‡ (1,000 Bbl/day)	9,238	9,637	9,463	9,441	9,187
Number of Stripper Wells§	358,650	359,130	353,696	359,471	N/A
Stripper Well Production§ (1,000 Bbl/day)	1,246	1,209	1,160	1,129	N/A
Percent of Total Production	13.5	12.5	12.3	11.9	N/A
Stripper Wells Abandoned§	15,618	15,631	18,421	13,483	N/A
Number of New Oil Wells*	14,368	13,020	11,858	11,306	9,892
Number of New Gas Wells*	4,083	3,840	3,830	4,928	6,385
Average Depth New Wells (Feet) — Oil†	4,464	4,532	4,381	4,529	4,704
Average Depth New Wells (Feet) — Gas†	5,970	6,149	5,898	5,567	5,596
U.S. Average Crude Price at Well Head ‖ (Current Dollars Per Barrel)	$3.09	$3.18	$3.39	$3.39	$3.89
Average Number Service Jobs Per Day**	2,641	2,536	2,815	3,237	3,723

Note: N/A Not yet published for 1973.

*American Petroleum Institute, *Quarterly Review of Drilling Statistics, Annual Summary,* published annually.

†*World Oil,* Vol. 178, No. 3, "Artificial Lift: Upward Trend Continues," Houston, Texas, February 15, 1974

‡U.S. Department of Interior, *Mineral Industries Survey,* Annual Petroleum Statements, 1969-1972, Monthly Petroleum Statement, December 1973, Washington, D.C.

§Interstate Oil Compact Commission, National Stripper Well Association, *National Stripper Well Survey,* Oklahoma City, Oklahoma: IOCC, published annually.

‖Independent Petroleum Association of America, *United States Petroleum Statistics, 1974,* Washington, D.C.: IPAA, 1974.

**Estimate developed by Well Servicing Task Group.

oil and 123,000 gas wells in existence in 1973, as well as water injection wells, gas injection wells and even water source wells are candidates for well servicing. The same facilities and services were also used on the 9,902 oil wells and the 6,385 gas wells drilled in 1973. For most companies in the service business, one-half of their revenue or less comes from new wells, and this has been the case for at least 10 years.

Table 35 shows the deliveries of all types of well servicing and workover rigs for the 1968-1976 period developed by *World Oil* surveys. Seventy-three (73) percent of the new rigs delivered to date for domestic use are capable of operating at depths of over 10,000 feet. Fifty (50) percent of the rigs exported to date have this capability.

Until recently there has been little demand for new rig equipment with shallow well capabilities of 0 - 9,000 feet. The $9 per hour rig operating price would not support the cost of new pole rigs, and accordingly, this part of the market was supported by fully depreciated old pole rigs. With recent increases of operating prices for these rigs, contractors are again investing in new pole rigs.

TABLE 35

TOTAL DELIVERIES OF ALL TYPES OF WELL SERVICING AND WORKOVER RIGS

Capacities (Recommended Depth wet string 2½-inch tubing)	1968 Total	1968 Domestic	1968 Export	1969 Total	1969 Domestic	1969 Export	1970 Total	1970 Domestic	1970 Export
0 – 3,500 ft.	18	16	2	8	6	2	10	10	–
3,501 – 7,000 ft.	17	14	3	12	8	4	15	11	4
7,001 – 10,000 ft.	14	14	–	26	8	18	6	2	10
10,001 – 12,000 ft.	67	64	3	59	55	4	67	57	10
Over 12,000 ft.	31	27	4	55	45	10	24	20	4
Total All Types	**147**	**135**	**12**	**160**	**122**	**38**	**122**	**100**	**22**

Capacities (Recommended Depth wet string 2½-inch tubing)	1971 Total	1971 Domestic	1971 Export	1972 Total	1972 Domestic	1972 Export
0 – 3,500 ft.	15	15	–	10	10	–
3,501 – 7,000 ft.	18	12	6	12	10	2
7,001 – 10,000 ft.	15	8	7	25	14	11
10,001 – 12,000 ft.	66	61	5	91	76	15
Over 12,000 ft.	16	12	4	13	9	4
Total All Types	**130**	**108**	**22**	**151**	**119**	**32**

Source: *World Oil Survey*

A survey of rig manufacturers indicates that rig retirements for the 1968-1973 period have averaged 125-150 per year. This has generally matched the new deliveries, resulting in approximately the same 3,200 total number of rigs in service. However, as noted above, there has been a gradual upgrading in numbers of rigs capable of deeper well workover operations of 10,000 feet. To identify and assess potential shortages, it was projected that in 1974 and 1975 all market areas would increase 25 percent. This would mean that the 3-year period would show an increase of about 80 percent over 1972 levels (1.15 x 1.25 x 1.25 = 1.797).

Capability of Industry to Expand

1973 In Review: In scanning the markets covered by the service industry, early symptoms of potential shortages were indicated by the increasing difficulties in scheduling both manpower and materials to meet the needs or preferences of customers.

1974 Projected: With the 25-percent increase in activity levels assumed throughout 1974, tougher scheduling problems for workover rigs as well as the smaller road units for artificial lift maintenance can be expected. In 1974 the number of workover rig and rod pulling units will increase approximately 6 percent. Additionally, equipment availability will be enhanced by maintenance and repair of approximately 75 rigs that would normally be retired. These rigs will probably not be as efficient as their newer counterparts.

Another factor contributing to the workover rig short supply may be the relative attractiveness of "new" oil *versus* "old" oil as defined by the two-tier pricing system. Current estimates are that 5 - 15 percent of the workover rigs are unavailable, because they have been outfitted with power swivels or makeshift rotaries in order to drill new bore holes. From the standpoint of quick production of oil, this may be counter-productive. A well which could be worked over and put back on production within 24 hours must get in a waiting line because the rig that could do the work is out drilling a bore hole which, if productive, will not result in short-term increases in oil shipments to refineries. In spite of the increasing scheduling problems, a 25 percent growth in workover rig jobs performed could be achieved if crews worked longer hours and if oil companies tolerated the longer waits and more rigorous logistic planning.

Other items which emerged as potentially critical for the year 1974 were chemicals for fracturing, acidizing, cementing and mud systems, particularly feedstocks. The only factor that is keeping this from being a constraint at the present time is the fact that vendors to service companies realize that additional production of oil and natural gas from the United States is the only solution to the problem of their own feedstocks which are from petrochemical sources. Thus the service industry, in general, is given voluntary preferential treatment by their vendors rather than an allocation based on prior consumption

In manufacturing capacities and manufactured-product inventories, periodic shortage problems exist, but the 1974 requirements will be achieved with minimum delays in deliveries. Relative to to the drilling sector, the service industry is experiencing less difficulty in responding to demand increases since secondary recovery and workover type operations in the United States have not been as depressed for nearly as long as drilling. Thus, servicing is a healthier industry with the condition of its assets and inventories strong enough to absorb volume increased by higher asset utilization than past norms.

For those not familiar with the operation of a service fleet, or management of inventories of marketable oil field products during highly competitive time, the winner of the business often is the company who can get there first with the service unit or the product. Therefore, standby products, rolling stock and manpower have been available in order to respond to requirements in minutes or certainly in a matter of hours. Obviously, the projected level of service means that asset utilization must be expanded to cover activity through the process of keeping this standby equipment working more continuously. Accordingly, cooperation is essential since producers must now accept in days or weeks what they used to receive in hours.

This recent increase in well servicing activity for total United States and by region is shown graphically in Appendix G (Figures 64-69). The source of this data is Guiberson Operations. Oilfield Products Division, and is based upon data from 60 percent of the contractors operating 76 percent of the servicing units and workover rigs.

1975 The Critical Year: In 1975 the workover rig building industry will deliver an increase between 7 and 8 percent of new machines which will again be supplemented by not retiring approximately 75 older, less efficient units. Between these two, however, the service industry will have difficulty meeting the 25-percent growth criteria *unless* the oil companies and rig contractors will alter their practices of working daylight hours only on workover rigs. Some districts must change over to a 24-hour, 7-day work schedule if workover rigs and rod pulling units are to accomplish this 25-percent increase. This change will probably create the most critical manpower problem of any group in the service industry, since getting manpower that will work under these conditions is very difficult and can be solved only by elevated wage structures. However, if there is oil company cooperation on such a change in practice, if local municipalities will allow such work at night, and if the contractors have freedom to set wage scales high enough to attract trainable manpower, it is possible to achieve the 25-percent range.

By 1975, the available capacity for manufacturing well servicing units and other equipment will be fully utilized. Delays in future expansion could be greatly alleviated if, in the year 1974, Congress takes progressive steps in the area of energy self-sufficiency and oil pricing. If confidence existed that the long-term economic incentive exists, investment decisions in new plants could be made in mid-1974. This expansion of facilities for rig, equipment and tertiary recovery chemical manufacturing could ease the 1975 and 1976 manufacturing capacity problem. Continued oil company tolerance for lower service levels out of inventories will be required if the demand is to be satisfied with existing plant capacity through 1975.

Fabricated servicing units such as cementing trucks, electric wireline units, steel wireline, bulk mud haulers, etc., could be a secondary problem in 1975. About 10 percent more new equipment in this category can be added during 1975, and as is the case with workover rigs, retirements will be deferred in favor of refurbishment. The combination of new equipment, refurbishment, plus increased utilization, will achieve the 25-percent growth range in 1975. Increases beyond this from an improved utilization standpoint will be small and new fabrication capacity must be started in 1974 or pumping, bulking handling, wireline and electric line equipment will be in real shortage by 1976.

One area not presently a major factor which might experience some equipment shortages in 1974 and beyond, is thermal recovery. In the present light of a major resurgence of steam operations for heavy oil recovery, there could be a shortage not only of subsurface packers, pumps and expansion joints, but also a shortage of surface steam generators and water treating units.

Spotlight on Critical Path: 1974-1976

The critical path in the ability of the service industry to expand for the next three years is the availability of workover rigs and servicing units. Thus, an assimilation of additional statistical data in this area was needed. Since no universally accepted data encompassing the entire industry was available, it was necessary to compile data from a number of sources and then to extrapolate this data into the total market.

The four most universally recognized sources of information were: (1) the monthly Guiberson Operations, Oilfield Products Division, data supplied by that company's field organization; (2) the rig count made once a year by Fred E. Cooper, Inc; (3) the Association of Oilwell Service Contractors; and (4) the *World Oil Annual Study of New Workover Rig Additions*. The data from these four sources was factored up to the total market size through contacts with many rig manufacturers, contractors, contract associations, etc. The necessary factors in forecasting available workover rigs and service units for 1974, 1975 and 1976 is the determination of the expected number of additions to and the number of retirements of such equipment.

A summary of domestic service unit and workover rig projection is shown in Table 36. With these net additions to the service

TABLE 36

DOMESTIC SERVICE UNIT AND WORKOVER RIG PROJECTION—1973-1976

	Service Units and Workover Rigs	
December 1973 Total Available	3,250	
Plus 1974 Production	209	
	3,459	
Less 1974 Retirements	50	
December 1974 Total Available	3,409	+ 5%
Plus 1975 Production	242	
	3,651	
Less 1974 Retirements	50	
December 1975 Total Available	3,601	+ 6%
Plus 1976 Production	302	
	3,903	
Less 1975 Retirements	75	
December 1976 Total Available	3,828	+ 6%

fleet the past and future workover rig and service unit utilization is projected. This projection can be compared to the 25 percent increase in the projected total jobs per day to determine differences in utilization factors on the present daylight capacity and the estimated maximum capacity based on a 24-hour, 7-day week potential (shown as maximum capacity 16 hours). With these net additions to the service fleet, utilization factors must be increased through better scheduling and longer working hours to realize the projected growth rates in well servicing.

The history and projections studied are shown in Table 37. In order to reconcile this data to the Guiberson data, it must be recognized that the Guiberson data shows a rig as being active even though it may operate only 3 hours during the day. Therefore, in order to make a transition from the Guiberson data, a dimension of time must be added since the Guiberson utilization only shows the percentage of the rigs that were active in any one day and does not deal with the question of how long they were active.

To ascertain from service contractors how long rigs can be kept operational under the present daylight system and how long they can be kept operational under the 24-hour, 7-day week basis, definite ceilings were determined because of scheduling and maintenance time requirements. Scheduling workover rigs is quite different from scheduling a drilling rig since a drilling rig, once on a job, will remain there quite some time. A rod pulling unit servicing shallow wells may move from two or three, and sometimes even four, locations a day if it is operating on a 24-hour basis. However, workover units may also encounter waiting

TABLE 37

SERVICE UNIT AND WORKOVER RIG UTILIZATION

	Historical					Projected		
	1969	1970	1971	1972	1973	1974	1975	1976
Average Operating (Hours Per Rig Per Day)	5.4	5.2	5.8	6.7	7.6	9.1	10.8	12.7
Average Jobs Per Rig Per Day (6½ hours average)	.84	.80	.89	1.03	1.17	1.40	1.66	1.95
Total Rigs Available (Year-End)	3,159	3,152	3,167	3,114	3,250	3,409	3,601	3,828
Average Rigs Available During Year	3,150	3,155	3,159	3,141	3,182	3,330	3,505	3,714
Total Jobs Per Day	2,641	2,536	2,815	3,237	3,723	4,654	5,817	7,271
Percent Potential								
Daylight Capacity (10 hours)	54	52	58	67	76	91	108	127
Maximum Capacity (16 hours)	34	33	36	42	48	56.9	67.5	79.4

periods where the job is delayed thereby resulting in no work for 24 or 48 hours.

As a result, the following assumptions were used as to the limiting capacity in any one day as a servicing unit:

- The limiting usable time on present daylight practices is 10 hours per day. This is as tight as the daylight hours can be scheduled since other service contractors also must be called out and simultaneously scheduled.

- When operating 24 hours per day, 7 days a week, there is a limiting capacity of 16 hours per day due to the following:

  --Breakdowns (men and machines)

  --Servicing equipment

  --Scheduling and logistics

  --Local laws against Sundays and 24 hour days.

One other key bit of information which was obtained on a spot-study basis is that the average length of a single job in this type of business is about 6.5 hours. This was obtained by using the billing time from service units and averaging a number of jobs with different lengths to find the average length of a job, and was also found to have been relatively static over recent years. Accordingly, it was used as a constant in computing the increased workloads. With the increasing workloads, inexperienced work crews will be used which will cause inefficiencies on the job. However, a countering force would be that of radio dispatching. Travel time could be saved by moving directly from location to location without a return to the contractor's storage yard.

In summary, the industry should make it through 1974 on its present daylight type utilization. But by 1975, operations must shift over, in the critical geographical areas where constraints are occurring, to the 24-hour type operation. Otherwise, the 25-percent increase assumed by the study will not be attained. It is believed that extended hours of operation are advisable and should and can be implemented.

The shift to 24-hour utilization would also help in other critical sectors, such as fracturing and acidizing trucks since they are tied up overnight quite often because the rig crew works only daylight tours. Consequently, this shift will help materially in the equipment utilization in the other critical areas of the service industry.

Chapter Six

GAS PROCESSING PLANTS

INTRODUCTION

Projections relating to gas processing plants were based on analyses of trends in each of the inland regions having gas production. Principal sources of data were the annual "Surveys of Gas-Processing Plants" reports and input from industry individuals.

DEFINITION

Gas Processing Plants: *Extract the high molecular weight hydrocarbons from raw gas produced from oil and gas wells. Operations include compression, refrigeration, fractionation and treatment. These gas plant end products are transferred from the plants to liquid and gas transmission lines. Some dry gas may be returned to hydrocarbon-bearing formations to maintain pressures or assist in additional oil recovery.*

FINDINGS

In recent years, natural gas production in the United States has run in the range of 22-23 trillion cubic feet yearly (TCF/YR) (60 billion cubic feet daily [BCF/D]). This is 2-3 times the rate of discovery of additional gas reserves. Despite strong demand, production in the foreseeable future probably will not rise above the 1973 level. A decline from 1973 levels, in fact, is projected. Even with declining production, under present price controls there is little likelihood that discoveries will offset the drawdown of existing reserves. Even in a free market, the adverse trend could not be reversed in the 1974-1976 period because of the lead times required for exploration and development requirements to generate additional reserves.

Gas processing plant capacity in the United States reached a peak of about 75 BCF/D in 1971. Since then, although existing capacity has been scrapped faster than new capacity has been added, plant utilization has run less than 80 percent. In recent years, new plant construction has accounted for just over one-half of new capacity added. Expansion of existing plants accounted for the remainder. New plants are predominately cryogenic, tuboexpander, skid-mounted units erected near producing fields. They have typically averaged about one-third the capacity of existing plants (e.g., about 32 MMCF/D average for all plants).

* *Oil and Gas Journal*, Surveys of Gas-Processing Plants reports, (compilation of data for many years).

CONCLUSIONS

Carbon steel requirements for gas processing are expected to range between 250,000-260,000 tons yearly in the 1974-1976 period. About 90 percent of this is for gas gathering systems, with the balance for new plants, expansions and maintenance to existing plants, and compressors. While the needs are small compared to other sectors, steel for gas processing could become a constraint if adequate steel manufacturing is not available.

Fabricated equipment is not likely to be a constraint, although lead time for some essential items such as heat exchangers, process vessels and engines now exceeds 40 weeks. Competing demand for these and other commonly used items (e.g., heaters, pumps, motors, instruments and controls) by refineries, petrochemical plants, fertilizer plants and other industries could bring such equipment into the critical range.

Because the number of gas plants is declining and new plants are simpler to run, operating manpower is not expected to be a problem. However, as with other sectors, construction manpower could become a problem, owing to a general shortage of personnel, particularly engineers and draftsmen.

Capital could become a critical factor in providing for projected gas processing plant construction. New plants and expansions will depend on:

- Minimum interference with free market mechanisms
- A regulatory climate that permits prices of gas plant products to seek levels competitive with other fuels and reflect increased costs of feedstock, labor and construction.

DISCUSSION

Gas Processing History

Recent gas processing plant trends were examined in detail for each of the eight inland NPC regions (Figure 3, Chapter One). Table 38 shows these trends for the total United States. Regional detail is shown in Appendix H (Tables 80-87). The annual Surveys of Gas-Processing Plants were the principal source for this information.

Total Capacity

Gas processing plant capacity in the United States reached a peak of 74.5 BCF/D in 1971 and declined to 73.8 BCF/D in 1972. A small increase in capacity was registered in 1973 because an unusually large (900 MMCF/D) gas plant came on stream, which more than offset capacity declines from other plants. No extra large gas plants are expected for the 1974-1976 period. Existing capacity is being scrapped faster than new capacity is being added.

TABLE 38
GAS PROCESSING—UNITED STATES

Historical	Plant Capacity Annual Average	Plant Throughput (MMCF/D)	Percent Capacity	Liquid Products (MGAL/D)	(GAL/MCF)	Capacity Added			Capacity Deleted (MMCF/D)	Net Capacity (MMCF/D)
						New Plants	Expansions (MMCF/D)	Total		
1970	73,326.2	59,139.8	80.7	75,433.4	1.3	3,297.3	2,200.7	5,498.0	2,509.7	2,988.3
1971	74,482.8	58,792.4	78.9	76,150.9	1.3	546.0	1,539.3	2,085.3	2,406.3	(321.0)
1972	73,814.9	56,240.7	76.2	77,220.4	1.4	1,075.8	397.0	1,472.8	2,480.2	(1,007.4)
1973	73,877.9	55,910.8	75.7	75,316.3	1.3	1,390.9	2,093.0	3,483.9	1,946.7	1,537.2

Older, more inefficient plants are being abandoned rapidly as liquid recovery declines to minimum levels or increases in recovery efficiencies are justified by building new plants. Capacity is being scaled down at some existing plants by removing worn out equipment.

Most of the gas plant capacity is near the producing fields in the Southwest and Southeastern regions of the United States. The Texas and Louisiana Gulf Coasts accounted for almost 40 percent of U.S. capacity in 1972. At the end of 1973, a total of 757 gas plants were operating, with an average capacity of almost 100 MMCF/D. A summary is shown in Table 39 by NPC Regions.

TABLE 39

EXISTING GAS PROCESSING PLANTS AS OF JANUARY 1, 1974

NPC Region	Number Gas Plants	Average Plant Size (MMCF/D)
1	2	30.0
2	44	38.3
3	66	54.5
4	144	94.0
5	164	55.3
6	212	100.1
7	114	202.1
8	11	183.0
Total	757	98.0

Plant Throughput

The amount of gas processed at plant is dropping more rapidly than plant capacity. The ratio of plant throughput to plant capacity has steadily fallen from 80.7 percent in 1970 to 75.7 percent in 1973 (Table 38). Many plants have the capability to process substantially more gas because of this spare capacity. In the larger producing regions, the operating ratio in 1973 ranged from 64.7-88.5 percent.

New Capacity

The amount of new capacity that is added fluctuates widely--ranging from 5.5 BCF/D in 1970 to only 1.5 BCF/D in 1972 (Table 38). Gas processing has grown faster than gas production in the last 10 years because in earlier years, a portion of existing gas streams was not processed. The gas processing industry is now processing nearly all the gas supply that can be economically justified. New capacity additions will be tied closely to new gas streams and the quality of these streams. Also, some new capacity is for replacement of obsolete plants.

New plants accounted for slightly more than one-half of new capacity added in 1970-1973 period, with expansions at existing plants accounting for the remainder. These new plants are much smaller than the average of existing plants. As shown in Table 40 (see Appendix H, Tables 88-91 for regional detail), new plants averaged only 31.5 MMCF/D during the 1971-1972 period, compared to the average of almost 100 MMCF/D for all existing plants in 1973. The average new plant size was inflated in 1973 because of the extra large plant mentioned earlier.

TABLE 40

NEW GAS PROCESSING PLANTS IN THE UNITED STATES FROM 1971-1973—CAPACITY END-OF-YEAR
(Million Cubic Feet per Day)

Plant Capacity (MMCF/D)	1971 Number Plants	1971 Total (MMCF/D)	1971 Average (MMCF/D)	1972 Number Plants	1972 Total (MMCF/D)	1972 Average (MMCF/D)	1973 Number Plants	1973 Total (MMCF/D)	1973 Average (MMCF/D)
0-20	16	194.0	121.1	14	140.2	10.0	19	190.9	10.0
21-50	5	183.0	36.6	11	365.6	33.2	5	165.0	33.0
51-100	4	237.0	59.3	5	420.0	84.0	2	135.0	67.5
Over 100	1	125.0	125.0	1	150.0	150.0	1	900.0	900.0
Total	26	739.0	28.4	31	1,075.8	34.7	27	1,390.9	51.5

The amount of new capacity is predominately along the Gulf Coast, expecially Louisiana. Regions 6 and 7 accounted for 79 percent of all new capacity added in the 1970-1973 period, with South Louisiana contributing almost one-half of the U.S. total. Also, capacity deleted in Louisiana averaged only 20 percent of the U.S. total during that period.

Liquids Recovery

Additional material requirements will be placed on existing plants because of more complete extraction of ethane, which is projected to rise from 0.21 gallons per thousand cubic feet of gas (GPM) in 1972 to 0.30 GPM in 1976 if economic conditions permit. Propane and heavier products rise gradually from 1.09 GPM in 1972 to 1.20 GPM in 1976. More complete extraction of ethane also produces some incremental propane and will increase slightly the average GPM of this product.

Because of declining gas production, ethane production is projected to level out at 13.7 million gallons daily in 1976 in spite of the more complete extraction. Propane and heavier products production will decline from 61.5 million gallons daily in 1972 to 53.7 million gallons daily in 1976.

Future New Gas Production and Processing Capacity

The future amount of new gas processing capacity can be estimated by extrapolating new gas production and estimating the portion that will be processed. One method of extrapolating new gas production is derived by estimating new gas reserve additions and assuming a production rate for these reserves. This production rate can be calculated by dividing new reserve additions by the applicable reserves/production ratio. A second method of estimating new gas production is to relate historical average new gas well production to new gas well drilling.

New Gas Reserve Additions

The drilling projections outlined in Chapter One were used to estimate future activity levels. Gas finding rates consistent with experience were assumed as outlined in the 1972 NPC report, *U.S. Energy Outlook*. Table 41 shows recent history and summarizes new gas reserve additions through 1976. Domestic gas reserve additions are projected to average 11.9 TCF annually in the 1974-1976 period --up sharply from the depressed level of 6.9 TCF of 1973. (Regional data shown in Appendix H, Table 92.)

TABLE 41

U.S. NATURAL GAS RESERVES AND PRODUCTION (EXCLUDES NORTH SLOPE)—1970-1976

(Trillion Cubic Feet)

Historical	Reserves First of Year (TCF)	Less Production (TCF)	Plus Added Reserves (TCF)	Reserves End-of-Year (TCF)	Ratio Gas Reserves to Production
1970	271.6	22.0	11.2	260.8	11.9
1971	260.8	22.1	9.8	248.5	11.3
1972	248.5	22.5	9.6	235.6	10.5
1973	235.6	22.6	6.9	219.9	9.7
Projected					
1974	219.9	22.4	11.9	209.4	9.4
1975	209.4	21.8	11.9	199.5	9.2
1976	199.5	21.0	11.9	190.4	9.1

Reserve/Production Ratios

The NPC *U.S. Energy Outlook* report was also used as a guide for determining domestic R/P ratios (regional data shown in Appendix H, Table 93). As shown in Table 41, a composite domestic R/P ratio of 9.1 was calculated for 1976, compared to 10.5 in 1972. A declining R/P ratio indicates that reserves are being produced at a faster rate than they are being discovered.

New Gas Production by R/P Relationships

New gas production was determined by dividing the projected reserve additions by the R/P ratios shown in Table 41 (Appendix H, Table 96 shows the projection by regions for both associated and non-associated volumes). The projection indicates that new gas production will average some 3.6 BCF/D in the 1974-1976 period or 1.3 TCF. Historical and projected total gas production and estimated total gas reserves remaining at year-end are shown by regions in Appendix H, Tables 94 through 95.

New Gas Production by Gas Well Drilling Estimates

A second method of calculating new gas production is to relate average gas well production to new gas well drilling. By multiplying the gas well production of 185 MMCF/YR (recent history as shown in Appendix H, Table 97) to the projection of new gas completions as shown in Appendix D (Table 54), total new gas production was calculated. Table 42 shows results of this analysis. It likewise indicates an average new gas production of 1.3 TCF produced annually during the 1974-1976 period.

TABLE 42

U.S. GAS PRODUCTION FROM NEW WELLS

Historical	New Gas Wells	Average Well Production MMCF/YR	Total Gas Production From New Wells TCF/YR
1970	3,840	186.9	0.7177
1971	3,830	183.6	0.7032
1972	4,928	185.8	0.9119
1973	6,362	183.7	1.1687
Projected			
1974	6,935	185.0	1.283
1975	6,957	185.0	1.287
1976	7,000	185.0	1.295

Not all new gas production will require new processing facilities because a growing portion of non-associated gas is dry, and spare capacity at existing plants is increasing. The amount of new gas plant processing capacity has been cyclical, shown in Table 43. For example, the amount of new gas processing capacity averaged 209 percent of new gas production in 1970 and only 52.3 percent in 1972. Because most existing gas streams are now being processed, new gas processing capacity will follow the new gas production curve. The amount of new gas processed is expected to average only about 50 percent of new gas production in 1976.

TABLE 43

U.S. GAS PRODUCTION *VERSUS* GAS PROCESSED

Historical	New Gas Production (BCF)	(MMCF/D)	Percent New Capacity Required	New Gas Processed (MMCF/D)
1970	960	2,630	209.0	5,498
1971	983	2,693	77.4	2,085
1972	1,028	2,816	52.3	1,473
1973	981	2,687	129.7	3,484
Projected				
1974	1,308	3,584	60.4	2,165
1975	1,324	3,627	54.9	1,990
1976	1,339	3,668	49.8	1,828

New Gas Processing Plants

The size and location of new gas processing plants were estimated by examining recent construction trends, construction announcements in trade publications and amount of new gas available. A summary of the projected plant construction is shown in Table 44. Regional detail is shown in Appendix H, Table 98.

TABLE 44

PROJECTED ANNUAL NEW PLANT CONSTRUCTION IN THE UNITED STATES—1974-1976

(Million Cubic Feet Per Day)

Number of Plants	Average Size of Plants (MMCFD)	Total Capacity (MMCFD)
11	10	110
7	20	140
4	30	120
4	40	160
4	60	240
3	100	300
33	32.4	1,070

The recent trend to much smaller gas processing plants is expected to continue. Almost 80 percent of all projected new plants will be less than 40 MMCF/D. Average new plant size is only 32.4 MMCF/D compared to an average of almost 100 MMCF/D for all existing plants. No large plants are expected during the three-year period because of the required 2 to 3-year construction time.

New Plant construction is expected to account for slightly more than one-half of new capacity added during the 1974-1976 period. This is the same pattern that prevailed in the 1970-1973 period.

Expansions to Existing Plants

Expansions at existing plants were derived by subtracting out the new plant capacity estimate from the amount of new gas projected to be processed. A summary of new plant capacity *versus* expansions to existing plants is shown in Table 45.

TABLE 45

PROJECTED U.S. GAS PROCESSING PLANT CONSTRUCTION
(Million Cubic Feet Per Day)

	1974	1975	1976	Total 1974-1976
New Plants	1,070	1,070	1,070	3,210
Expansions	1,095	920	758	2,773
Total	**2,165**	**1,990**	**1,828**	**5,983**

Materials Consumption

New Gas Gathering Systems

The amount of steel pipe needed to extend gathering systems was estimated by examining recent industry experience. It is estimated that 100 tons of steel are required to extend gathering systems for each additional million cubic feet per day of gas. This factor was applied to new gas production in all regions except Alaska and Offshore Louisiana. Any new gas developed in Alaska in this time frame will probably be handled by oil production facilities then injected into the producing zone. Offshore Louisiana gas gathering systems will be extended by gas pipeline companies and will not be a requirement of gas processing companies. Steel pipe requirements rise slowly from 226 thousand tons in 1974 to 235 thousand tons in 1976 (shown in Table 46 by regions in Appendix H, Table 98).

New Plants

Recent construction trends indicate that new plants are predominately cryogenic, turboexpander, skid-mounted plants, located near the producing fields. Total materials needed for new plant construction will average about 6.9 thousand tons annually and compression for gathering systems will add another 3.7 thousand tons. Carbon steel is the primary material in new plants, accounting for 86 percent of the 6.9 thousand tons.

Expansions

Expansions to existing plants will require less material than new plant construction during the 1974-1976 period. The peak construction year of 1974 require 8.1 thousand tons of material and declines to 5.6 thousand tons in 1976.

Maintenance

Materials required to replace equipment at existing plants will become much larger than historical because of the increasing average age of plants and the preventive maintenance required to minimize down-time at plants. Materials consumed in maintenance of existing facilities will total 14.5 thousand tons of material in 1974, equal to about three-fourths of materials consumed in the construction of new plants and expansions to existing plants. Consumption of maintenance materials is projected to decline in 1975 and 1976 because of lower gas throughput at existing plants.

Materials Summary

A summary of carbon steel required by categories is shown in Table 46. Projected carbon steel requirements total 254.4 thousand tons in 1974 and rise to nearly 260 thousand tons in 1976. Gathering systems will require almost 90 percent of the total.

TABLE 46
ESTIMATED CARBON STEEL REQUIREMENTS
(Tons)

	1974	1975	1976
New Plants	5,791.2	5,971.2	5,971.2
Expansions	4,433.0	3,734.3	3,075.3
Maintenance	7,992.4	7,492.2	7,088.4
Compressors	10,462.9	9,832.0	9,164.1
Gathering Systems	225,831.0	230,838.0	234,805.0
Total	**254,510.5**	**257,787.7**	**259,934.0**

Chemicals Consumption

Operation of a gas processing plant requires a wide variety of chemicals for gas and water treating. Consumption will vary according to the type of gas being processed. Average consumption rates (pounds per million cubic feet of gas processed) were developed for the most significant chemicals. The chemical requirements are expected to decline during the three-year period because of projected lower gas throughput. Consumption of chemicals by the gas processing industry will remain large, however, totaling 140.8 thousand tons in 1976. Details are shown in Table 47.

TABLE 47

CHEMICALS CONSUMPTION AT ALL GAS PROCESSING PLANTS

	Unit Consumption (Pounds Per Million Cubic Feet)	Estimated For All Gas Processed (Tons) 1974	1975	1976
Gas Treating:				
Ethylene Glycol	1.5	14,217	13,332	12,291
Diethylene Glycol	0.1	948	889	819
Triethylene Glycol	1.0	9,478	8,888	8,194
Mono-Ethanol Amine	1.5	14,217	13,332	12,291
Di-Ethanol Amine	0.4	3,791	3,555	3,278
Sulfanol	0.1	948	889	819
Dehydration Dessicants	0.2	1,896	1,778	1,639
Catalyst, Sulfur Plants	0.4	3,791	3,555	3,278
Liquids Treating:				
Caustic Soda	1.0	9,478	8,888	8,194
Perco Reagent	0.05	474	444	410
Other Products	0.5	4,739	4,444	4,097
Water Treating:				
Chlorine	0.013	123	116	107
Soda Ash	0.006	57	53	49
Sulfuric Acid (66° Baume')	2.5	23,695	22,219	20,485
Commercial Compounds	1.1	10,426	9,777	9,013
Antifreeze	1.0	9,478	8,888	8,194
Miscellaneous:				
Ethyl Mercaptans	0.065	616	578	533
Mercury	0.008	76	71	66
Methanol	5.75	54,499	51,105	47,116

Chapter Seven

DRILLING AND PRODUCTION TRANSPORTATION AND FUELS

INTRODUCTION

It is common industry practice for the same transportation equipment and fuels to be used concurrently to serve exploration, drilling and production operations. Transportation and fuels availability are therefore discussed in this separate chapter rather than in Chapter Three (Drilling) and Chapter Four (Production).

DEFINITION

Equipment: *The equipment discussed in this chapter is required by operators (including contractors) for the movement of men, materials and machinery in the conduct of oil and gas operation. This includes on- and offshore exploration and drilling but excludes well servicing. Also discussed are the fuels required to power mobile and stationary engines used in such service.*

FINDINGS AND CONCLUSIONS

No major constraints on drilling and producing activity are anticipated relative to the availability of basic transportation equipment, vehicles, boats and aircraft, and fuels for drilling rigs and transportation. While the industry had not been impaired to any great extent up to mid-year 1974, increasing lead time for replacement of equipment, unavailability of spare parts, fuel shortages and higher fuel costs could be problems in 1975 and 1976. These could affect the efficient geographical location of transportation equipment and result in delayed movement between locations.

DISCUSSION

Land Vehicles

Many oilfield carriers have diverted their efforts from strict oilfield service in favor of over-the-road transportation because the latter is more attractive from the standpoint of revenue. Also, field work--the dismantling, transporting and erecting of oilfield drilling rigs and other equipment used in exploring and producing gas and petroleum--is a specialized service; it is performed in out-of-the-way places, in all kinds of weather, and it is a 24-hour, every day task which is not attractive to carriers' employees.

For moving the drilling rigs, there are adequate vehicles available and they will be available for the next 2 years--provided monetary rates are raised to attract them to this service.

Some of the problems which may be encountered are as follows:

- Increasing the current lead time on delivery of basic equipment for truck tractors (10-month delivery) and truck trailors (10-15 month delivery).
- Increasing the current lead time on delivery of certain replacement parts.
- Increasing preference of carriers for more lucrative over-the-road contracts.
- Availability of fuels. (95 percent of the demand is diesel, 5 percent gasoline.)

Boats

Early in 1974, 355 boats were operating with 115 additional units under construction (Table 48). These should be adequate to meet foreseeable 1974-1976 needs for drilling and production activities, although fuel availability is a possible problem.

Aircraft

The helicopter is the basic aircraft used by the industry in drilling and production operations. Availability of these craft is shown in Table 49. No major constraints on drilling and producing activity are anticipated relative to the availability of this equipment. Currently, delivery on a small helicopter is 6 months, and delivery on a medium helicopter is 1 year.

There are several potential problems in the utilization of helicopters:

- Fuel availability
- Increasing delivery time on parts
- Range limitation as activity moves further offshore.

Fuel

Fuel availability is not currently a constraining factor on drilling or production operations. With the present Federal Energy Administration (FEA) 100 percent allocation of various fuels to the oil industry, any possible future constraints should be eliminated.

Fuel requirements were evaluated by five categories: (1) drilling rigs, (2) helicopters, (3) boats, (4) trucks (for hire), and (5) trucking (service company and drilling contractors). Detailed data for these categories appears in Appendix I (Tables 99-106).

TABLE 48

DISTRIBUTION OF BOATS OPERATING OR UNDER CONSTRUCTION

Operating

Alaska/Bering Sea

Tugs	10
Supply	2
Crewboats	2
Total	**14**

Atlantic Coast—U.S.

Tugs	2
Total	**2**

Gulf of Mexico

Tug/Supply	1
Tugs	33
Ocean Tugs	8
Crewboats	90
Supply	30
Utility	31
Survey	1
Stand-by	1
Total	**195**

Pacific Coast—U.S.

Tugs	32
Supply	2
Total	**34**

U.S. Shipyards

Supply	4
Crewboats	7
Total	**11**

U.S. (Unspecified)

Tugs	11
Utility	14
Survey	49
Crewboats	16
Total	**90**

Bahamas

Crewboats	2
Tugs	4
Total	**6**

Caribbean

Crewboats	1
Supply	2
Total	**3**

Grand Total Operating 355

Under Construction

Acadian Marine Services, Inc.
(New Orleans, La.)

Tug/Supply	3
Total	**3**

Black & Gold Marine, Inc.
(New Orleans, La.)

Crewboats	3
Total	**3**

Bollinger & Boyd Barge Service
(Lockport, La.)

Tugs	1
Supply	1
Total	**2**

Otto Candies, Inc.
(Des Allemands, La.)

Tugs	8
Total	**8**

Arthur Levy Boat Services
(Morgan City, La.)

Tug/Supply	8
Total	**8**

Offshore Fleet, Inc.
(Marrero, La.)

Cargo vessels	3
Total	**3**

Offshore Logistics, Inc.
(Lafayette, La.)

Crewboats	5
Supply	1
Tug/Supply	5
Total	**11**

Robin Boat Rental Service, Inc.
(Harvey, La.)

Tugs	4
Total	**4**

TABLE 48 (continued)

Coastal Marine, Inc.	
(Morgan City, La.)	
Crewboats	2
Total	**2**
D & B Boat Rentals	
(New Iberia, La.)	
Supply	1
Total	**1**
Dearborn Marine Service Corp.	
(Freeport, Texas)	
Tug/Supply	4
Utility	1
Total	5
Foss Launch & Tug Co.	
(Seattle, Wash.)	
Tugs	2
Total	**2**
Galaxie Marine	
(Patterson, La.)	
Utility	1
Total	**1**
Guzzetta Offshore Marine Service	
(Berwick, La.)	
Supply	1
Total	**1**
Jackson Marine Corp.	
(Arkansas Pass, Tx.)	
Supply	3
Tugs	4
Utility	2
Total	**9**
Sealcraft Operators	
(Galveston, Tx.)	
Tug/Supply	1
Total	**1**
State Boat Corp.	
(Houston, Tx.)	
Tug/Supply	1
Supply	1
Total	**2**
Stewart & Stevenson Services Inc.	
(Houston, Tx.)	
Supply	1
Tug/Supply	6
Total	**7**
Tidewater Marine Service, Inc.	
(Morgan City, La.)	
Supply	6
Tug/Supply	11
Crewboats	1
Tugs	3
Total	**21**
Zapata Marine Services	
(Houston, Tx.)	
Tug/Supply	8
Total	**8**
Unnamed Company	
Tugs	13
Total	**13**

Grand Total Under Construction 115

Source: *Offshore Magazine*, Vol. 34, No. 3, March 1974.

TABLE 49

AVAILABILITY OF HELICOPTERS BY TYPE

1974	60 medium helicopters (8-14 seat) 335 small helicopters (90 percent turbine)
1975	70 medium helicopters 390 small helicopters
1976	75 medium helicopters 400 small helicopters

75 percent helicopters work production
25 percent helicopters work drilling operations

Sources: Petroleum Helicopters, Inc., New Orleans, Louisiana.
Rowan Drilling Company, Houston, Texas.

APPENDICES

APPENDIX A

Request Letters

United States Department of the Interior

OFFICE OF THE SECRETARY
WASHINGTON, D.C. 20240

DEC 5 - 1972

Dear Mr. True:

The United States is in a period of rapidly increasing dependence on imported petroleum. Associated with this dependency is the high risk involved to the Nation's economic well-being and security in the event these needed, imported energy supplies are interrupted for any reason. With such an alarming trend it becomes mandatory that the Nation's emergency preparedness program to insure supply of petroleum be improved without delay.

Over the past years, the Council has provided the Department of Interior with many outstanding studies which have contributed directly to preparedness for a national emergency. The Council's recent comprehensive energy outlook study indicates national policy options which will minimize dependence on imported petroleum over the long term. However, the study does not examine and evaluate alternatives, possible emergency actions and the results of such actions in the event of a temporary denial or marked reduction in the volume of imported petroleum available to the Nation during the next few years ahead.

The Council is therefore requested to make a comprehensive study and analysis of possible emergency supplements to or alternatives for imported oil, natural gas liquids and products in the event of interruptions to current levels of imports of these energy supplies. Where possible, the results of emergency measures or actions that could be taken before or during an emergency under present conditions should be quantified. For the purpose of this study only, assume that current levels of petroleum imports to the United States are reduced by denial of (a) 1.5 million barrels per day for a 60-day period, and (b) 2.0 million barrels per day for a 90-day period.

Of particular interest are supplements to normal domestic supply such as: the capability for emergency increases in production, processing, transportation and related storage; the ability to provide and maintain an emergency storage capability and inventories; interfuel substitution or convertibility of primary fuels in the major fuel consuming sectors; side effects of abnormal emergency operations; gains in supply from varying levels of curtailments, rationing and conservation measures; gains from temporary relaxation of environmental restrictions; as well as the constraints, if any, imposed by deficient support capability if an extraordinary demand occurs for manpower, materials, associated capital requirements and operating expenses due to emergency measures.

Such studies should be completed as soon as practicable, with at least a preliminary report presented to me by July 1973.

Sincerely yours,

Hollis M. Dole

Hollis M. Dole

Assistant Secretary of the Interior

Mr. H. A. True, Jr.
Chairman
National Petroleum Council
1625 K Street, N. W.
Washington, D. C. 20006

United States Department of the Interior

OFFICE OF THE SECRETARY
WASHINGTON, D.C. 20240

DEC 21 1973

Dear Mr. True:

The present energy situation makes it imperative that increased domestic exploration for energy sources, particularly oil, be undertaken at the earliest possible time.

So that a rational program might be developed the Department of the Interior has an urgent need to know the availability of materials, manpower and equipment necessary for the exploration, drilling and production of oil during the next two years. Any shortages of materials, manpower or equipment needed for these tasks should indicate the probable limitation on drilling activity. The duration and causes of such shortages, together with any possible measures to alleviate them, should be set forth.

At our request the National Petroleum Council's Committee on Emergency Preparedness is presently conducting a study to examine and evaluate alternatives, possible emergency actions and the results of such actions in the event of a temporary denial or marked reduction in the volume of imported petroleum available to the Nation.

In our letter to you of December 5, 1972, requesting the National Petroleum Council to undertake the above study one of the items mentioned was the capability for emergency increases in production. Because the information needed on the availability of materials, manpower and equipment for exploration and production falls within this category I am requesting that you have the National Petroleum Council's Committee on Emergency Preparedness appoint an appropriate subcommittee to undertake this task.

Because of the urgency of this matter your early response and cooperation will be greatly appreciated.

Sincerely yours,

Stephen A. Wakefield

Stephen A. Wakefield
Assistant Secretary

CONSERVE AMERICA'S ENERGY

Mr. H. A. True, Jr.
Chairman
National Petroleum Council
c/o True Oil Company
Post Office Drawer 2360, Casper, Wyo. 82601

Save Energy and You Serve America!

APPENDIX B

Committee Rosters

The following industry representatives have participated in this study.

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APPENDIX C
Flow Diagrams

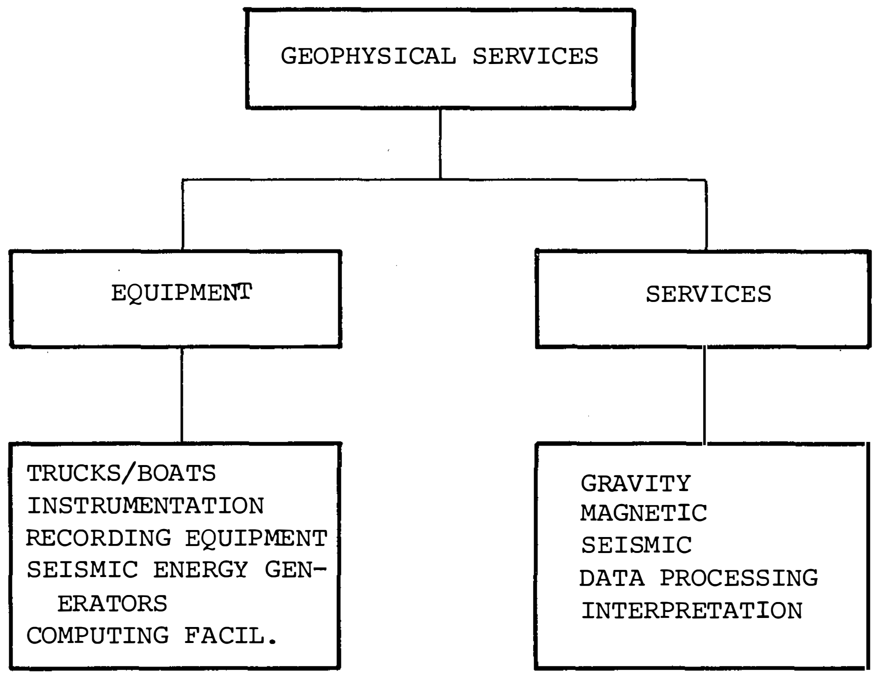


Figure 9. Chart A--Geophysical Services.

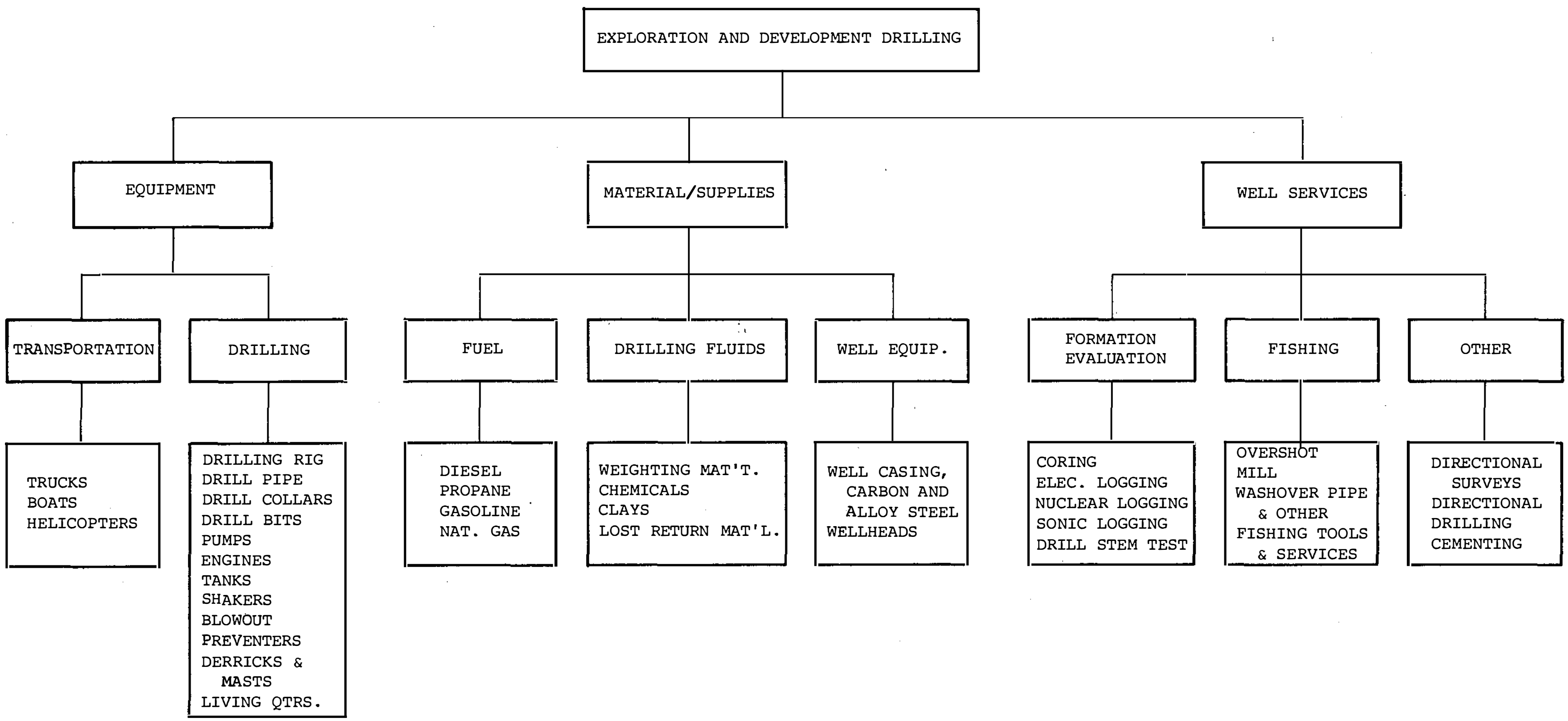


Figure 10. Chart B--Exploration and Development Drilling.

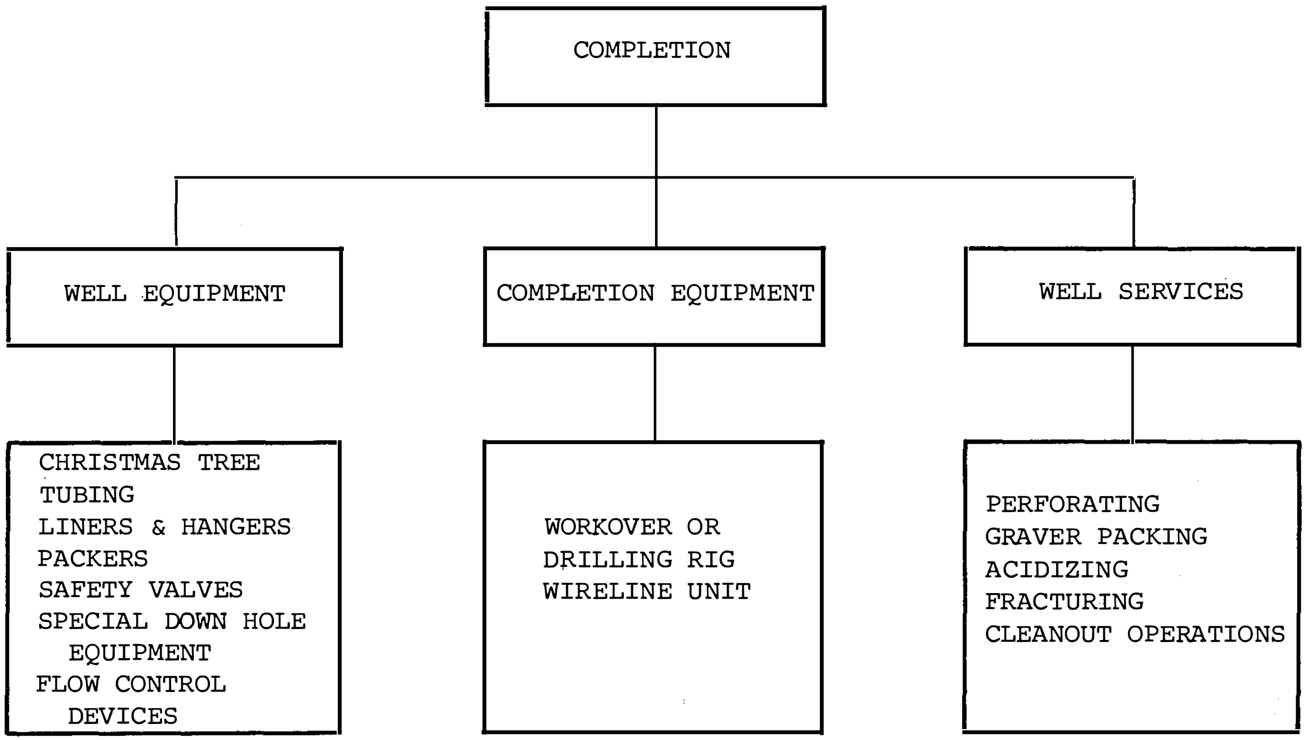


Figure 11. Chart C--Completion.

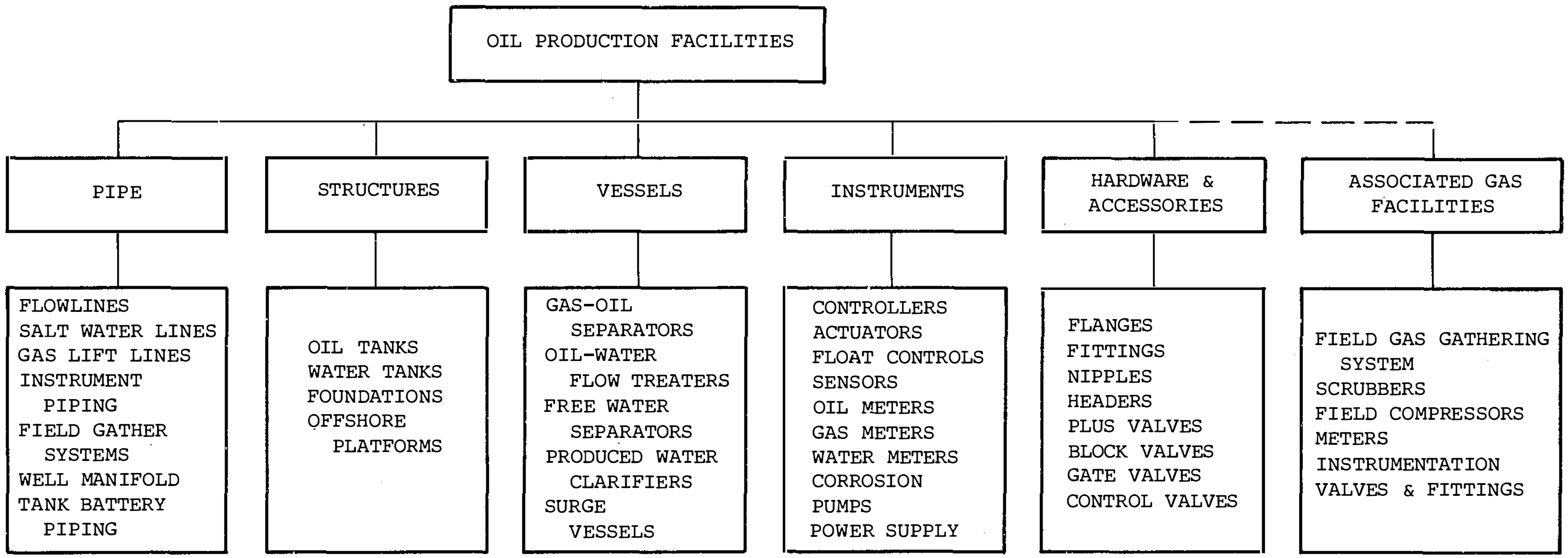


Figure 12. Chart D--Oil Production Facilities.

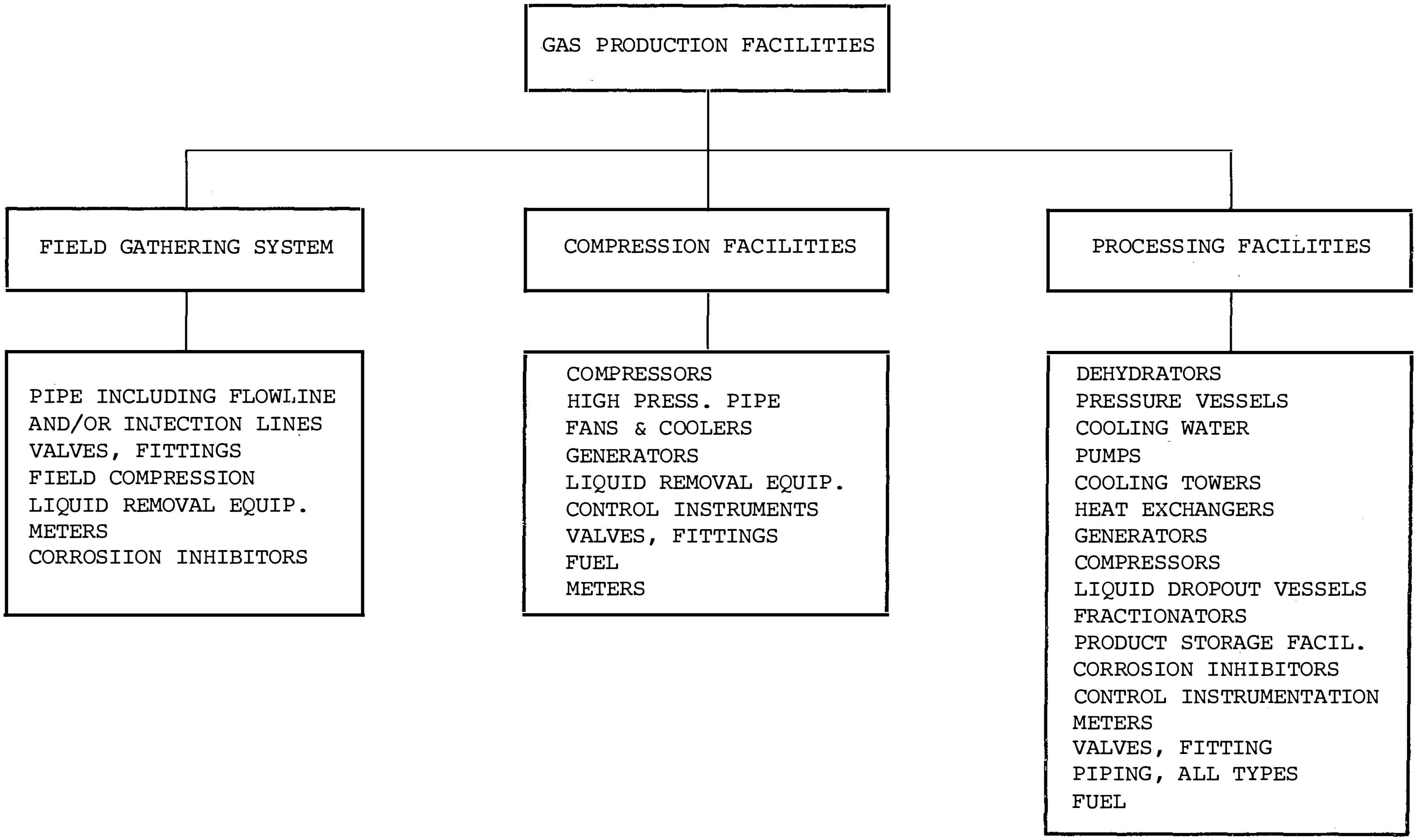


Figure 13. Chart E--Gas Production Facilities.

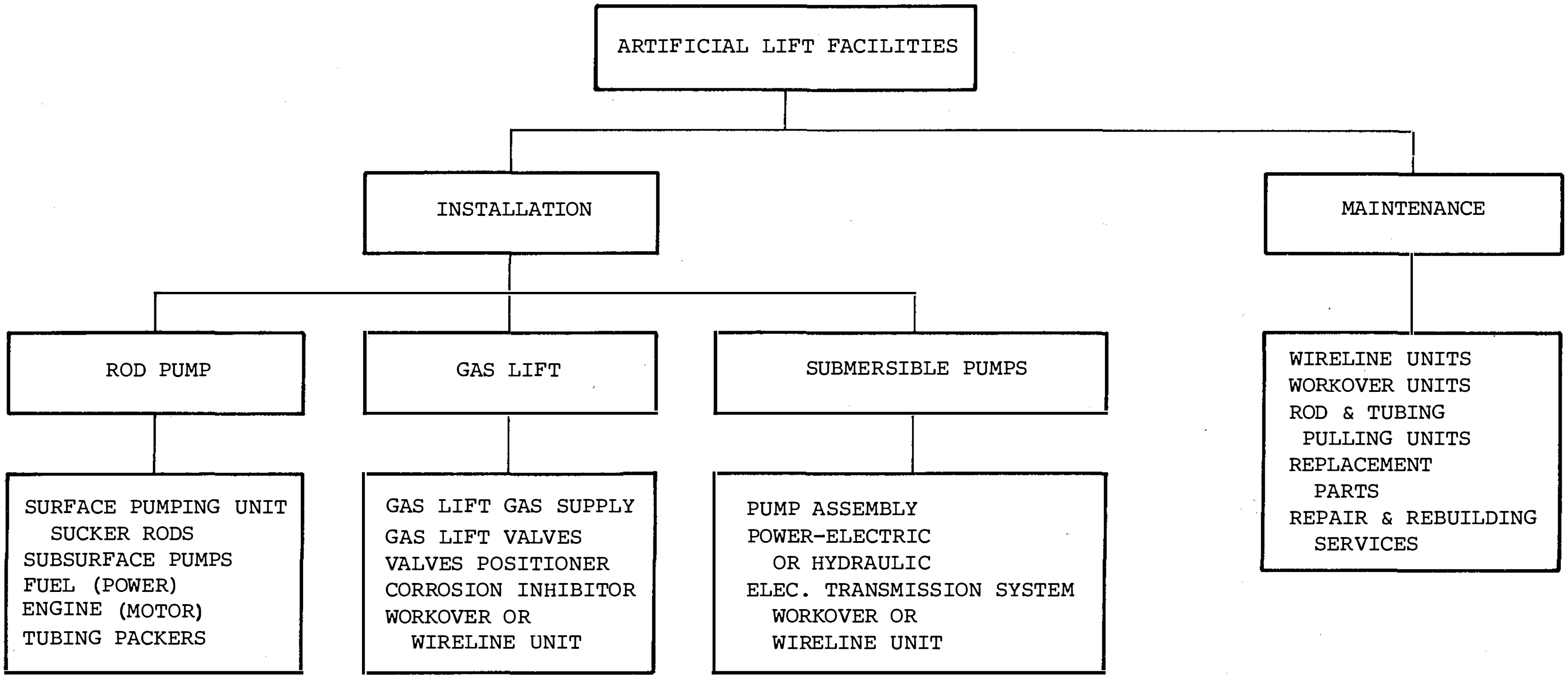


Figure 14. Chart F--Artificial Lift Facilities.

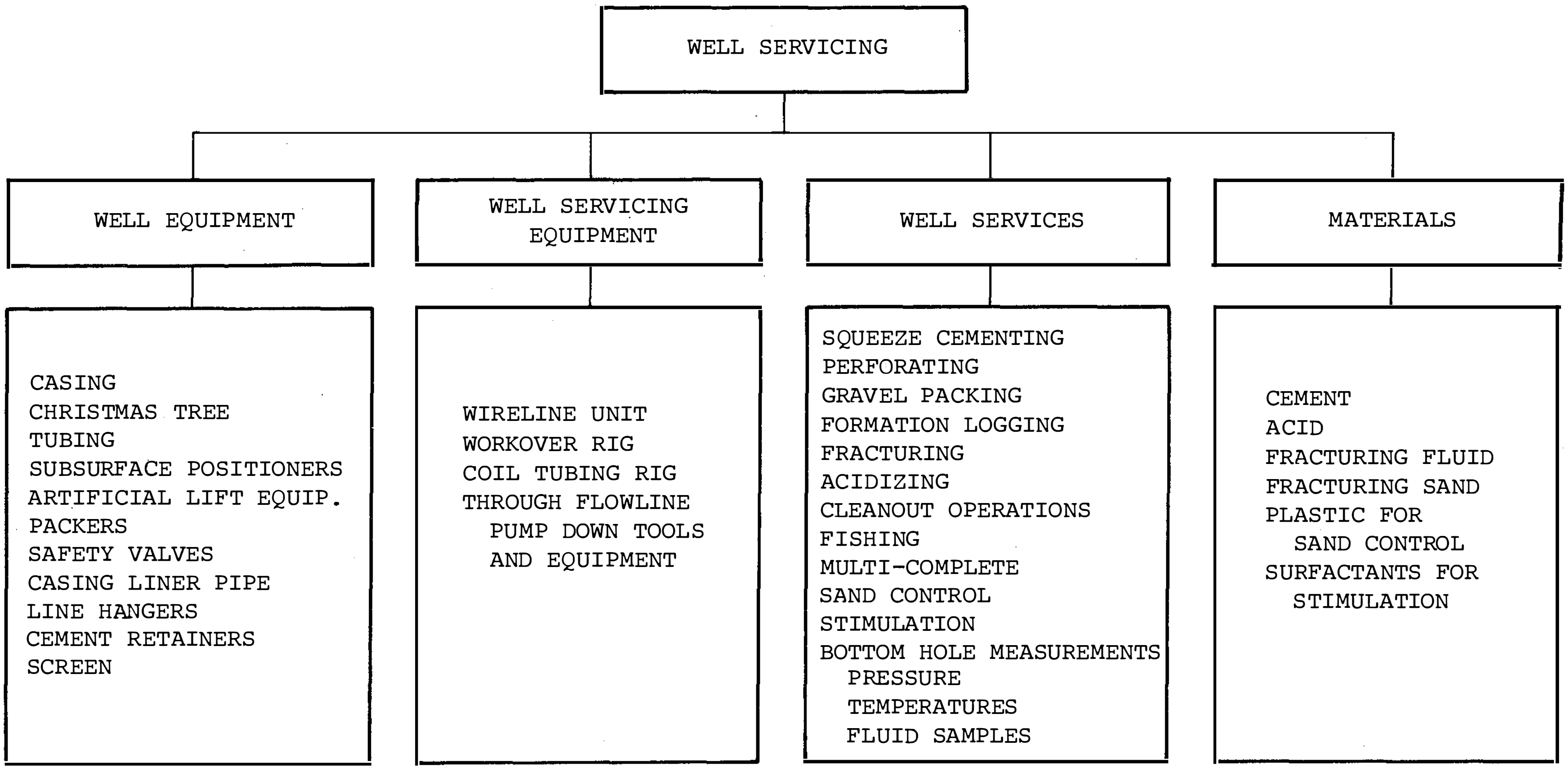


Figure 15. Chart G--Well Servicing.

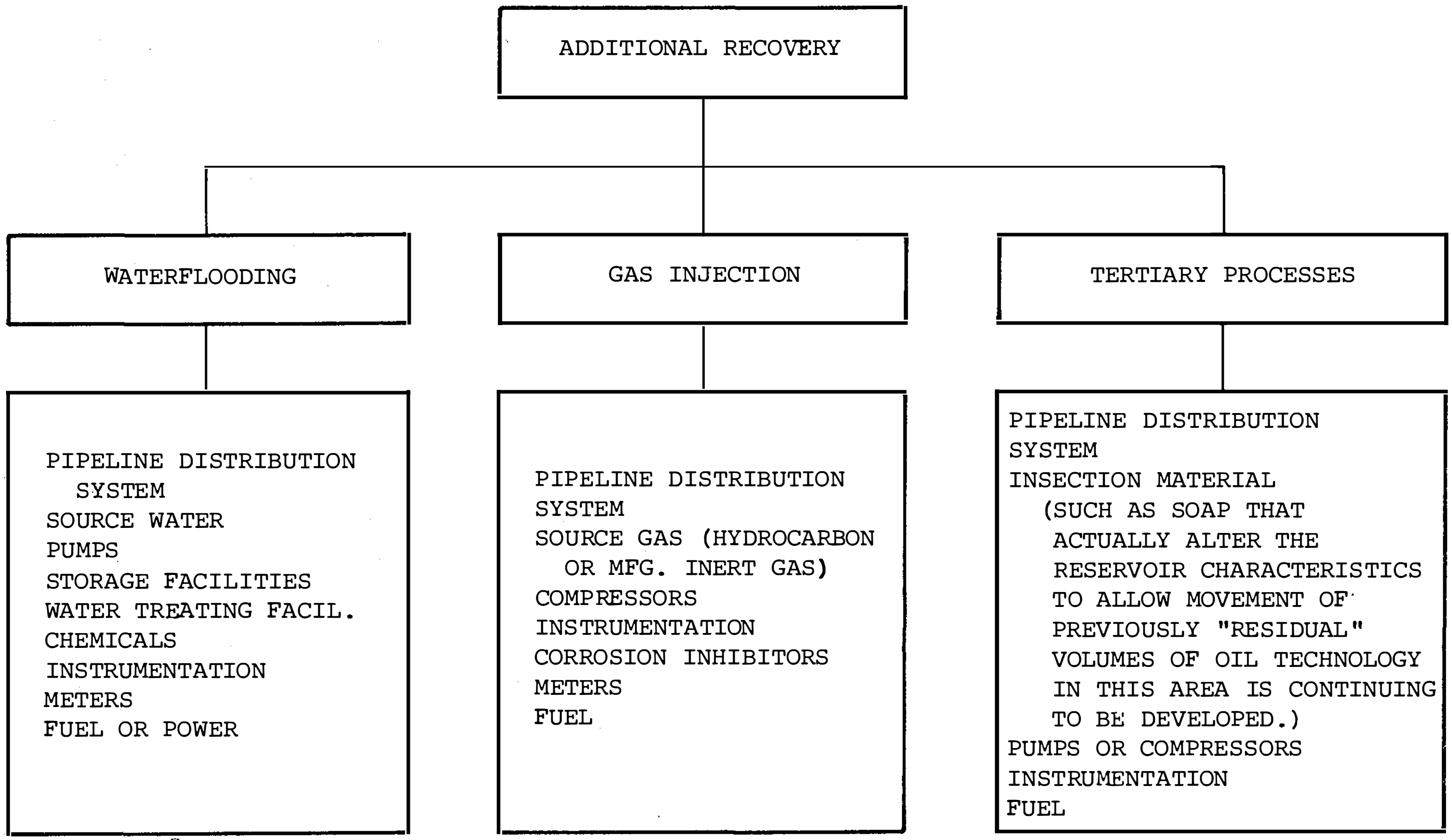


Figure 16. Chart H--Additional Recovery.

APPENDIX D
Outlook

TABLE 50

PROJECTED NEW WELLS TO BE DRILLED BY DEPTH INTERVAL

Depth (Thousand Feet)	Region 1 Alaska Onshore			Region 1A Alaska Offshore			Region 2 Pacific Coast Inland			Region 2A Pacific Coast Offshore		
	1974	1975	1976	1974	1975	1976	1974	1975	1976	1974	1975	1976
0-5	4	9	12	2	2	2	1,247	1,208	1,200	58	70	115
5-10	28	66	87	5	5	6	432	410	412	55	65	104
10-15	19	46	61	7	7	12	65	64	62	17	21	36
15+	4	11	14	1	1	2	8	10	11	–	–	–
Total	55	132	174	15	15	22	1,752	1,692	1,685	130	156	255

Depth (Thousand Feet)	Region 3 Rocky Mountain States			Region 4 Mid-Continent States			Region 5 W. Texas & E. New Mexico			Region 6 Tex. G.C., N. La., & S. Ark.		
	1974	1975	1976	1974	1975	1976	1974	1975	1976	1974	1975	1976
0- 5	2,117	2,192	2,275	5,514	5,313	5,087	2,834	2,836	2,838	2,092	2,033	1,990
5-10	1,766	1,708	1,637	1,577	1,581	1,588	2,462	2,451	2,557	1,737	1,662	1,594
10-15	208	220	234	329	332	337	297	299	306	387	395	404
15+	26	28	30	68	71	75	56	57	61	21	21	24
Total	4,117	4,148	4,176	7,488	7,297	7,087	5,649	5,643	5,762	4,237	4,111	4,012

Depth (Thousand Feet)	Region 6A Gulf Coast Offshore			Region 7 Southeastern States			Region 8 Northeastern States			Total U.S.A.		
	1974	1975	1976	1974	1975	1976	1974	1975	1976	1974	1975	1976
0- 5	63	70	78	156	164	169	5,643	5,717	5,793	19,730	19,614	19,560
5-10	538	606	678	621	643	680	1,687	1,670	1,670	10,908	10,867	11,016
10-15	491	553	617	694	719	758	4	4	4	2,518	2,660	2,829
15+	80	90	101	247	270	297	–	–	–	511	559	613
Total	1,172	1,319	1,474	1,718	1,796	1,904	7,334	7,391	7,467	33,667	33,700	34,018

TABLE 51

PROJECTED NEW FOOTAGE TO BE DRILLED BY DEPTH INTERVAL

Depth (Thousand Feet)	Region 1 Alaska Onshore			Region 1A Alaska Offshore			Region 2 Pacific Coast Inland			Region 2A Pacific Coast Offshore		
	1974	1975	1976	1974	1975	1976	1974	1975	1976	1974	1975	1976
0- 5	20	53	69	7	7	9	2,625	2,555	2,562	326	388	642
5-10	119	278	363	45	45	46	2,939	2,892	2,893	360	424	678
10-15	329	791	1,038	75	75	131	818	804	804	67	80	136
15+	82	198	260	22	22	33	112	125	134	–	–	–
Total	550	1,320	1,730	149	149	219	6,494	6,376	6,393	753	892	1,456

	Region 3 Rocky Mountain States			Region 4 Mid-Continent States			Region 5 W. Texas & E. New Mexico			Region 6 Tex. G.C., N. La., & S. Ark.		
	1974	1975	1976	1974	1975	1976	1974	1975	1976	1974	1975	1976
0- 5	6,971	7,570	7,533	16,448	16,231	15,784	8,502	8,603	8,711	3,664	3,623	3,582
5-10	12,950	12,735	12,611	11,315	11,205	11,181	17,293	17,514	17,990	13,859	13,639	13,473
10-15	2,565	2,666	2,814	3,795	3,833	3,885	3,611	3,591	3,620	4,412	4,424	4,444
15+	452	483	530	1,157	1,204	1,275	1,568	1,607	1,697	375	433	478
Total	22,938	23,454	23,488	32,715	32,473	32,125	30,974	31,315	32,018	22,310	22,119	21,977

	Region 6A Gulf Coast Offshore			Region 7 Southeastern States			Region 8 Northeastern States			Total U.S.A.		
	1974	1975	1976	1974	1975	1976	1974	1975	1976	1974	1975	1976
0- 5	272	297	327	476	477	479	14,178	14,274	14,394	53,489	54,078	54,092
5-10	5,219	5,780	6,447	5,175	5,284	5,590	9,412	9,320	9,300	78,686	79,116	80,572
10-15	5,969	6,641	7,404	8,362	8,699	9,037	42	42	41	30,045	31,646	33,354
15+	980	1,090	1,216	3,914	4,260	4,673	–	–	–	8,662	9,422	10,296
Total	12,440	13,808	15,394	17,927	18,720	19,779	23,632	23,636	23,735	170,882	174,262	178,314

TABLE 52

PROJECTED SUCCESSFUL NEW WELLS TO BE DRILLED BY DEPTH INTERVAL

Depth (Thousand Feet)	Region 1 Alaska Onshore			Region 1A Alaska Offshore			Region 2 Pacific Coast Inland			Region 2A Pacific Coast Offshore		
	1974	1975	1976	1974	1975	1976	1974	1975	1976	1974	1975	1976
0-5	3	6	9	1	1	1	1,060	1,030	1,020	44	53	86
5-10	22	53	70	3	3	3	268	265	266	41	49	78
10-15	15	37	49	4	4	7	39	38	37	9	11	18
15+	2	4	6	–	1	1	5	6	7	–	–	–
Total	42	100	134	8	9	12	1,372	1,339	1,330	94	113	182

	Region 3 Rocky Mountain States			Region 4 Mid-Continent States			Region 5 W. Texas & E. New Mexico			Region 6 Tex. G.C., N. La., & S. Ark.		
	1974	1975	1976	1974	1975	1976	1974	1975	1976	1974	1975	1976
0- 5	911	949	978	3,184	3,072	2,946	1,953	1,953	1,957	1,286	1,251	1,226
5-10	730	706	677	949	952	956	1,919	1,911	1,993	846	811	777
10-15	93	97	104	197	199	202	185	186	190	182	186	190
15+	13	14	15	41	43	45	40	41	44	5	6	7
Total	1,747	1,766	1,774	4,371	4,266	4,149	4,097	4,091	4,184	2,319	2,254	2,200

	Region 6A Gulf Coast Offshore			Region 7 Southeastern States			Region 8 Northeastern States			Total U.S.A.		
	1974	1975	1976	1974	1975	1976	1974	1975	1976	1974	1975	1976
0- 5	28	31	34	85	89	91	4,173	4,226	4,283	12,728	12,661	12,631
5-10	300	337	377	283	293	310	1,350	1,336	1,336	6,711	6,716	6,843
10-15	273	307	344	312	324	342	2	3	3	1,311	1,392	1,486
15+	42	47	53	121	132	146	–	–	–	269	294	324
Total	643	722	808	801	838	889	5,525	5,565	5,622	21,019	21,063	21,284

TABLE 53

PROJECTED SUCCESSFUL NEW FOOTAGE TO BE DRILLED BY DEPTH FOOTAGE

Depth (Thousand Feet)	Region 1 Alaska Onshore 1974	1975	1976	Region 1A Alaska Offshore 1974	1975	1976	Region 2 Pacific Coast Inland 1974	1975	1976	Region 2A Pacific Coast Offshore 1974	1975	1976
0- 5	15	40	52	4	4	5	2,179	2,122	2,129	245	270	482
5-10	95	222	290	27	27	27	1,772	1,748	1,752	270	318	509
10-15	263	633	830	38	38	66	409	402	402	34	40	68
15+	33	79	104	–	22	16	45	50	54	–	–	–
Total	406	974	1,276	69	91	114	4,405	4,322	4,337	549	628	1,059

Depth (Thousand Feet)	Region 3 Rocky Mountain States 1974	1975	1976	Region 4 Mid-Continent States 1974	1975	1976	Region 5 W. Texas & E. New Mexico 1974	1975	1976	Region 6 Tex. G.C., N. La., & S. Ark. 1974	1975	1976
0- 5	2,979	3,232	3,218	9,364	9,246	9,000	5,849	5,921	6,000	2,253	2,229	2,206
5-10	5,355	5,264	5,214	6,809	6,743	6,729	13,466	13,639	14,010	6,731	6,627	6,550
10-15	1,136	1,180	1,232	2,277	2,300	2,331	2,245	2,233	2,251	2,074	2,079	2,089
15+	226	243	265	694	722	765	1,129	1,157	1,222	105	121	133
Total	9,696	9,919	9,929	19,144	19,011	18,825	22,689	22,950	23,483	11,163	11,056	10,978

Depth (Thousand Feet)	Region 6A Gulf Coast Offshore 1974	1975	1976	Region 7 Southeastern States 1974	1975	1976	Region 8 Northeastern States 1974	1975	1976	Total U.S.A. 1974	1975	1976
0- 5	123	134	146	256	257	259	10,430	10,502	10,592	33,697	33,957	34,089
5-10	2,899	3,208	3,576	2,363	2,413	2,551	7,530	7,456	7,440	47,317	47,665	48,648
10-15	3,328	3,698	4,119	3,774	3,926	4,077	26	31	31	15,604	16,560	17,496
15+	510	567	627	1,918	2,087	2,290	–	–	–	4,660	5,048	5,476
Total	6,860	7,607	8,468	8,311	8,683	9,177	17,986	17,989	18,063	101,278	103,230	105,709

TABLE 54

PROJECTED SUCCESSFUL NEW WELLS TO BE DRILLED BY WELL TYPE—OIL, GAS AND SERVICE

	Region 1 Alaska Onshore			Region 1A Alaska Offshore			Region 2 Pacific Coast Inland			Region 2A Pacific Coast Offshore		
	1974	1975	1976	1974	1975	1976	1974	1975	1976	1974	1975	1976
Oil	38	90	121	7	8	11	1,171	1,140	1,131	80	89	150
Gas	4	10	13	1	1	1	75	73	72	–	10	17
Service	–	–	–	–	–	–	126	126	127	14	14	15
Total	**42**	**100**	**134**	**8**	**9**	**12**	**1,372**	**1,339**	**1,330**	**94**	**113**	**182**

	Region 3 Rocky Mountain States			Region 4 Mid-Continent States			Region 5 W. Texas & E. New Mexico			Region 6 Tex. G.C., N. La., & S. Ark.		
	1974	1975	1976	1974	1975	1976	1974	1975	1976	1974	1975	1976
Oil	1,104	1,116	1,121	2,694	2,625	2,548	3,125	3,120	3,194	1,264	1,227	1,196
Gas	594	601	604	1,450	1,414	1,372	551	550	564	954	926	903
Service	49	49	49	227	227	229	421	421	426	101	101	101
Total	**1,747**	**1,766**	**1,774**	**4,371**	**4,266**	**4,149**	**4,097**	**4,091**	**4,184**	**2,319**	**2,254**	**2,200**

	Region 6A Gulf Coast Offshore			Region 7 Southeastern States			Region 8 Northeastern States			Total U.S.A.		
	1974	1975	1976	1974	1975	1976	1974	1975	1976	1974	1975	1976
Oil	368	415	465	499	523	555	2,557	2,576	2,603	12,907	12,929	13,095
Gas	255	287	323	281	294	312	2,770	2,791	2,819	6,935	6,957	7,000
Service	20	20	20	21	21	22	198	198	200	1,177	1,177	1,189
Total	**643**	**722**	**808**	**801**	**838**	**889**	**5,525**	**5,565**	**5,622**	**21,019**	**21,063**	**21,284**

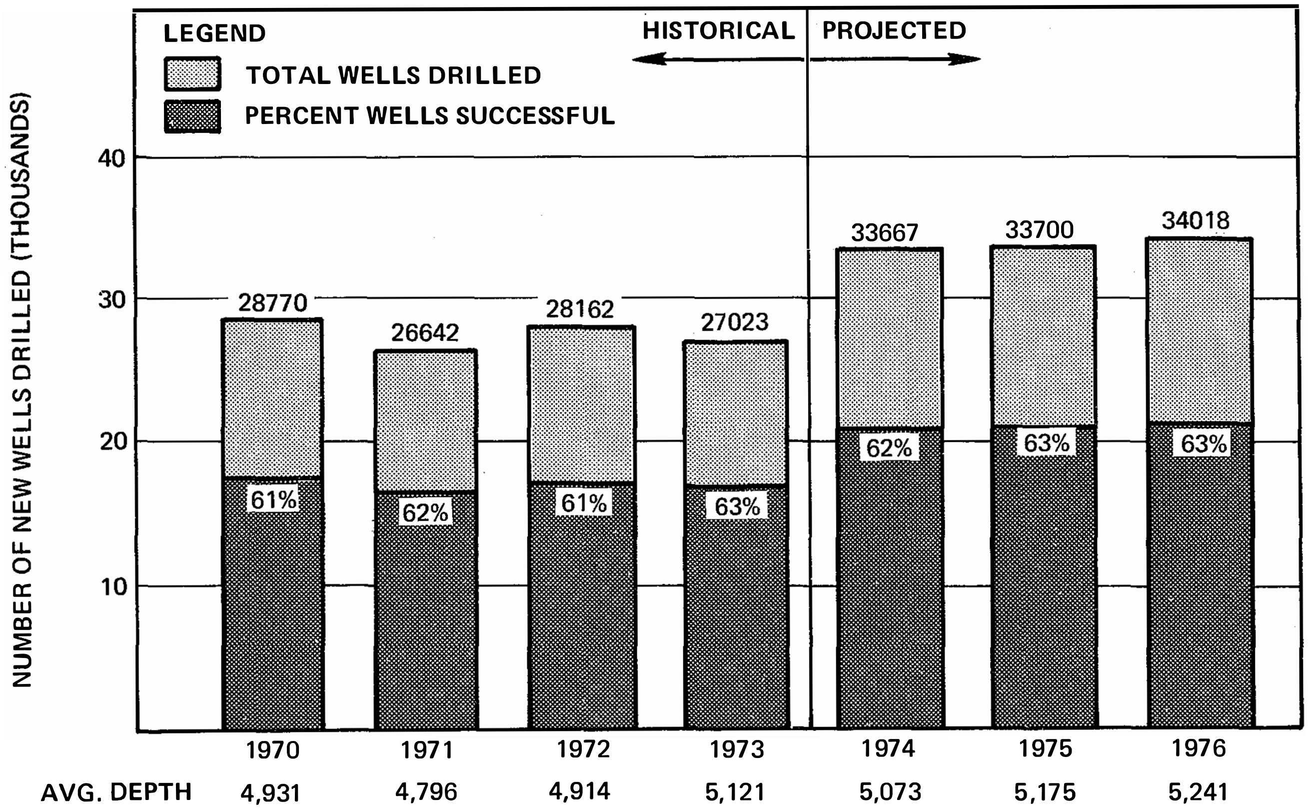


Figure 17. New Wells Drilled--Total U.S.A.

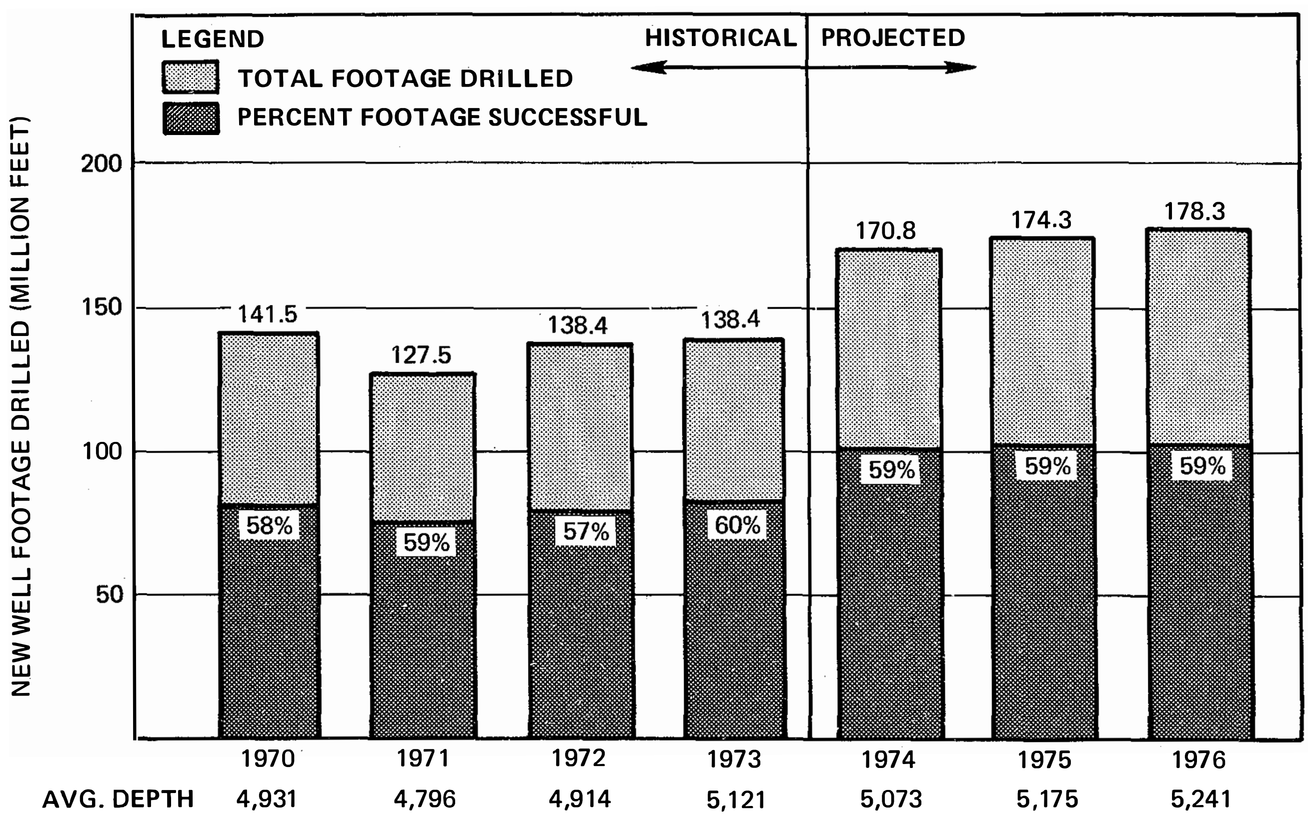


Figure 18. New Well Footage--Total U.S.A.

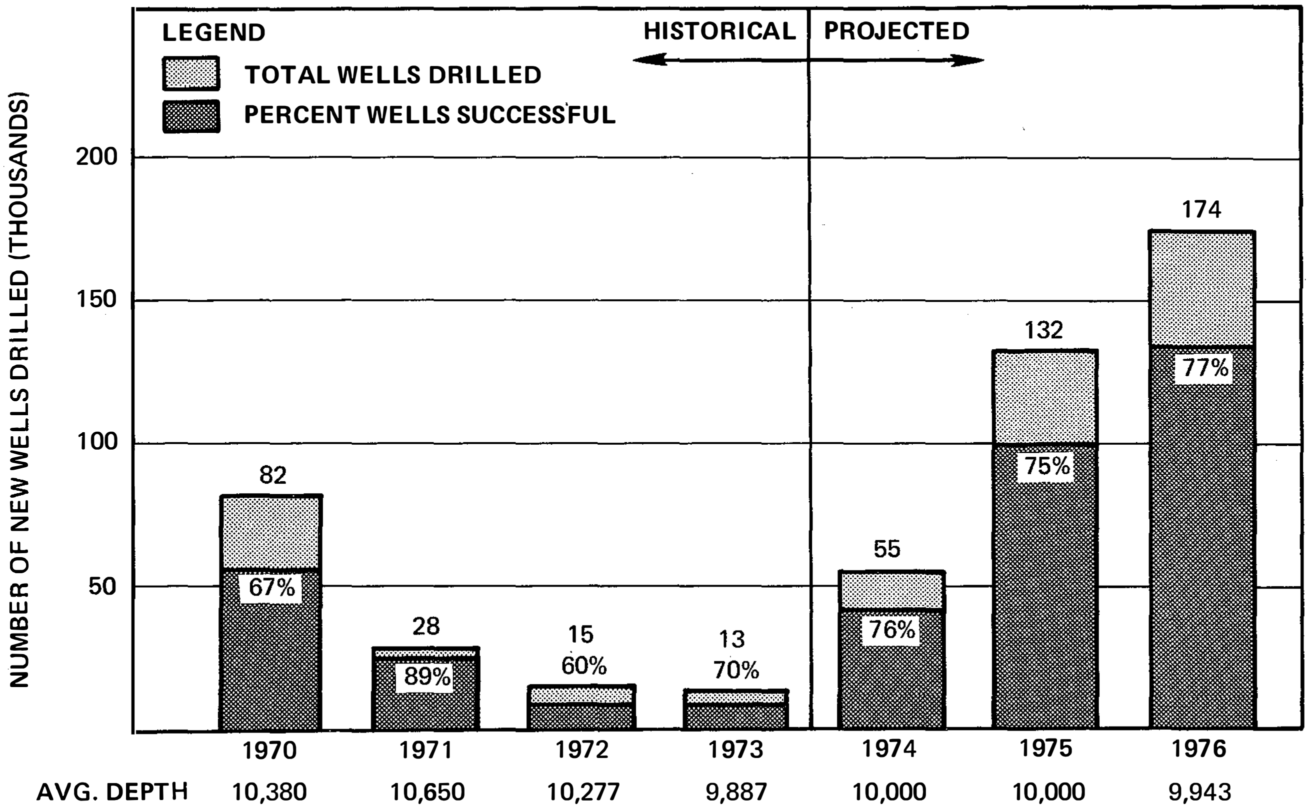


Figure 19. New Wells Drilled--Region No. 1.

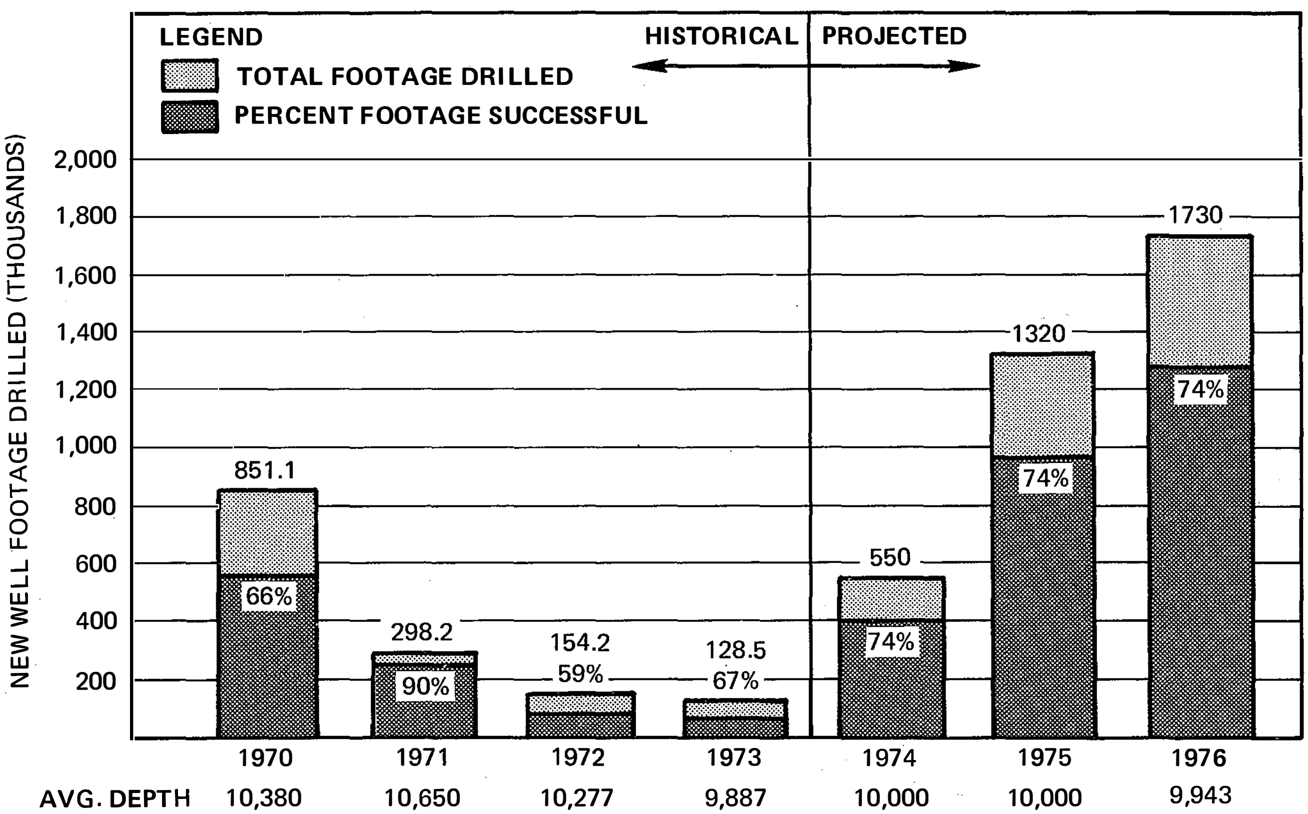


Figure 20. New Well Footage--Region No. 1.

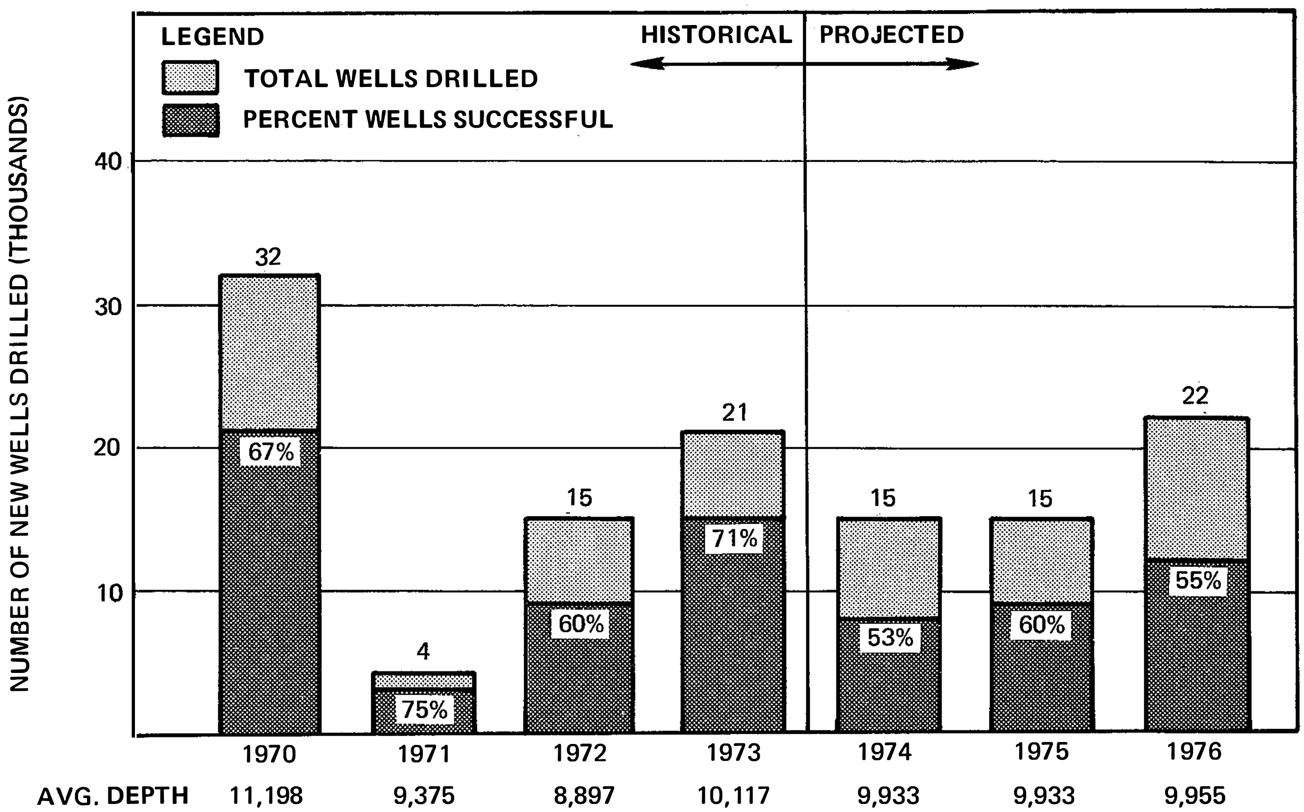


Figure 21. New Wells Drilled--Region No. 1-A.

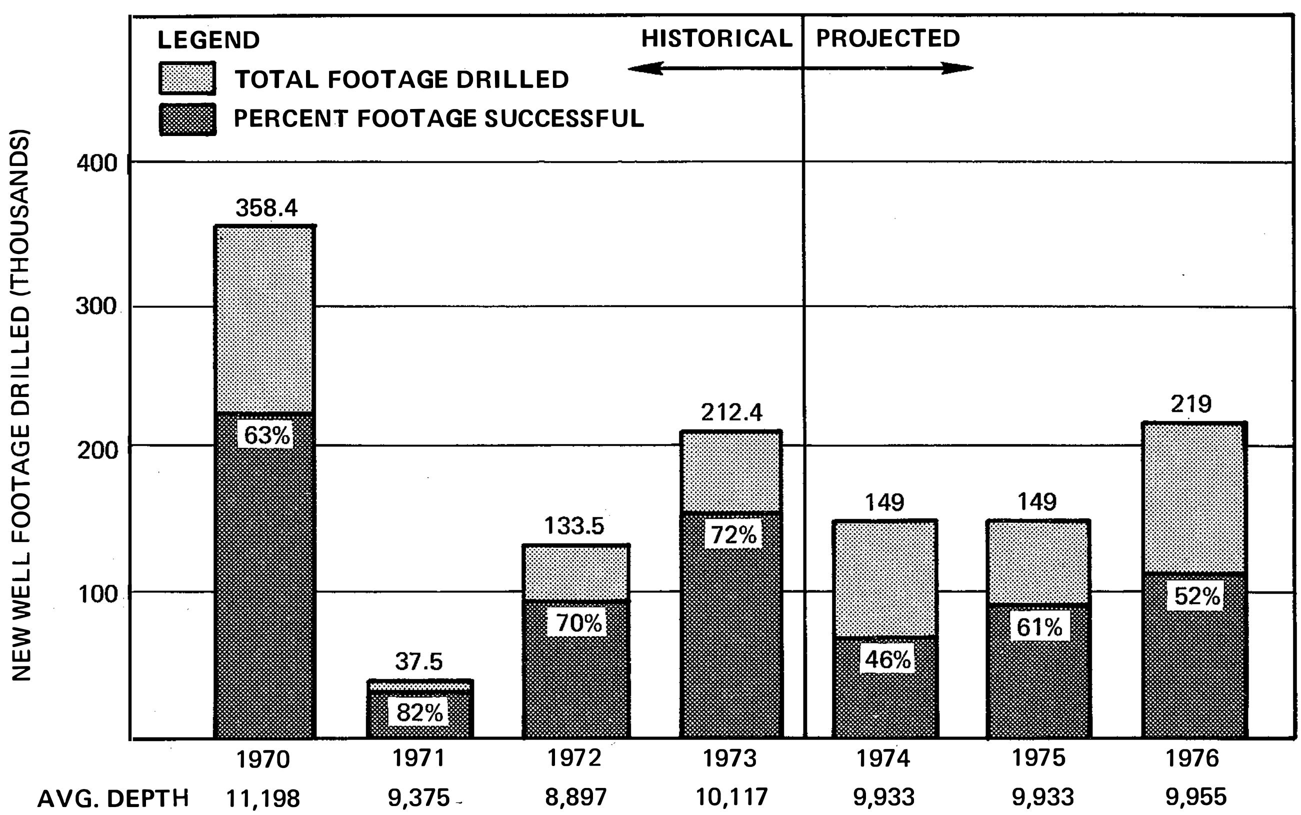


Figure 22. New Well Footage--Region No. 1-A.

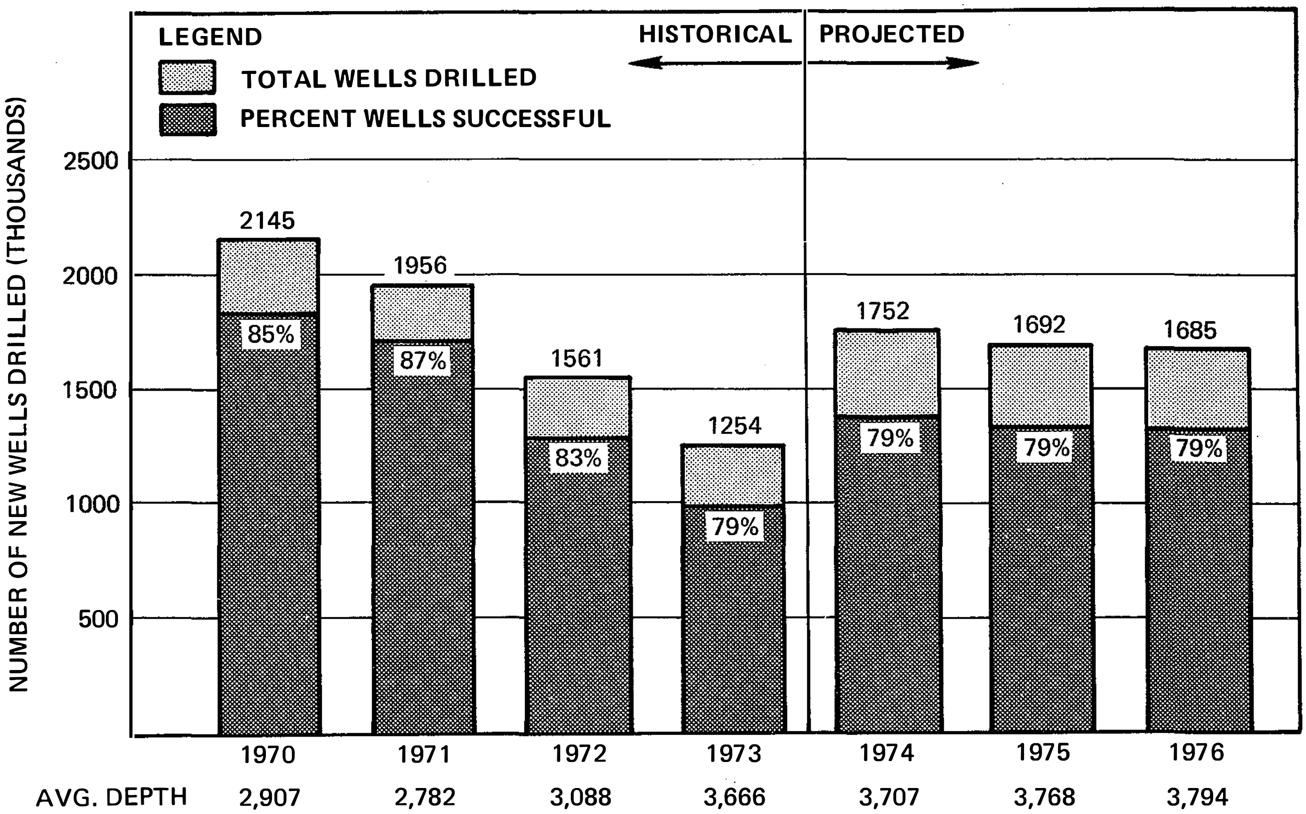


Figure 23. New Wells Drilled--Region No. 2.

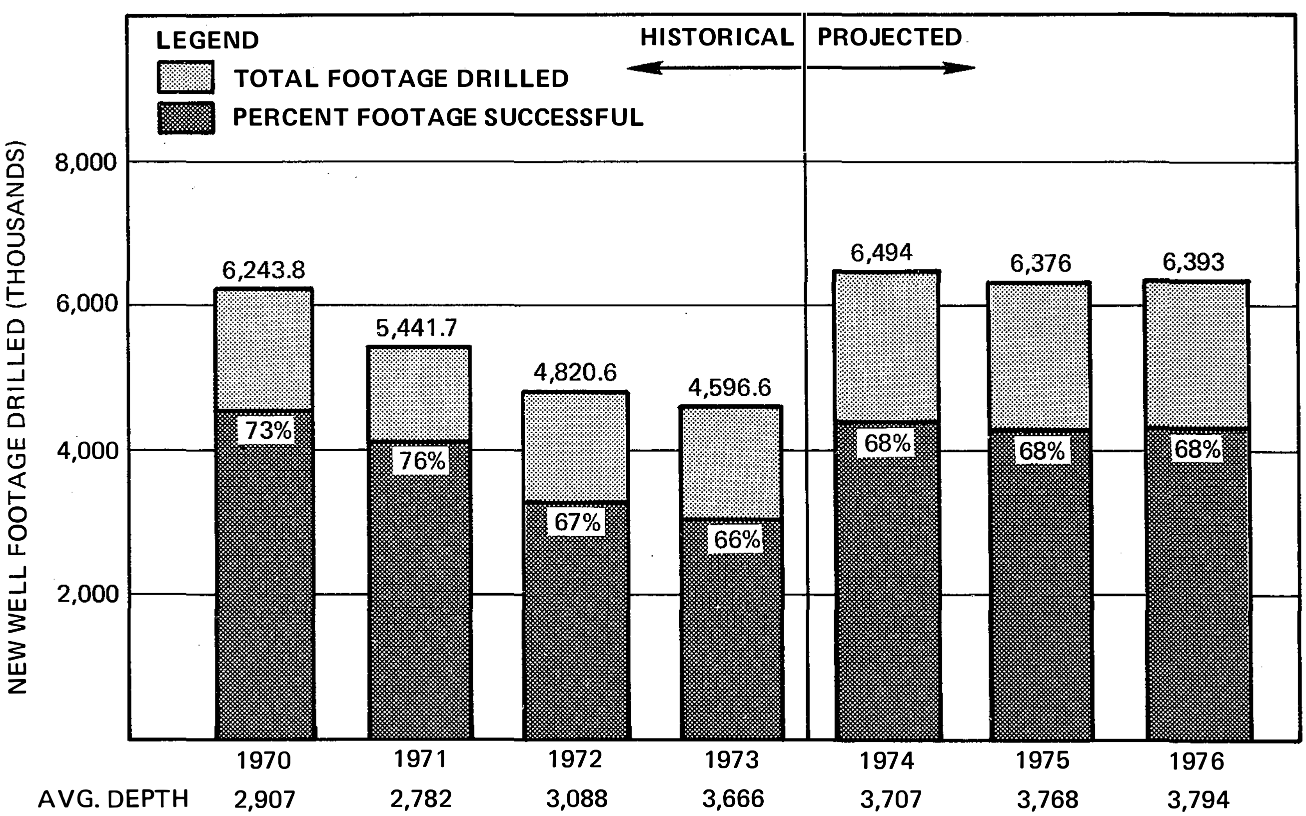


Figure 24. New Well Footage--Region No. 2.

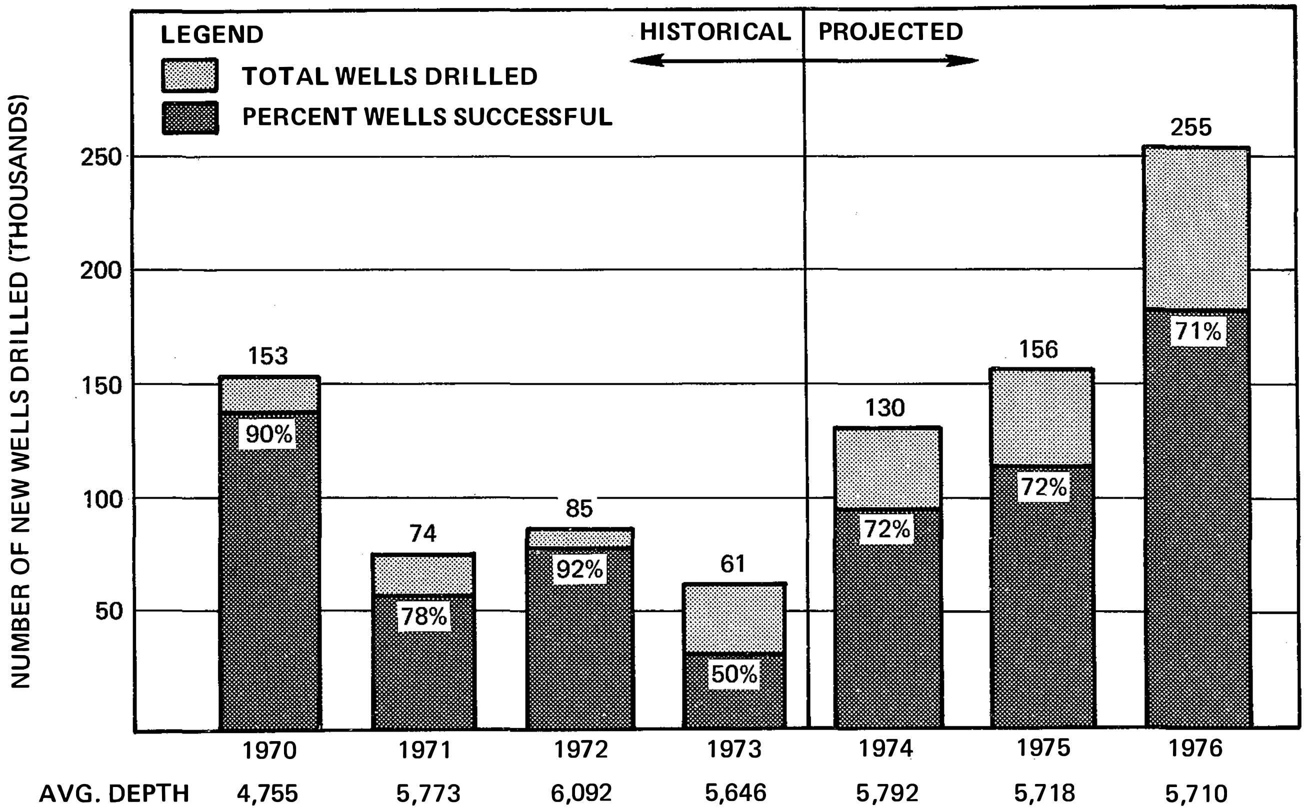


Figure 25. New Wells Drilled--Region No. 2-A.

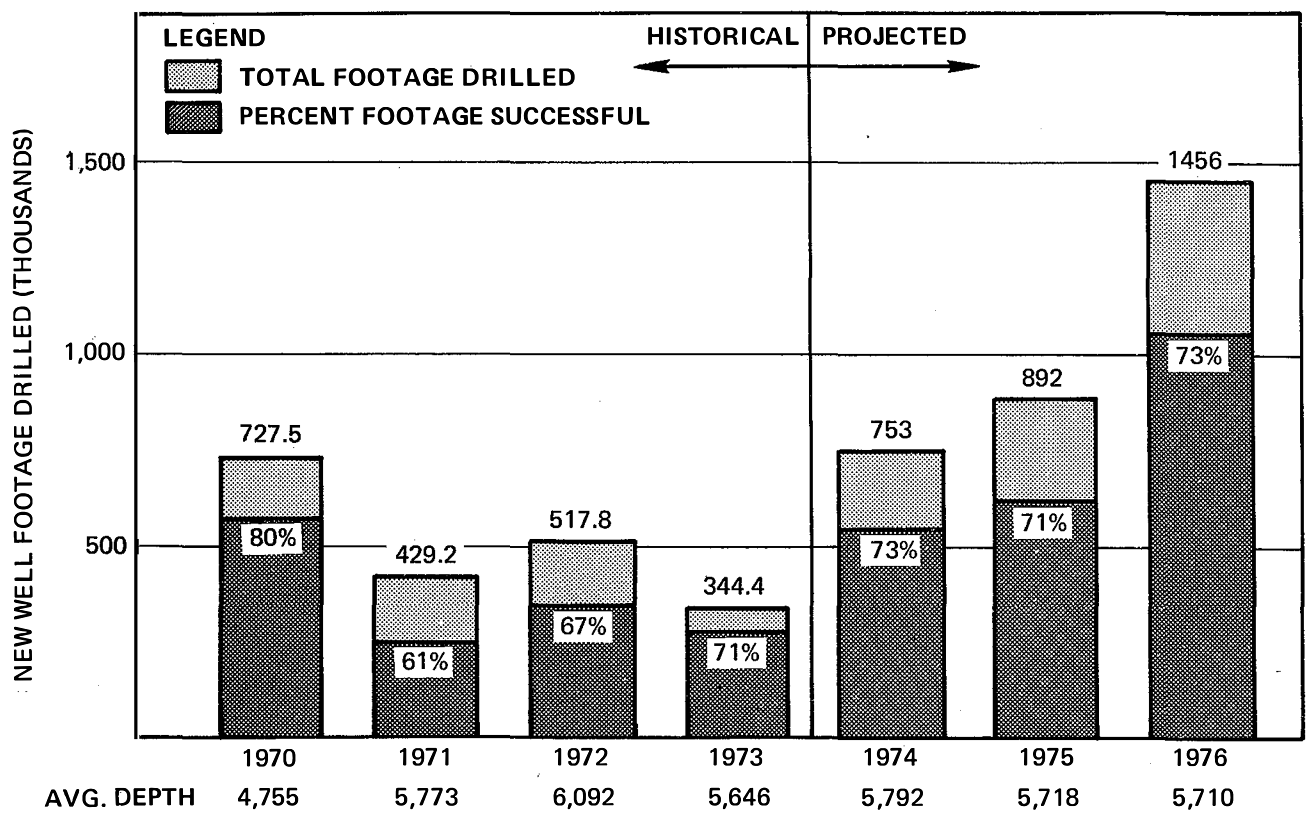


Figure 26. New Well Footage--Region No. 2-A.

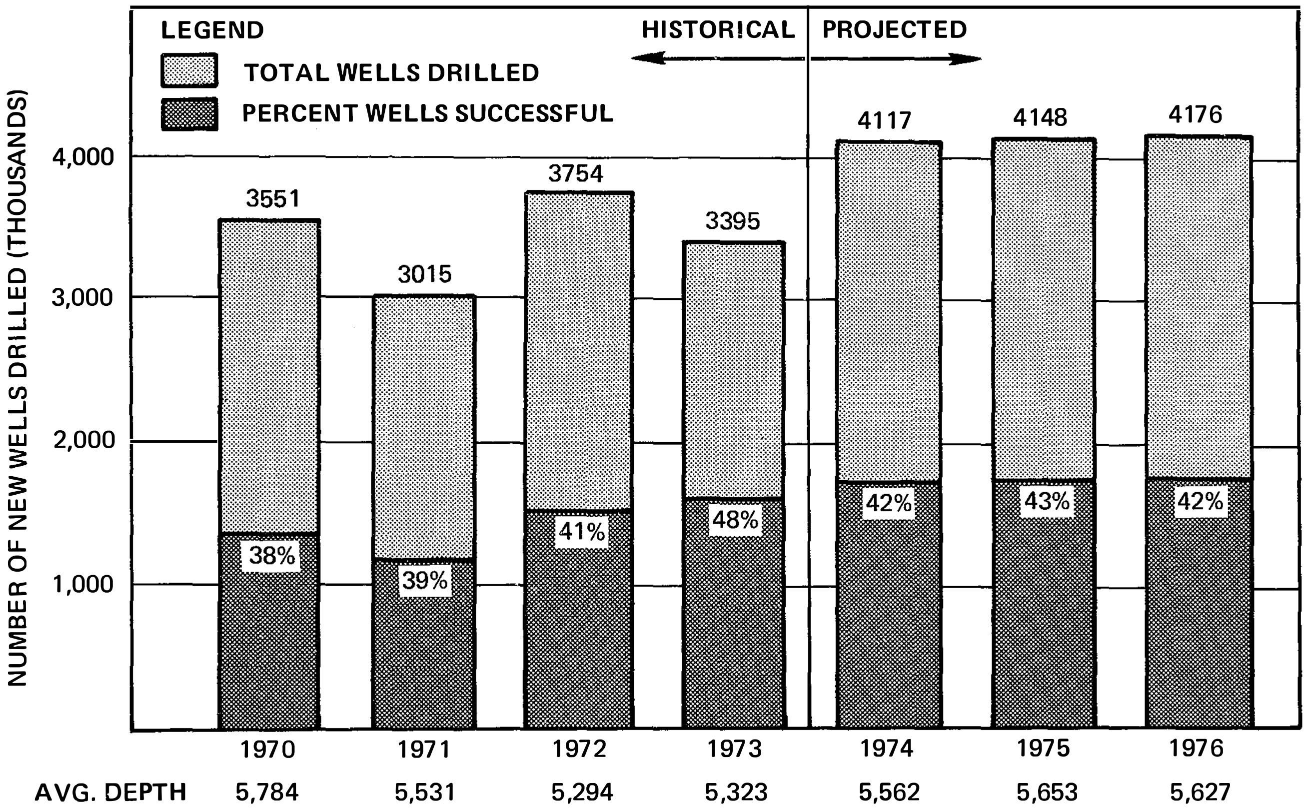


Figure 27. New Wells Drilled--Region No. 3.

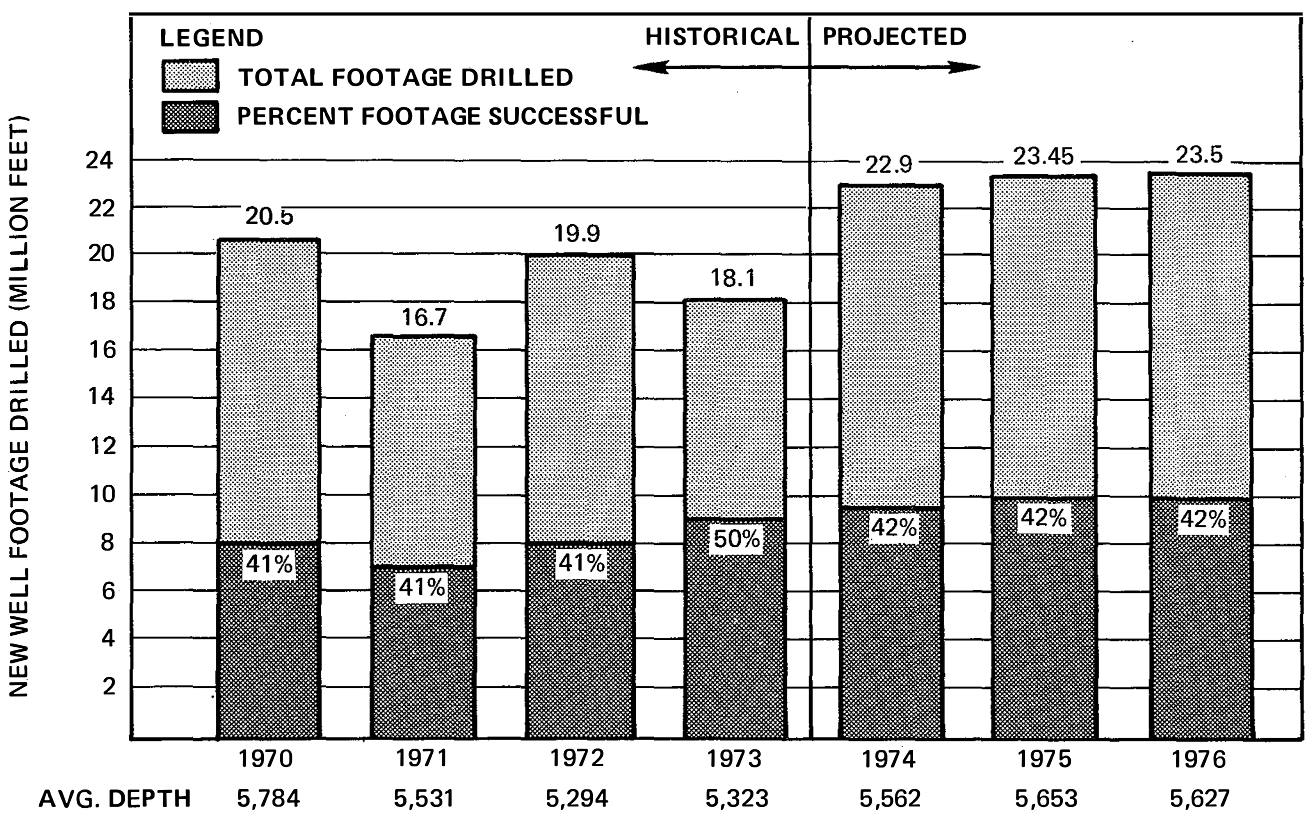


Figure 28. New Well Footage--Region No. 3.

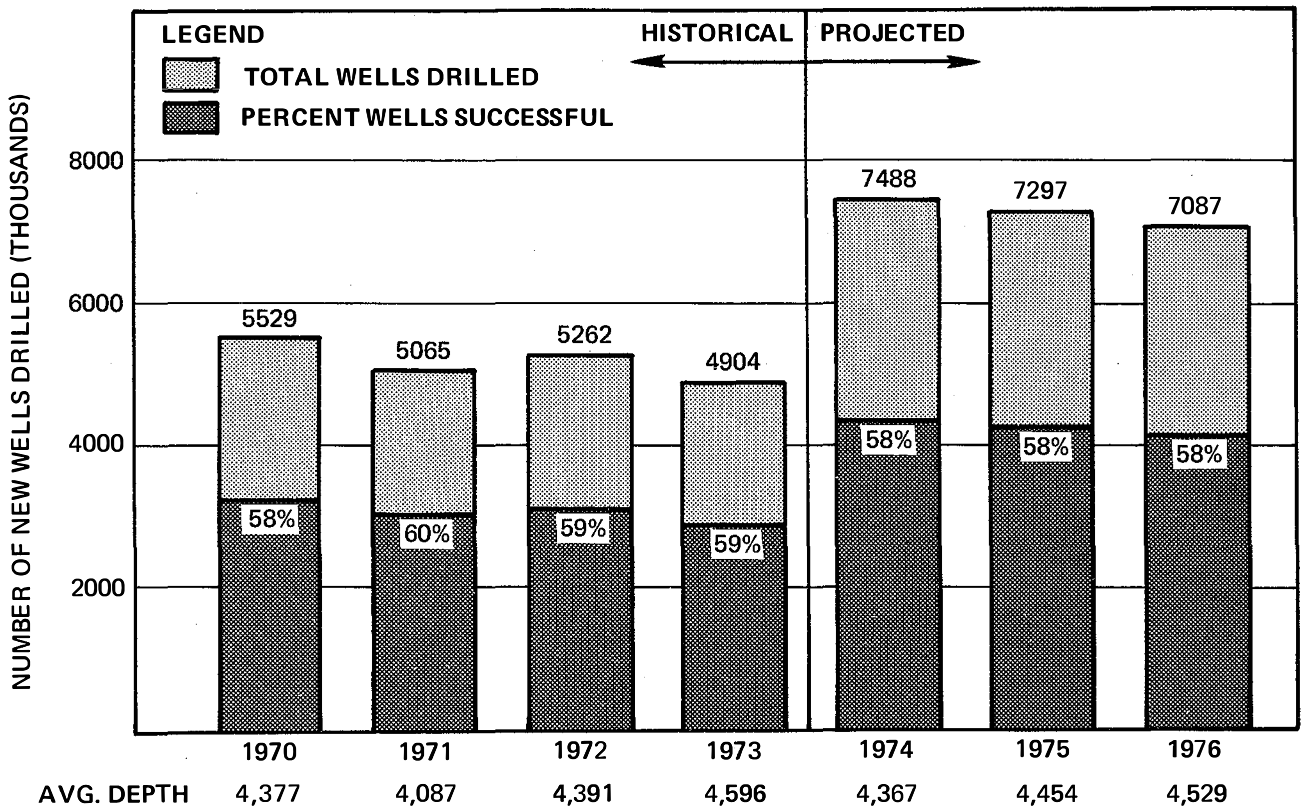


Figure 29. New Wells Drilled--Region No. 4.

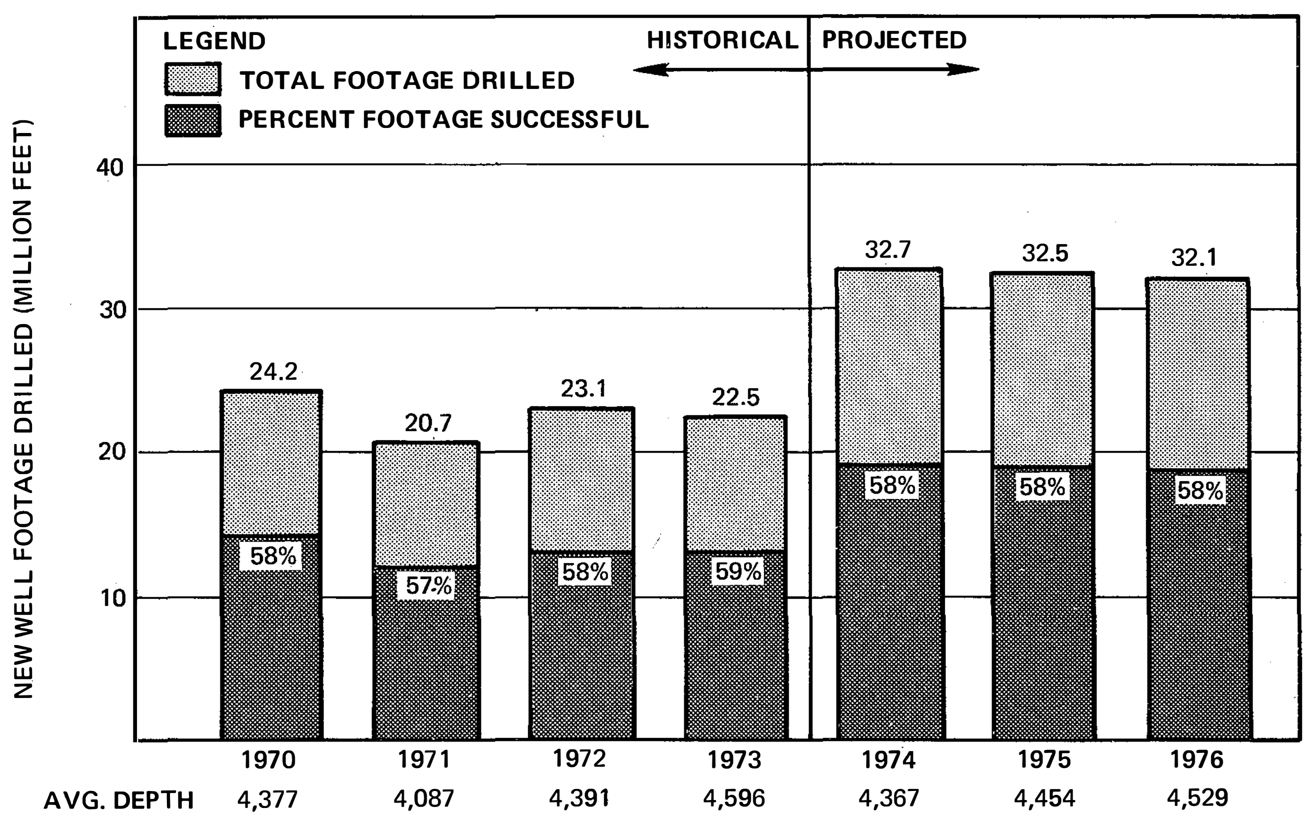


Figure 30. New Well Footage--Region No. 4.

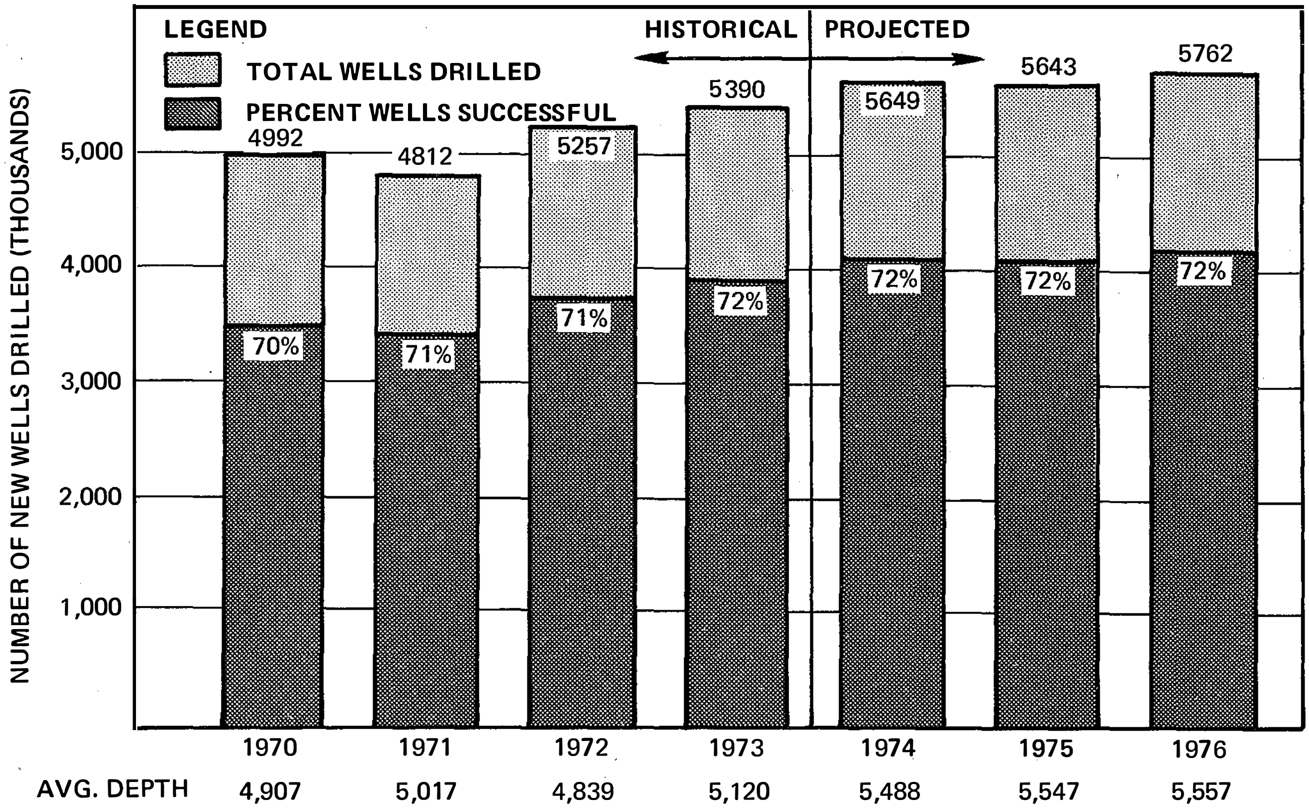


Figure 31. New Wells Drilled--Region No. 5.

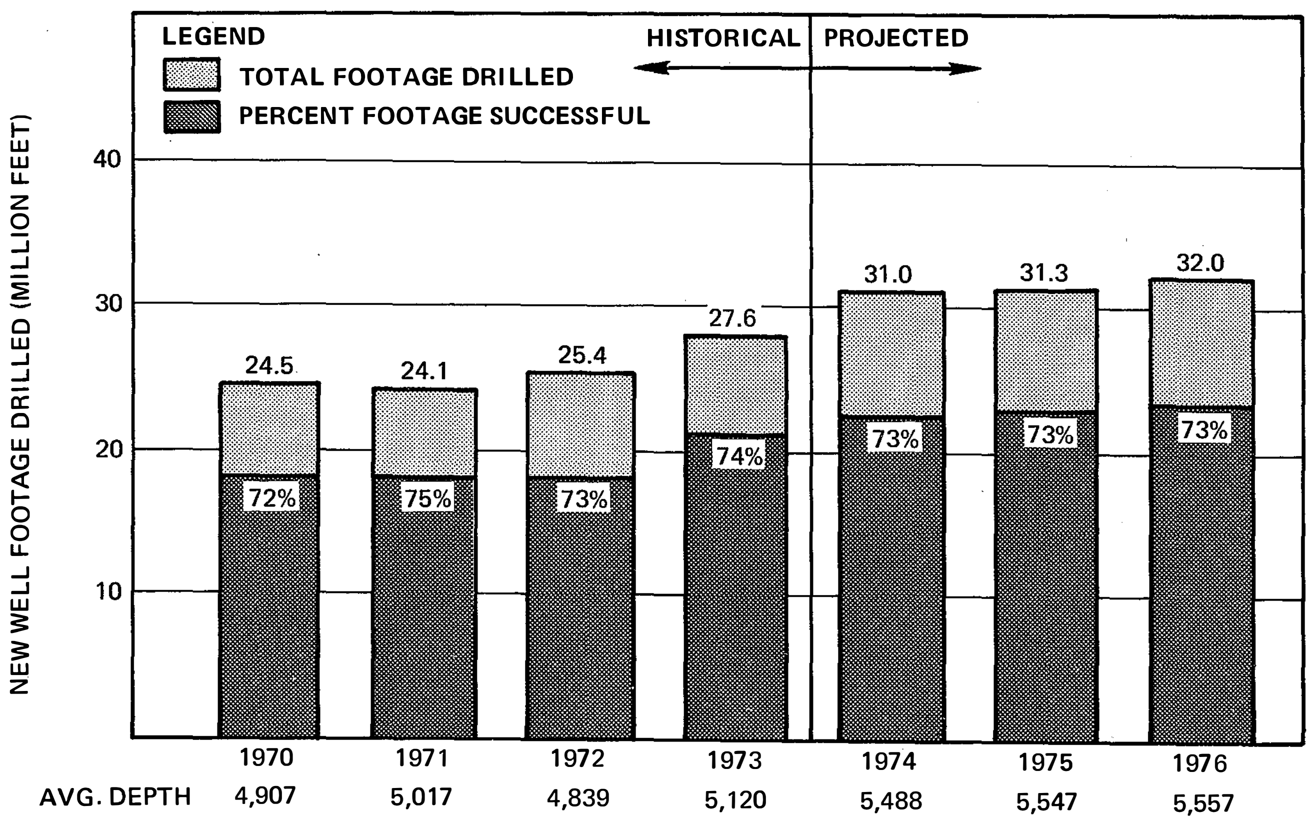


Figure 32. New Well Footage--Region No. 5.

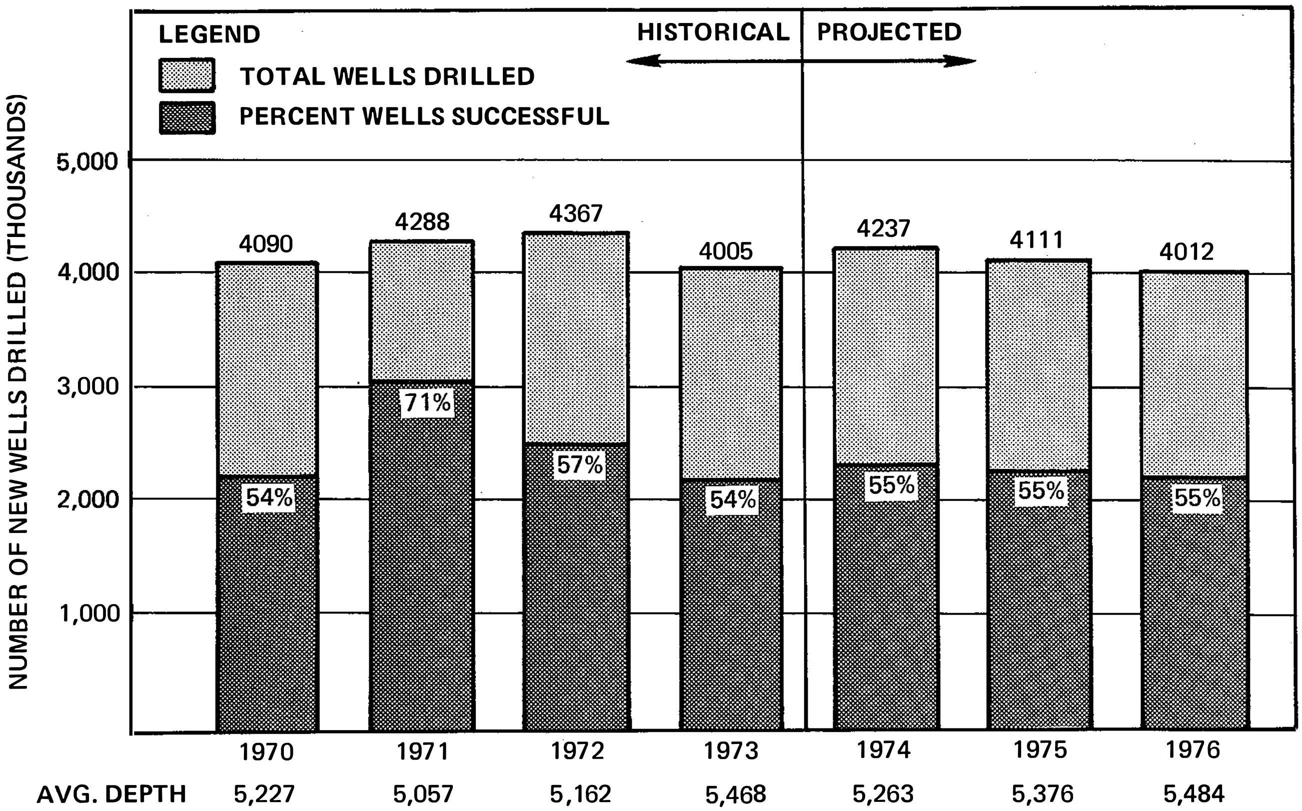


Figure 33. New Wells Drilled--Region No. 6.

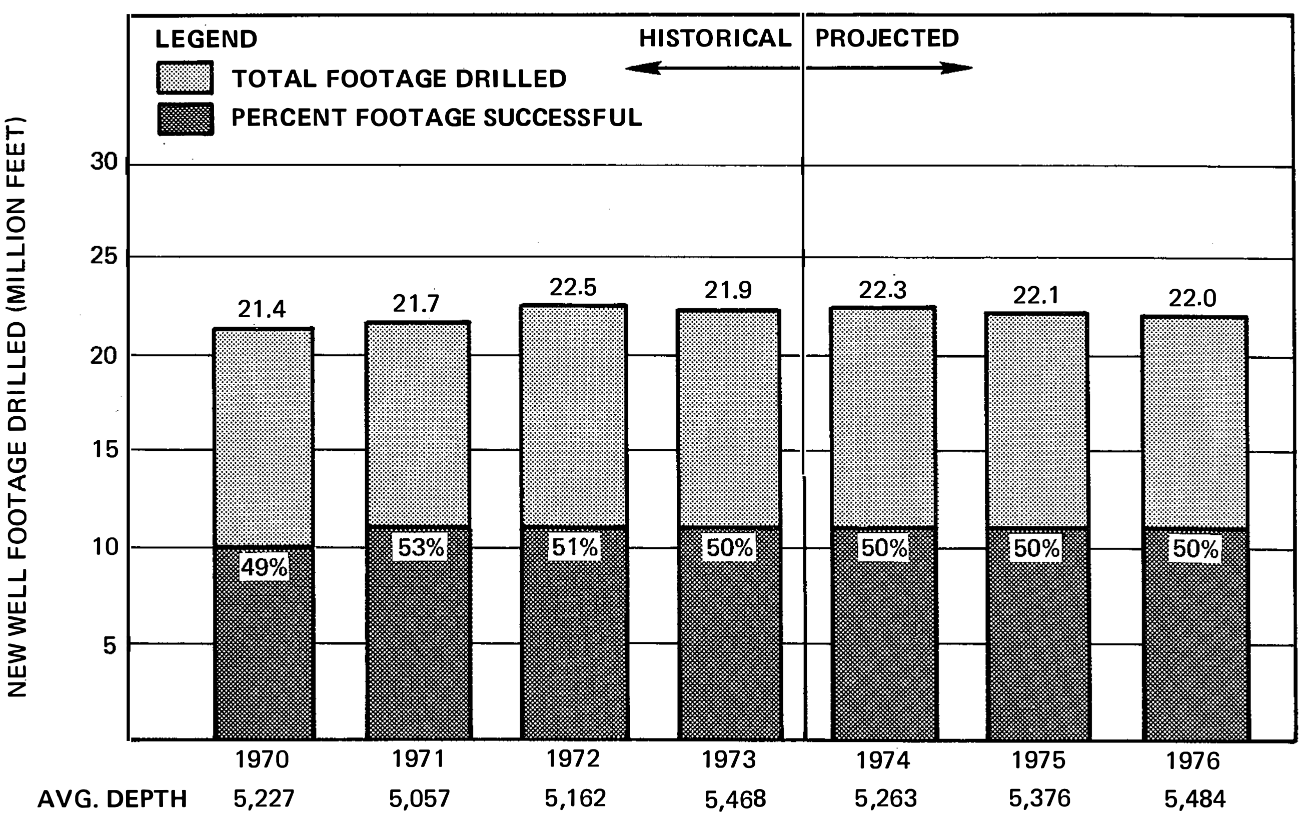


Figure 34. New Well Footage--Region No. 6.

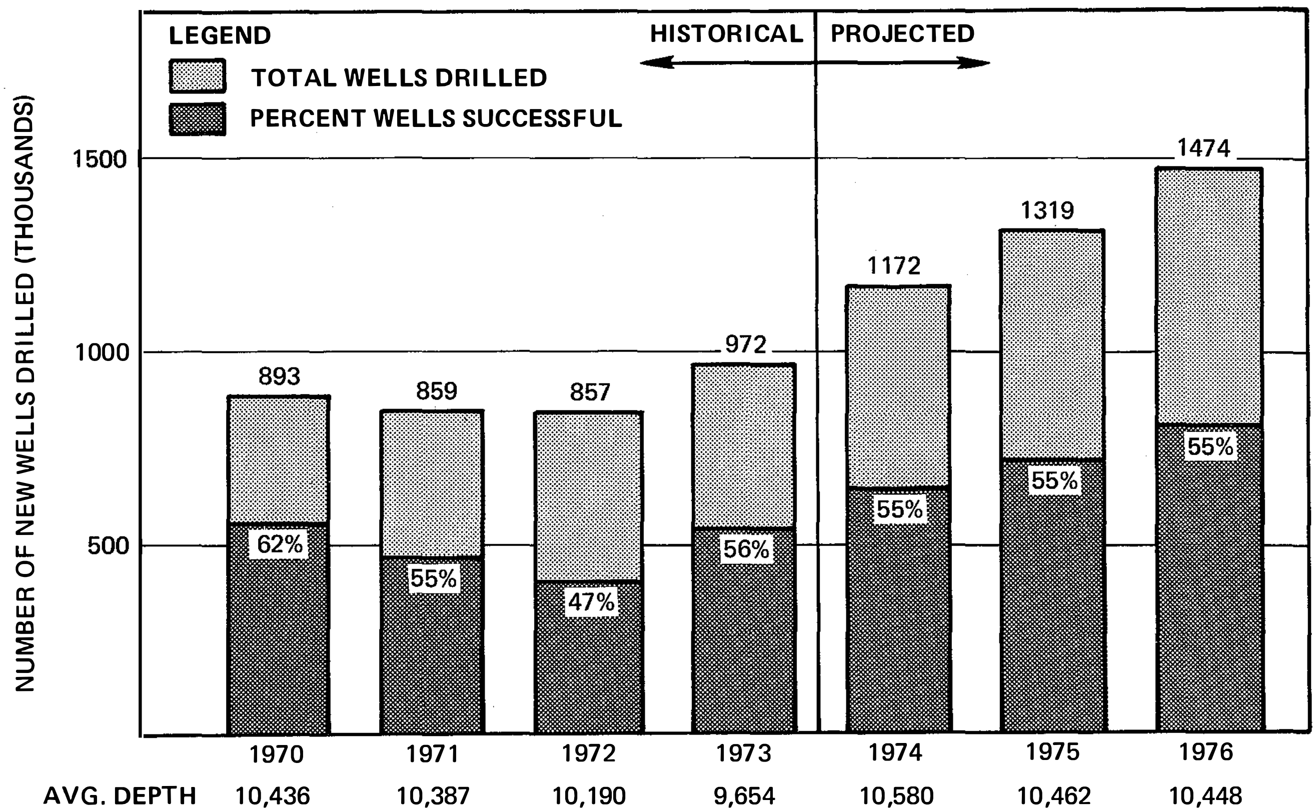


Figure 35. New Wells Drilled--Region No. 6-A.

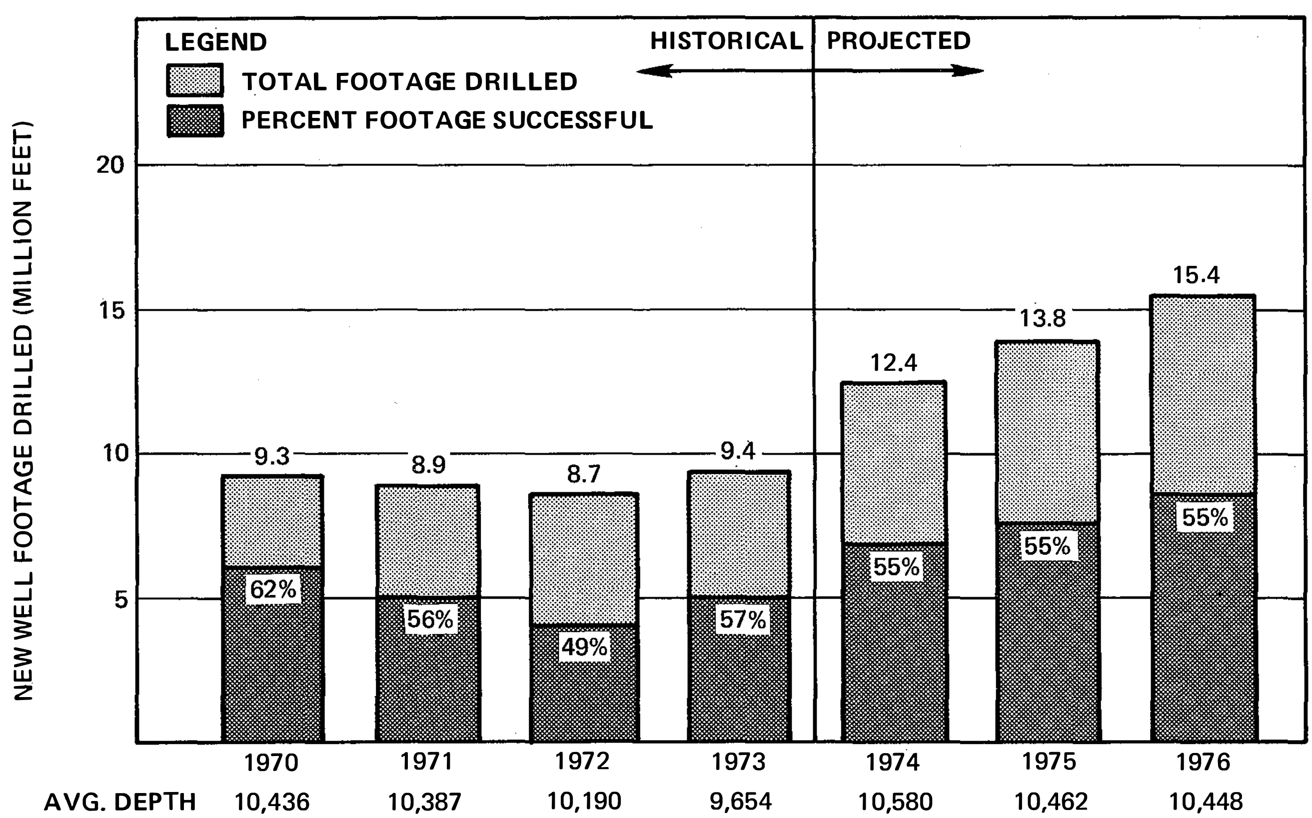


Figure 36. New Well Footage--Region No. 6-A.

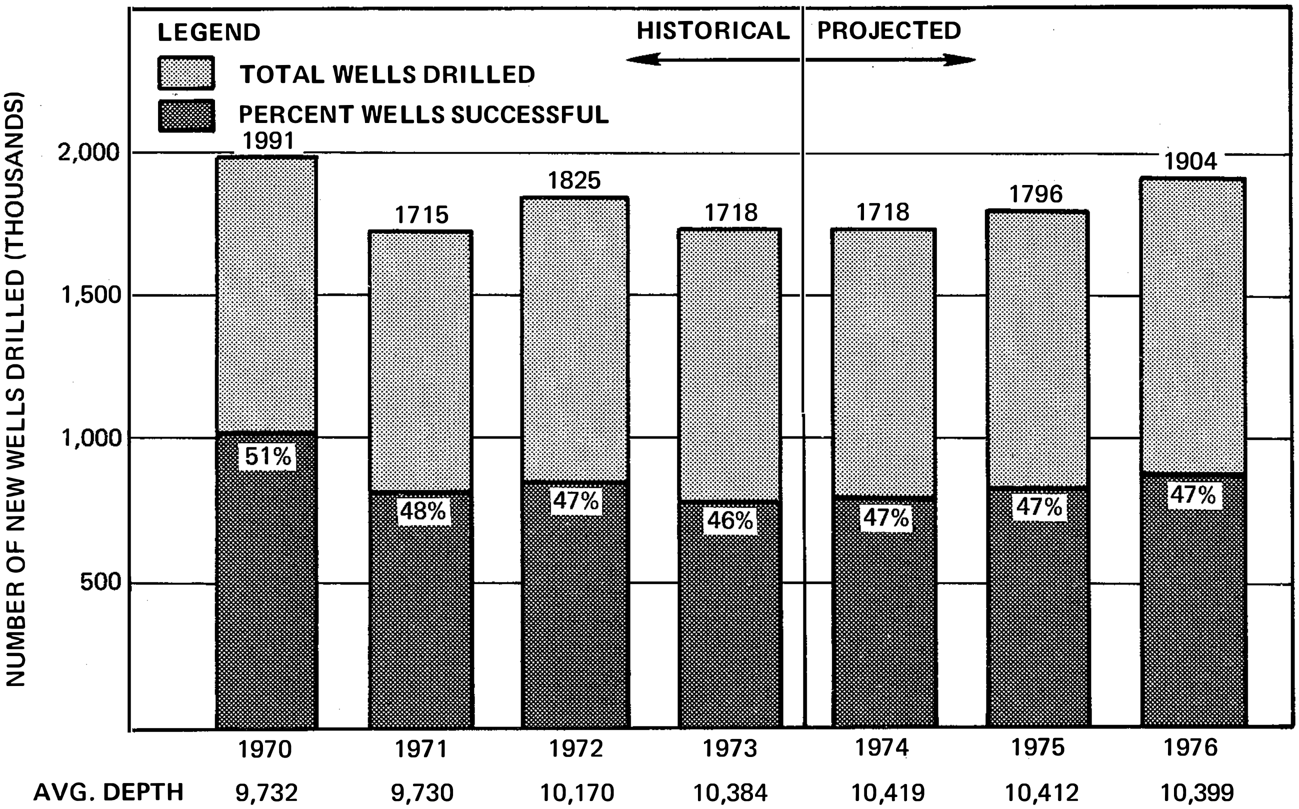


Figure 37. New Wells Drilled--Region No. 7.

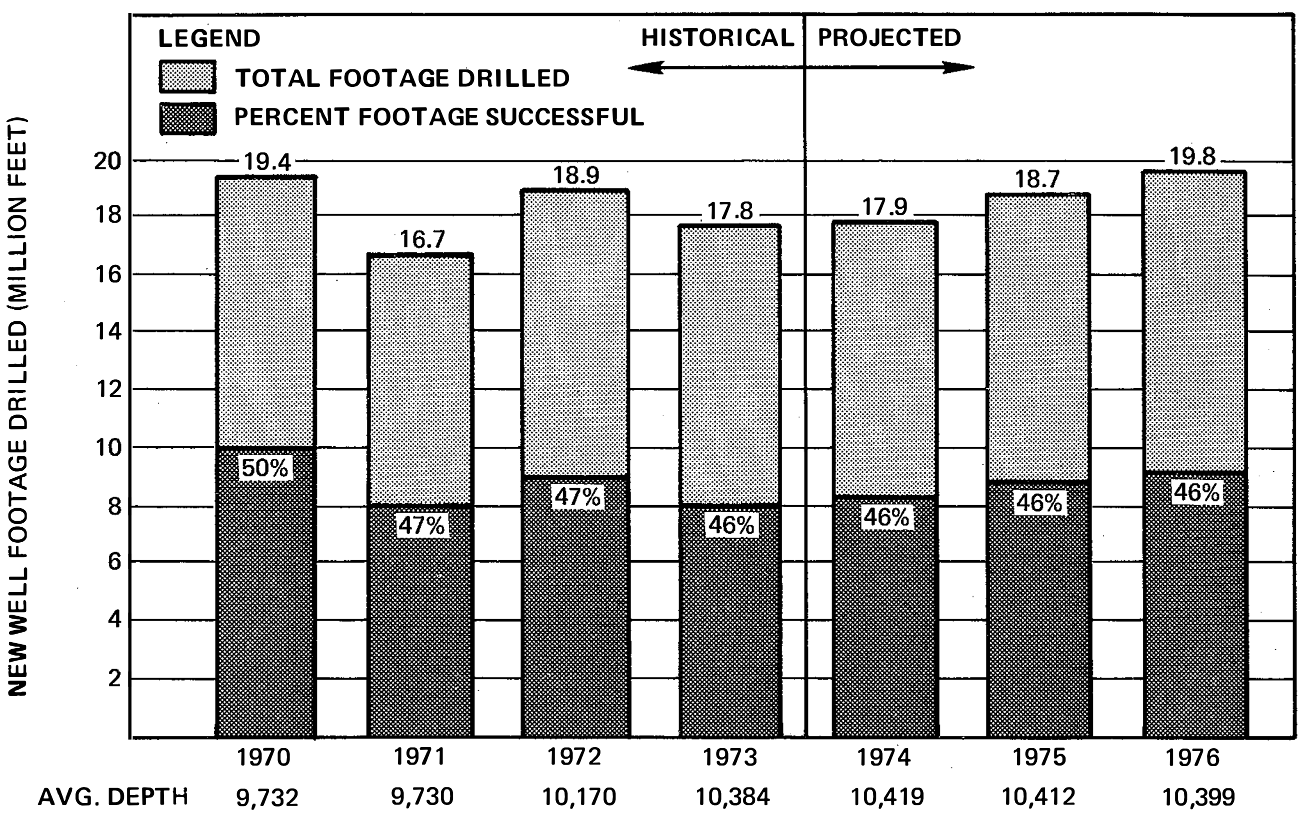


Figure 38. New Well Footage--Region No. 7.

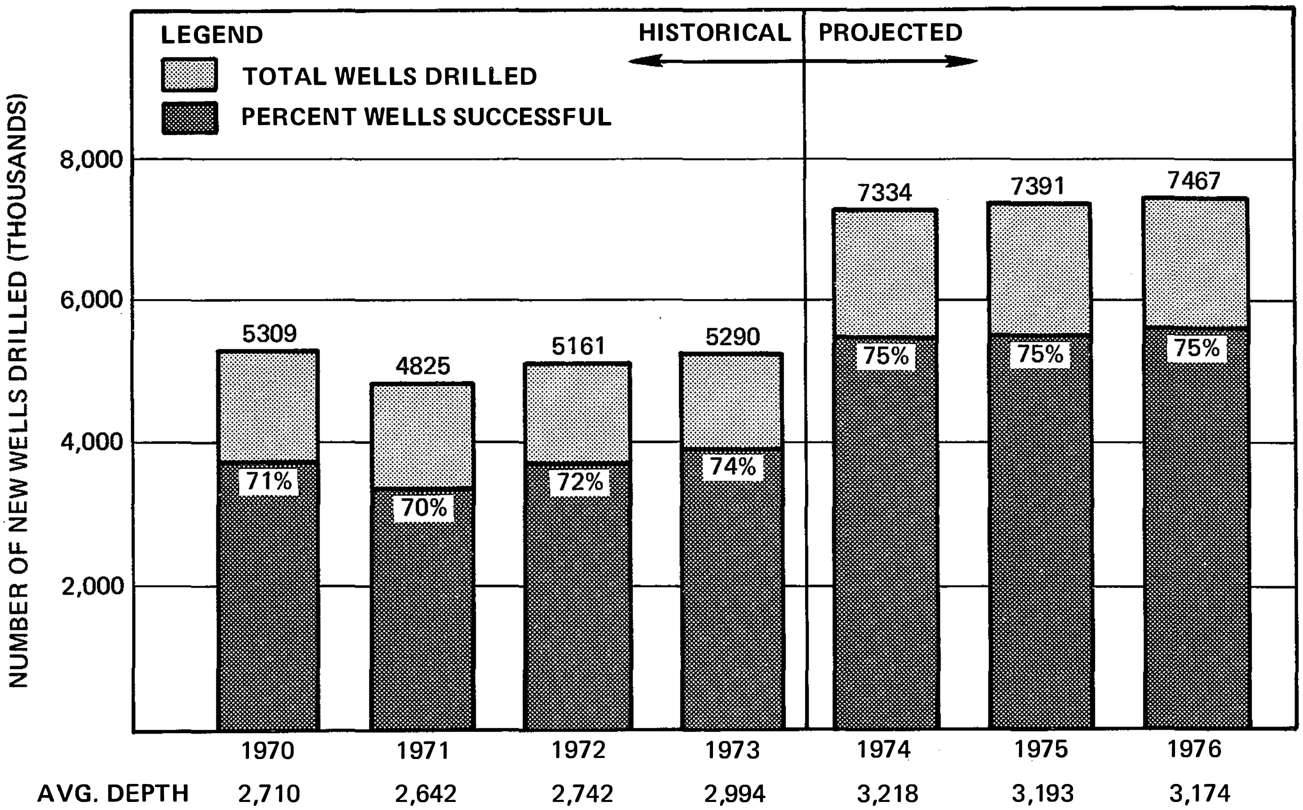


Figure 39. New Wells Drilled--Region No. 8.

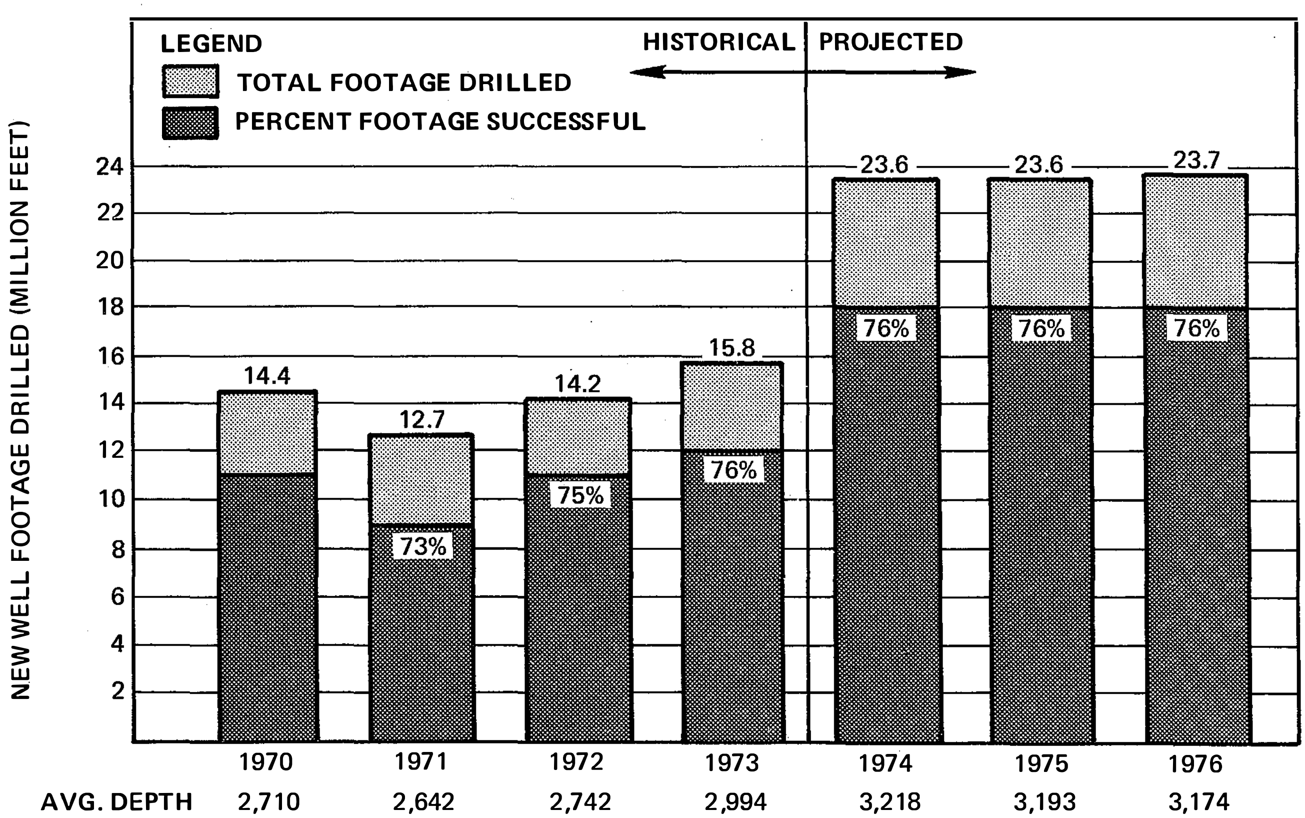


Figure 40. New Well Footage--Region No. 8.

APPENDIX E

Tubular Steel

TABLE 55

TUBULAR STEEL CONSUMED IN REGION 1–1973

(Tons)

Casing and Tubing (Wells–Classified by Depth Category)	Dry Holes	Producing Wells	Total Wells
0' - 2,500'	0	0	0
2,500' - 5,000'	12	244	256
5,000' - 10,000'	41	1,074	1,115
10,000' - 15,000'	97	2,282	2,379
15,000' +	0	1,401	1,401
Total	150	5,001	5,151
Service Wells			0
Line Pipe			985
Total Tubular Steel Consumed in 1973			6,136

TABLE 56

TUBULAR STEEL CONSUMED IN REGION 1A–1973

(Tons)

Casing and Tubing (Wells–Classified by Depth Category)	Dry Holes	Producing Wells	Total Wells
0' - 2,500'	0	0	0
2,500' - 5,000'	0	0	0
5,000' - 10,000'	91	644	735
10,000' - 15,000'	0	1,172	1,172
15,000' +	0	0	0
Total	91	1,816	1,907
Service Wells			214
Line Pipe			249
Total Tubular Steel Consumed in 1973			2,370

TABLE 57

TUBULAR STEEL CONSUMED IN REGION 2–1973

(Tons)

Casing and Tubing (Wells–Classified by Depth Category)	Dry Holes	Producing Wells	Total Wells
0' - 2,500'	1,824	12,750	14,574
2,500' - 5,000'	1,600	11,560	13,160
5,000' - 10,000'	3,286	22,875	26,161
10,000' - 15,000'	502	7,420	7,922
15,000' +	366	1,540	1,906
Total	7,578	56,145	63,723
Service Wells			5,253
Line Pipe			7,142
Total Tubular Steel Consumed in 1973			76,118

TABLE 58

TUBULAR STEEL CONSUMED IN REGION 2A—1973

(Tons)

Casing and Tubing (Wells—Classified by Depth Category)	Dry Holes	Producing Wells	Total Wells
0′ - 2,500′	0	0	0
2,500′ - 5,000′	60	1,380	1,440
5,000′ - 10,000′	0	2,622	2,622
10,000′ - 15,000′	0	753	753
15,000′ +	0	0	0
Total	60	4,755	4,815
Service Wells			528
Line Pipe			1,539
Total Tubular Steel Consumed in 1973			6,882

TABLE 59

TUBULAR STEEL CONSUMED IN REGION 3—1973

(Tons)

Casing and Tubing (Wells—Classified by Depth Category)	Dry Holes	Producing Wells	Total Wells
0′ - 2,500′	2,680	5,400	8,080
2,500′ - 5,000′	6,672	20,148	26,820
5,000′ - 10,000′	22,264	49,938	72,202
10,000′ - 15,000′	8,505	14,308	22,813
15,000′ +	1,092	3,960	5,052
Total	41,213	93,754	134,967
Service Wells			1,680
Line Pipe			10,147
Total Tubular Steel Consumed in 1973			146,794

TABLE 60

TUBULAR STEEL CONSUMED IN REGION 4—1973

(Tons)

Casing and Tubing (Wells—Classified by Depth Category)	Dry Holes	Producing Wells	Total Wells
0′ - 2,500′	2,724	10,200	12,924
2,500′ - 5,000′	12,922	55,104	68,026
5,000′ - 10,000′	10,500	58,829	69,329
10,000′ - 15,000′	9,207	31,496	40,703
15,000′ +	8,120	18,284	26,404
Total	43,473	173,913	217,386
Service Wells			3,700
Line Pipe			18,749
Total Tubular Steel Consumed in 1973			239,835

TABLE 61

TUBULAR STEEL CONSUMED IN REGION 5—1973
(Tons)

Casing and Tubing (Wells—Classified by Depth Category)	Dry Holes	Producing Wells	Total Wells
0′ - 2,500′	2,322	15,283	17,605
2,500′ - 5,000′	4,168	48,440	52,608
5,000′ - 10,000	6,912	107,120	114,032
10,000′ - 15,000′	5,698	48,267	53,965
15,000′ +	9,072	36,895	45,967
Total	**28,172**	**256,005**	**284,177**
Service Wells			9,261
Line Pipe			24,467
Total Tubular Steel Consumed in 1973			**317,905**

TABLE 62

TUBULAR STEEL CONSUMED IN REGION 6—1973
(Tons)

Casing and Tubing (Wells—Classified by Depth Category)	Dry Holes	Producing Wells	Total Wells
0′ - 2,500′	995	16,464	17,459
2,500′ - 5,000′	6,799	21,504	28,303
5,000′ - 10,000′	32,585	80,496	113,081
10,000′ - 15,000′	30,360	58,254	88,614
15,000′ +	3,064	2,214	5,278
Total	**43,803**	**178,932**	**252,735**
Service Wells			2,460
Line Pipe			19,153
Total Tubular Steel Consumed in 1973			**274,348**

TABLE 63

TUBULAR STEEL CONSUMED IN REGION 6A—1973
(Tons)

Casing and Tubing (Wells—Classified by Depth Category)	Dry Holes	Producing Wells	Total Wells
0′ - 2,500′	48	27	75
2,500′ - 5,000′	624	1,090	1,714
5,000′ - 10,000′	30,784	68,419	99,203
10,000′ - 15,000′	44,370	110,112	154,482
15,000′ +	10,788	25,038	35,826
Total	**86,614**	**204,686**	**291,300**
Service Wells			4,848
Line Pipe			14,844
Total Tubular Steel Consumed in 1973			**310,992**

TABLE 64

TUBULAR STEEL CONSUMED IN REGION 7–1973

(Tons)

Casing and Tubing (Wells—Classified by Depth Category)	Dry Holes	Producing Wells	Total Wells
0′ - 2,500′	190	648	838
2,500′ - 5,000′	1,425	3,068	4,493
5,000′ - 10,000′	21,168	34,320	55,488
10,000′ - 15,000′	46,690	76,806	123,496
15,000′ +	27,813	57,403	85,216
Total	**97,286**	**172,245**	**269,531**
Service Wells			1,326
Line Pipe			9,684
Total Tubular Steel Consumed in 1973			**280,541**

TABLE 65

TUBULAR STEEL CONSUMED IN REGION 8–1973

(Tons)

Casing and Tubing (Wells—Classified by Depth Category)	Dry Holes	Producing Wells	Total Wells
0′ - 2,500	4,599	33,725	38,324
2,500′ - 5,000′	11,120	82,500	93,620
5,000′ - 10,000′	7,363	52,283	59,646
10,000′ - 15,000′	116	872	988
15,000′ +	–	–	–
Total	**13,198**	**169,380**	**192,578**
Service Wells			3,220
Line Pipe			25,016
Total Tubular Steel Consumed in 1973			**220,814**

TABLE 66

SERVICE WELL STEEL CONSUMPTION BY GEOGRAPHIC REGION–1973

(Casing and Tubing)

NPC Region	Number of Wells*	Tubular Steel Consumed (Tons)
1	0	–
1A	1	214
2	103	5,253
2A	11	528
3	40	1,680
4	185	3,700
5	343	9,261
6	82	2,460
6A	16	4,848
7	17	1,326
8	161	3,220
Total	**959**	**32,490**

*Includes secondary recovery injection wells and disposal wells.

TABLE 67

PROJECTED SERVICE WELLS STEEL CONSUMPTION
BY GEOGRAPHIC REGION—1974-1976
(Casing and Tubing)

	1974		1975		1976	
NPC Region	Number of Wells	Tubular Steel Requirement (Tons)	Number of Wells	Tubular Steel Requirement (Tons)	Number of Wells	Tubular Steel Requirement (Tons)
1	–	–	–	–	–	–
1A	–	–	–	–	–	–
2	126	6,426	126	6,426	127	6,477
2A	14	672	14	672	15	720
3	49	2,058	49	2,058	49	2,058
4	227	4,540	227	4,540	229	4,580
5	421	11,367	421	11,367	426	11,502
6	101	3,030	101	3,030	101	3,030
6A	20	6,060	20	6,060	20	6,060
7	21	1,638	21	1,638	22	1,716
8	198	3,960	198	3,960	200	4,000
Total	**1,177**	**39,751**	**1,177**	**39,751**	**1,189**	**40,143**

TABLE 68

PROJECTED TUBULAR REQUIREMENTS FOR LINE PIPE
BY GEOGRAPHIC REGION—1974-1976
(Tons)

NPC Region	1974	1975	1976
1	2,720	6,450	8,665
1A	240	270	360
2	9,014	8,845	8,802
2A	2,606	3,096	5,145
3	10,119	10,228	10,274
4	25,663	25,066	24,405
5	26,424	26,389	26,944
6	18,407	18,026	17,710
6A	21,870	24,240	26,820
7	9,151	9,362	9,657
8	34,101	34,199	34,548
Total	**160,318**	**166,171**	**173,330**

TABLE 69

DOMESTIC MILL SHIPMENTS—OIL COUNTRY TUBULAR GOODS (OCTG)
(Thousand Tons)

Historical	Carbon Steel	High Strength* Steel	Total Steel	Percent High Strength
1967	777	563	1,340	42.0
1968	856	627	1,483	42.3
1969	833	567	1,400	40.5
1970	740	567	1,307	43.4
1971	758	646	1,404	46.0
1972	715	562	1,277	44.0
1973	941	795	1,736	45.8
Projected				
1974	1,142	964	2,106	45.8
1975	1,235	1,082	2,317	46.7
1976	1,271	1,161	2,432	47.8

*Includes all C-75 and higher grades

TABLE 70

DOMESTIC TUBULAR STEEL CONSUMPTION (DEMAND)—OIL COUNTRY TUBULAR GOODS (OCTG)

(Thousand Tons)

Historical	Carbon Steel	High Strength* Steel	Total Steel	Percent Alloy
1970	1,359	515	1,874	27.4
1971	1,238	425	1,662	25.5
1972	1,297	519	1,816	28.6
1973	1,306	556	1,862	29.8
Projected				
1974	1,644	619	2,263	27.4
1975	1,700	659	2,359	27.9
1976	1,758	715	2,473	28.9

*Includes all C-75 and higher grades

TABLE 71

OIL COUNTRY TUBULAR GOODS AVAILABILITY—1973

(Thousand Tons)

	Carbon	High Strength	Total
Shipped from Domestic Mills	941	795	1,736
Less Shipments to Operator Inventory	145	122	267
Shipped for Consumption	796	673	1,469
Less Exports (60 Percent High Strength)	79	119	198
Shipped for Domestic Consumption	717	554	1,271
Plus Imports (15 Percent High Strength)	138	24	162
	855	578	1,433
Miscellaneous Sources	429	0	429
Total Available for Domestic Consumption	1,284	578	1,862
Percent by Grade	69.0	31.0	100.0

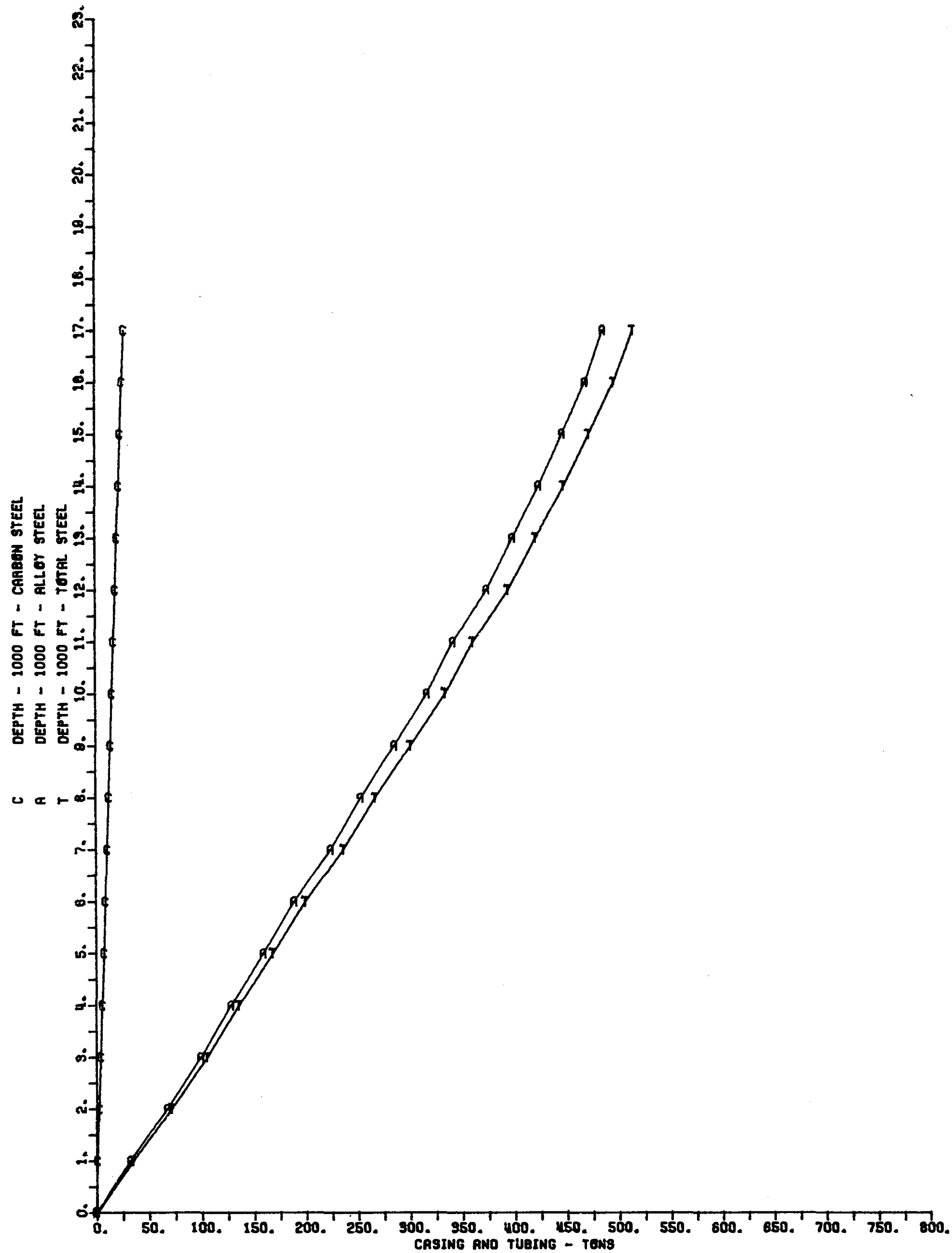


Figure 41. Producing Well - Region 1.

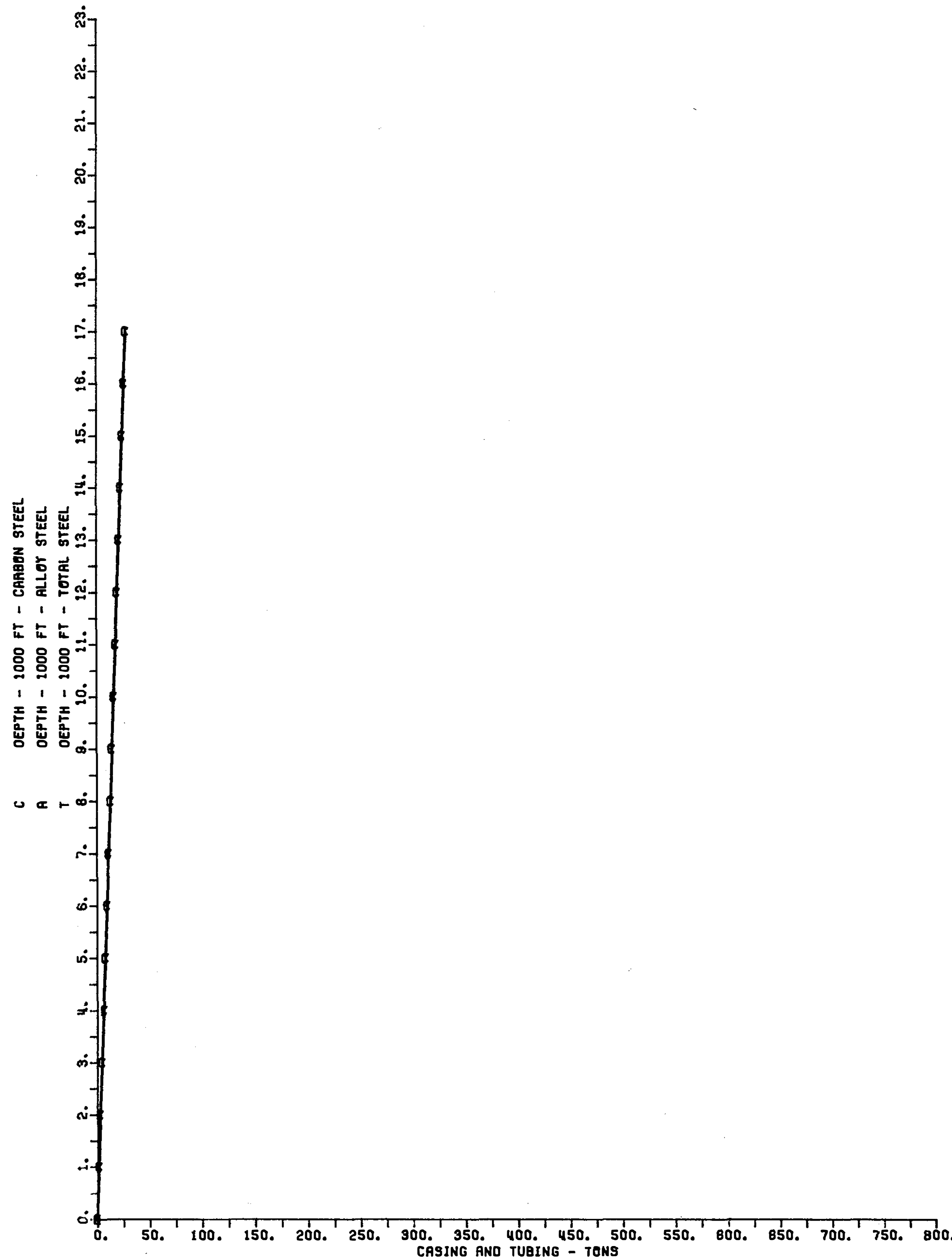


Figure 42. Dry Hole - Region 1.

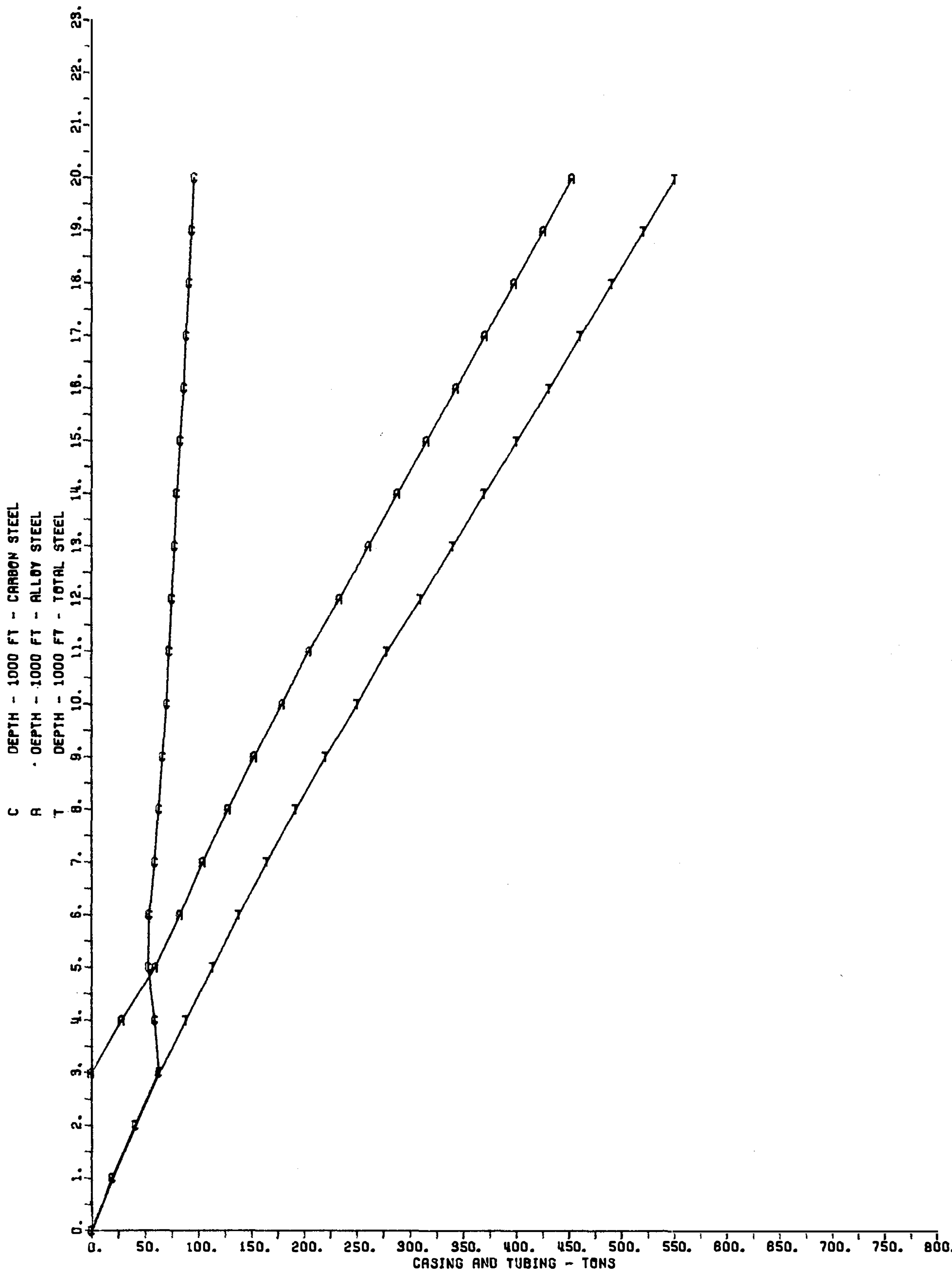


Figure 43. Producing Well - Region 1A & 2A.

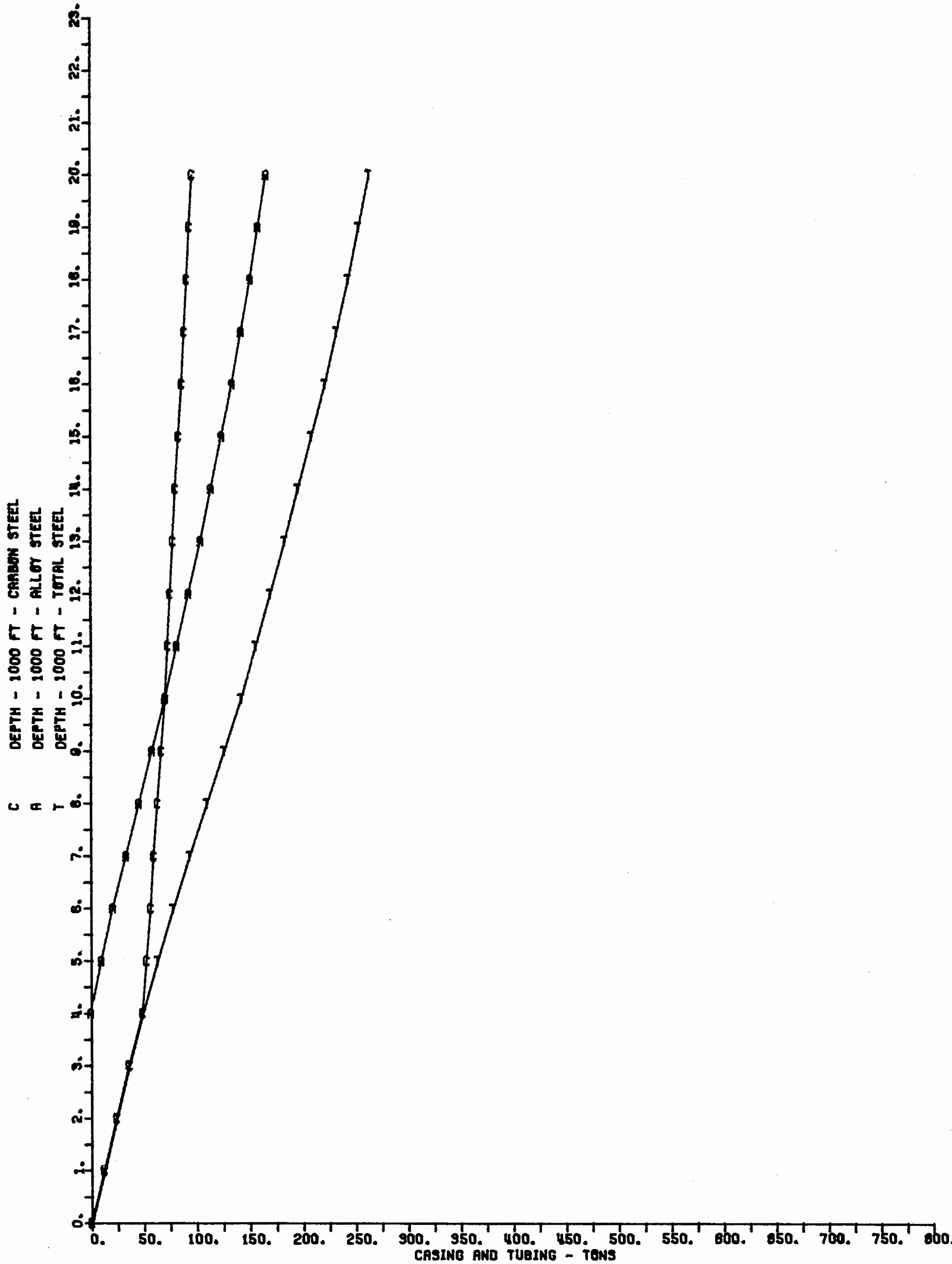


Figure 44. Dry Hole - Region 1A & 2A.

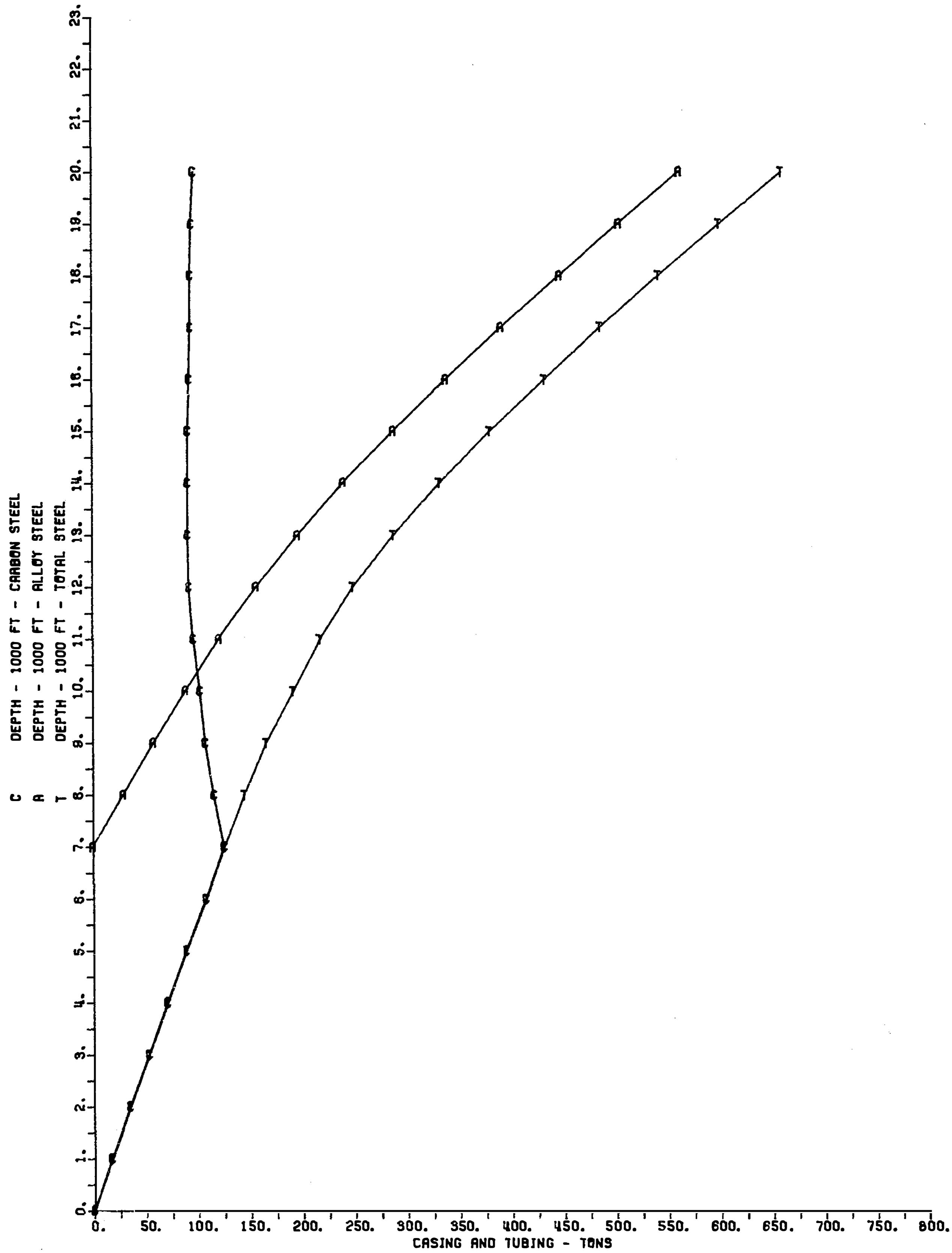


Figure 45. Producing Well - Region 2.

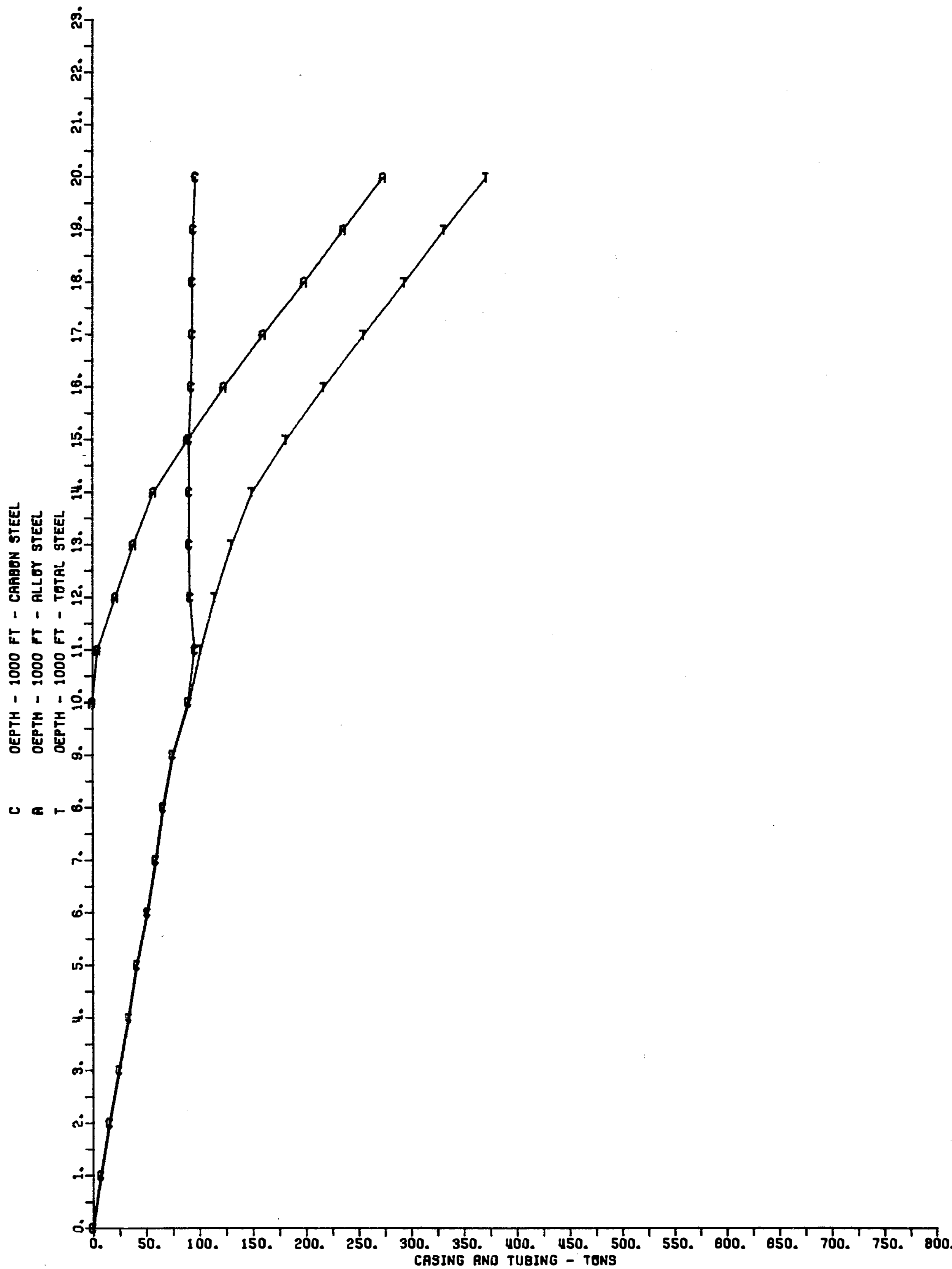


Figure 46. Dry Hole - Region 2.

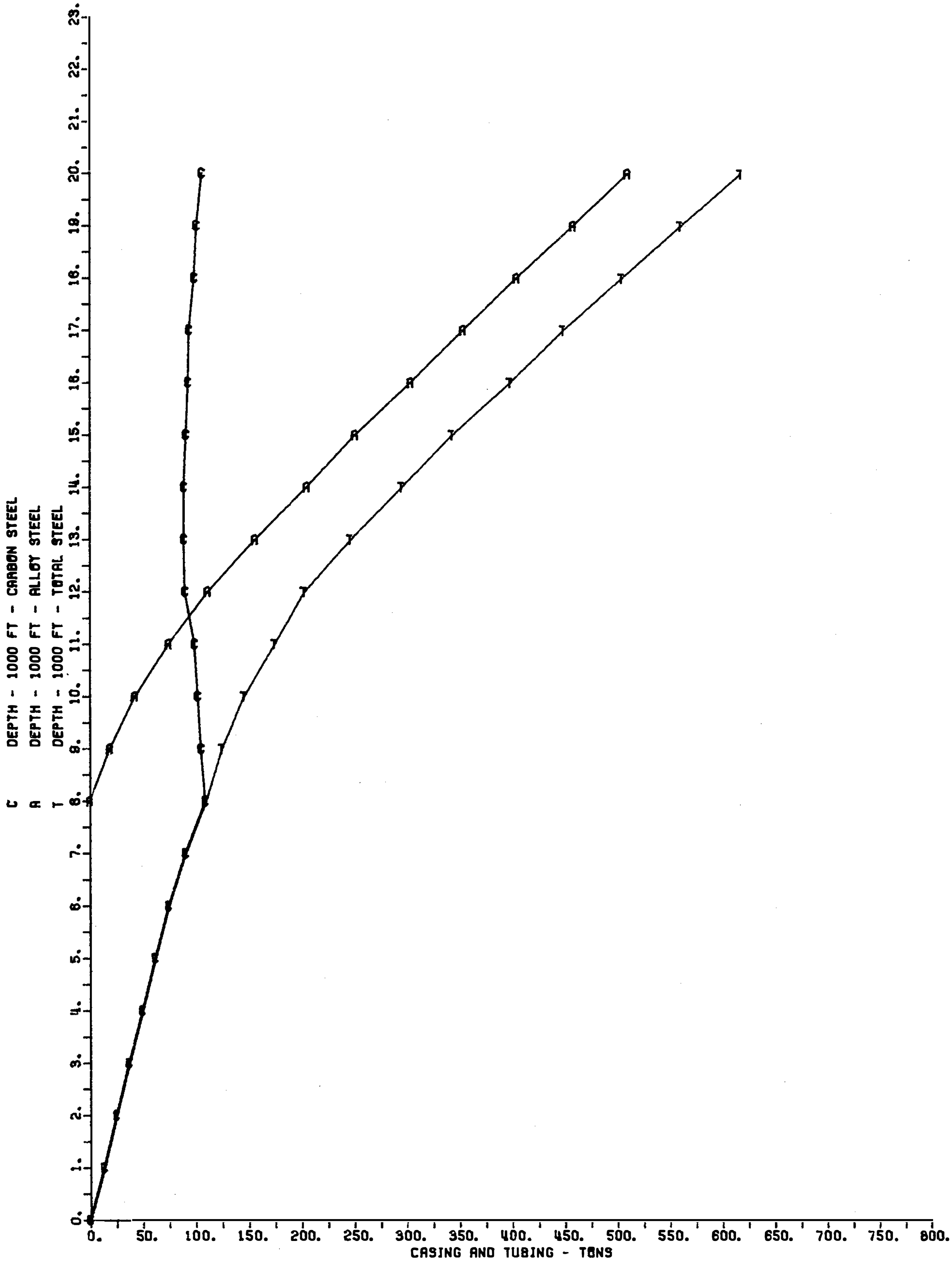


Figure 47. Producing Well - Region 3.

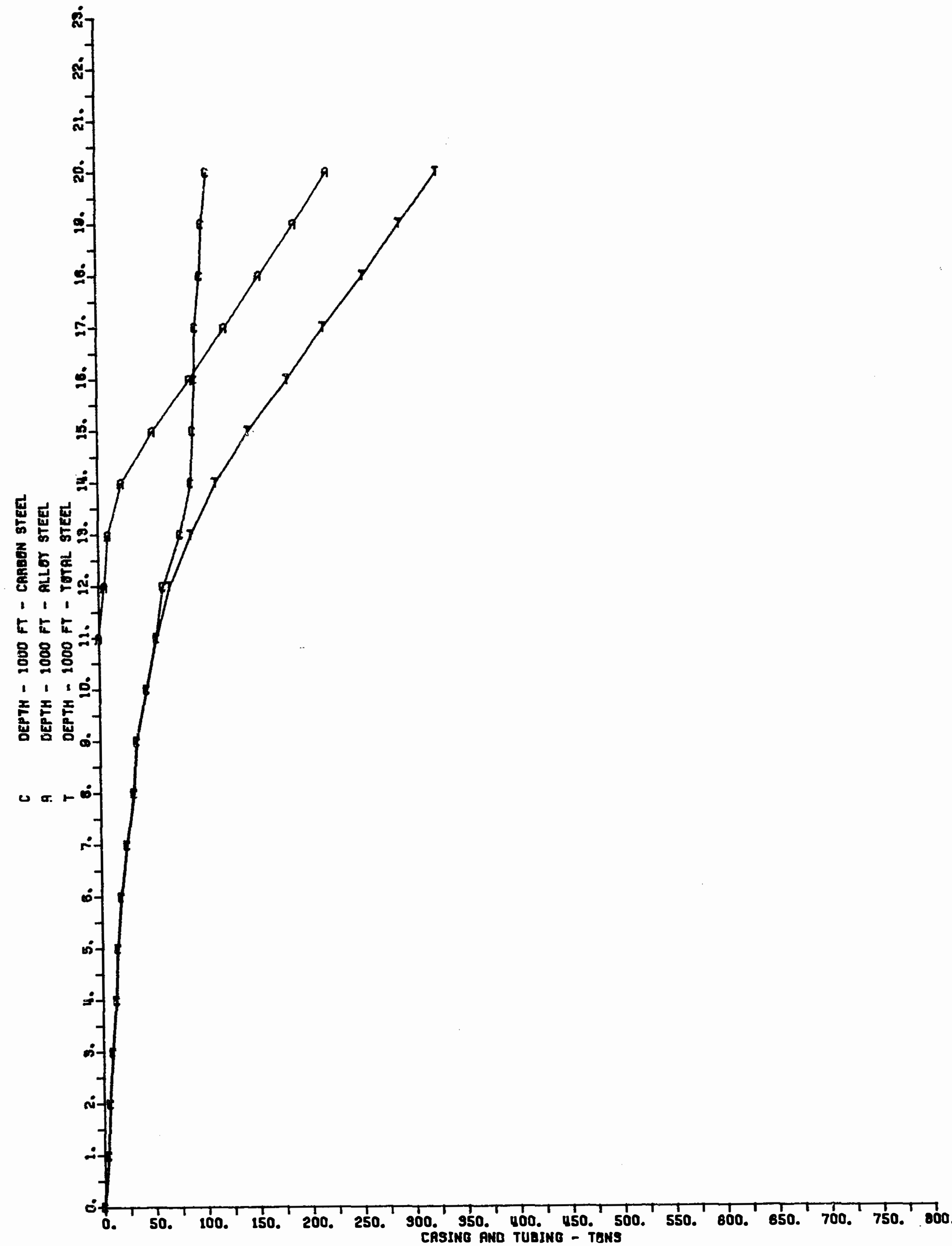


Figure 48. Dry Hole - Region 3.

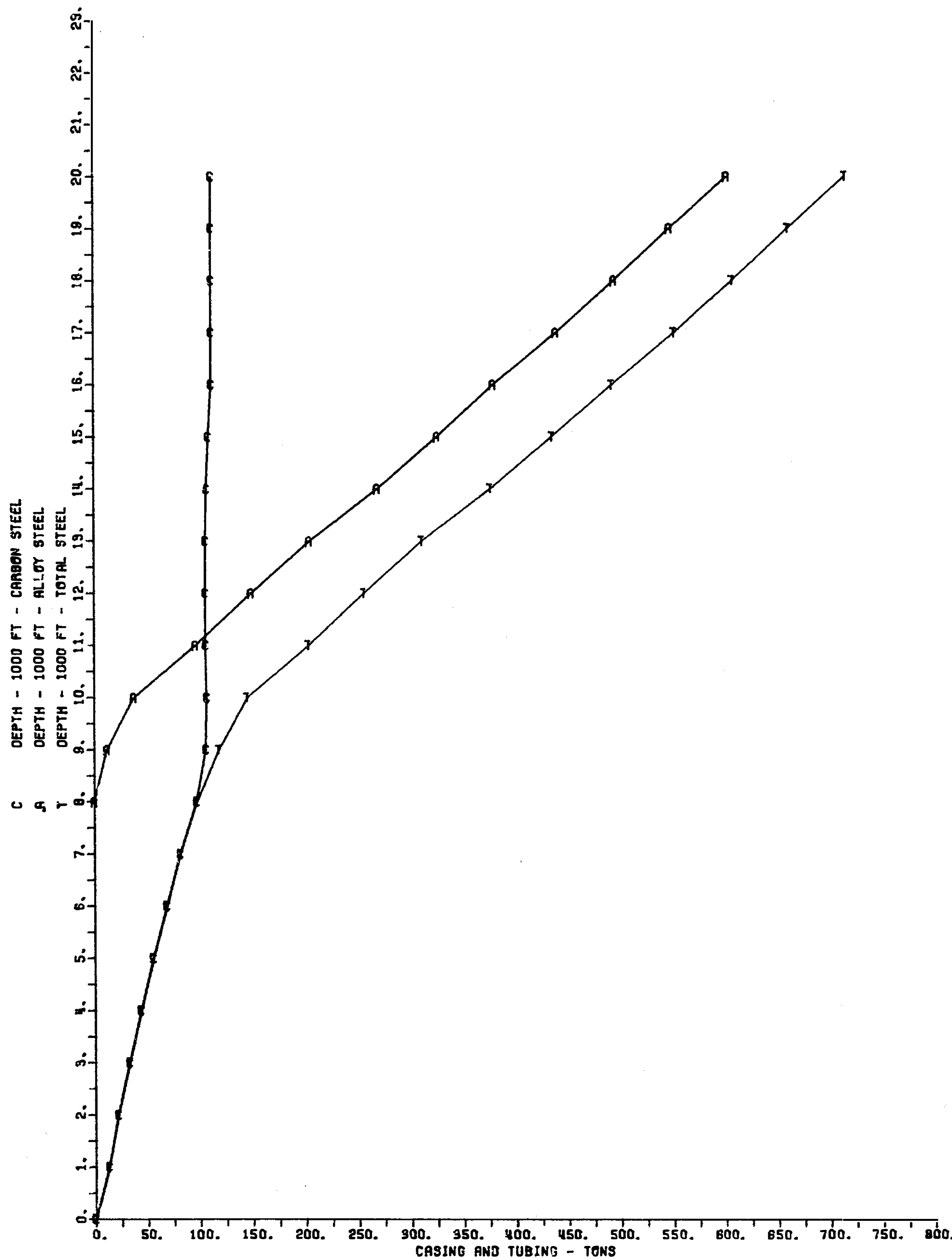


Figure 49. Producing Well - Region 4.

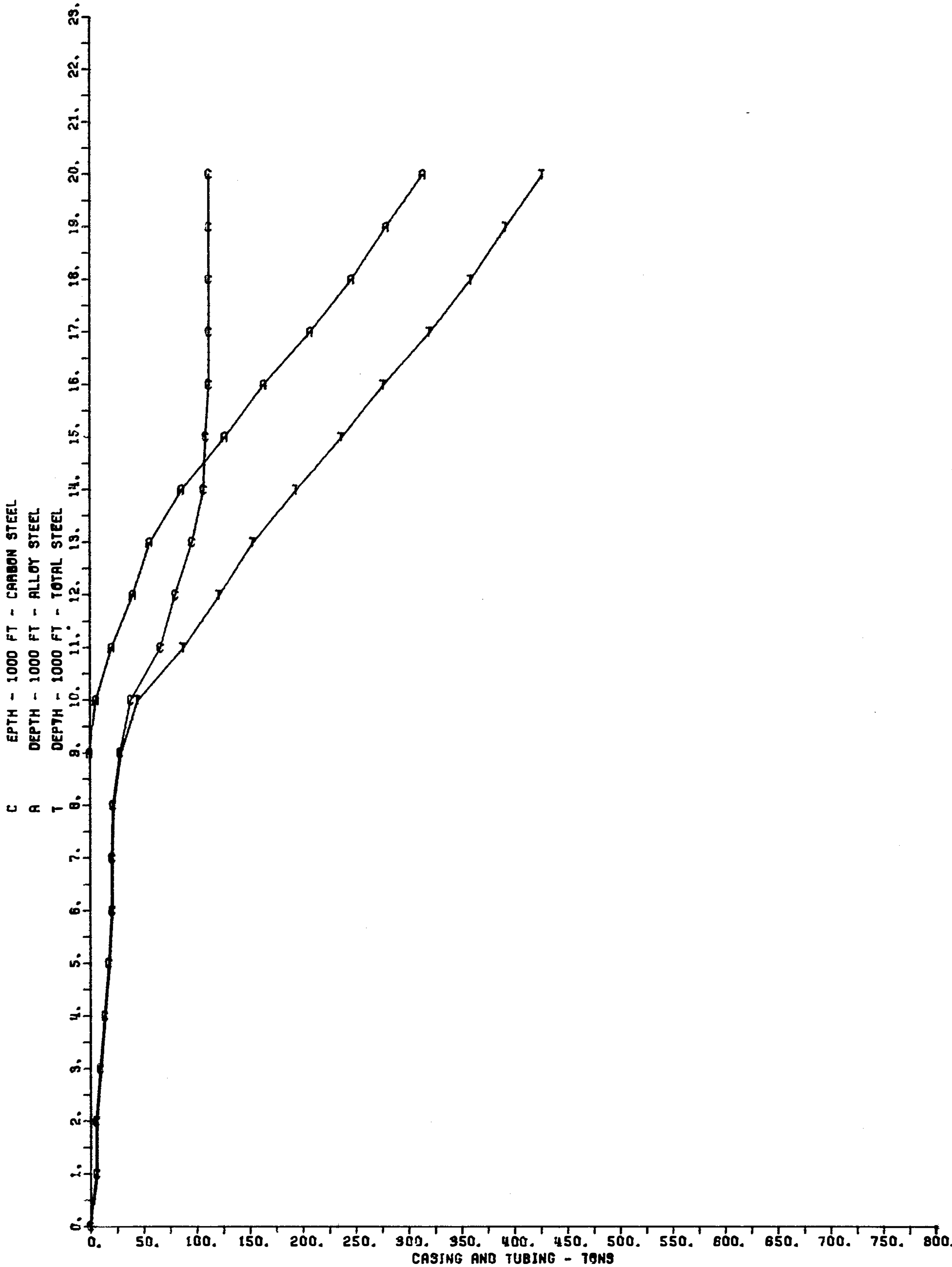


Figure 50. Dry Hole - Region 4.

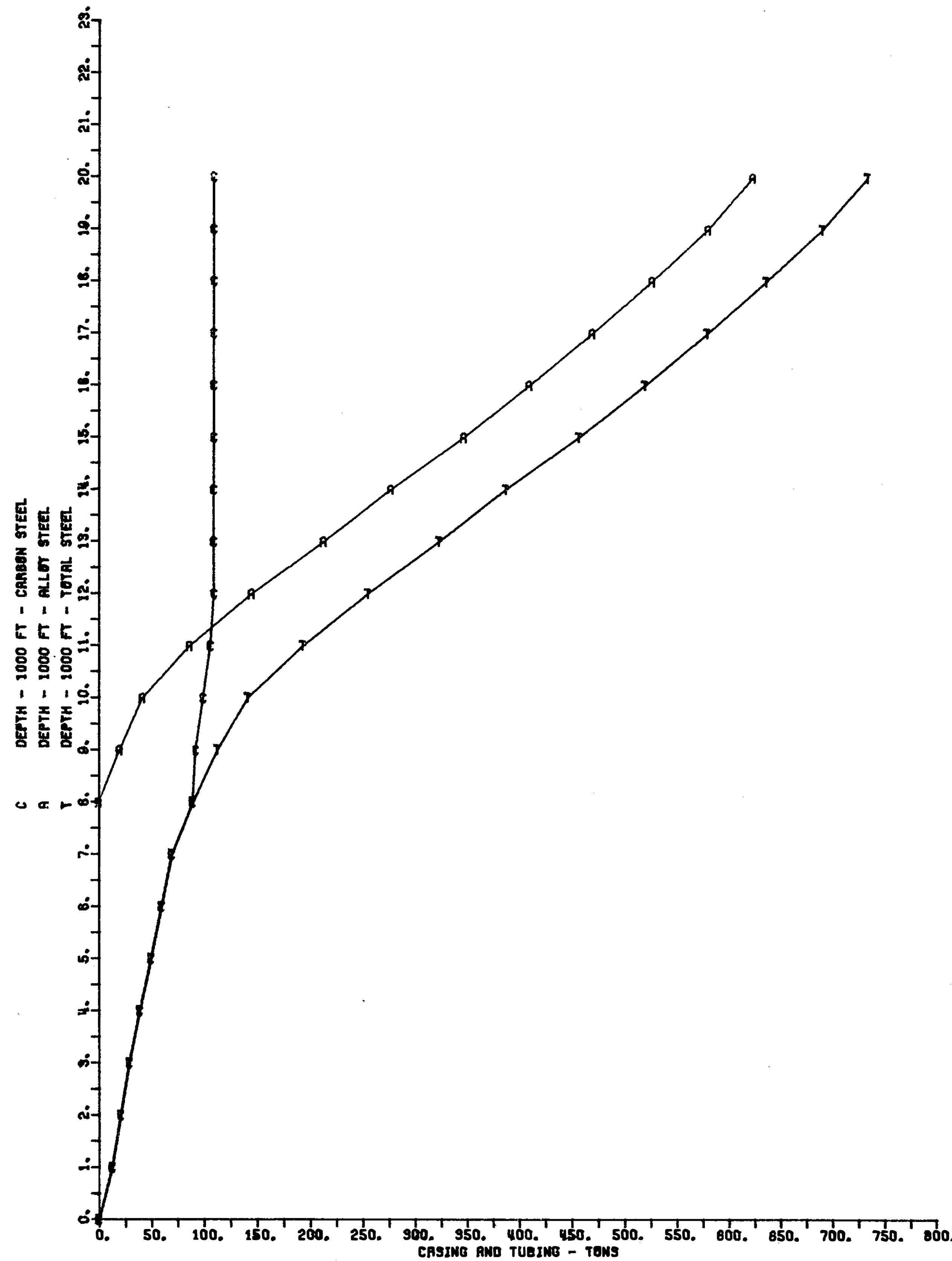


Figure 51. Producing Well - Region 5.

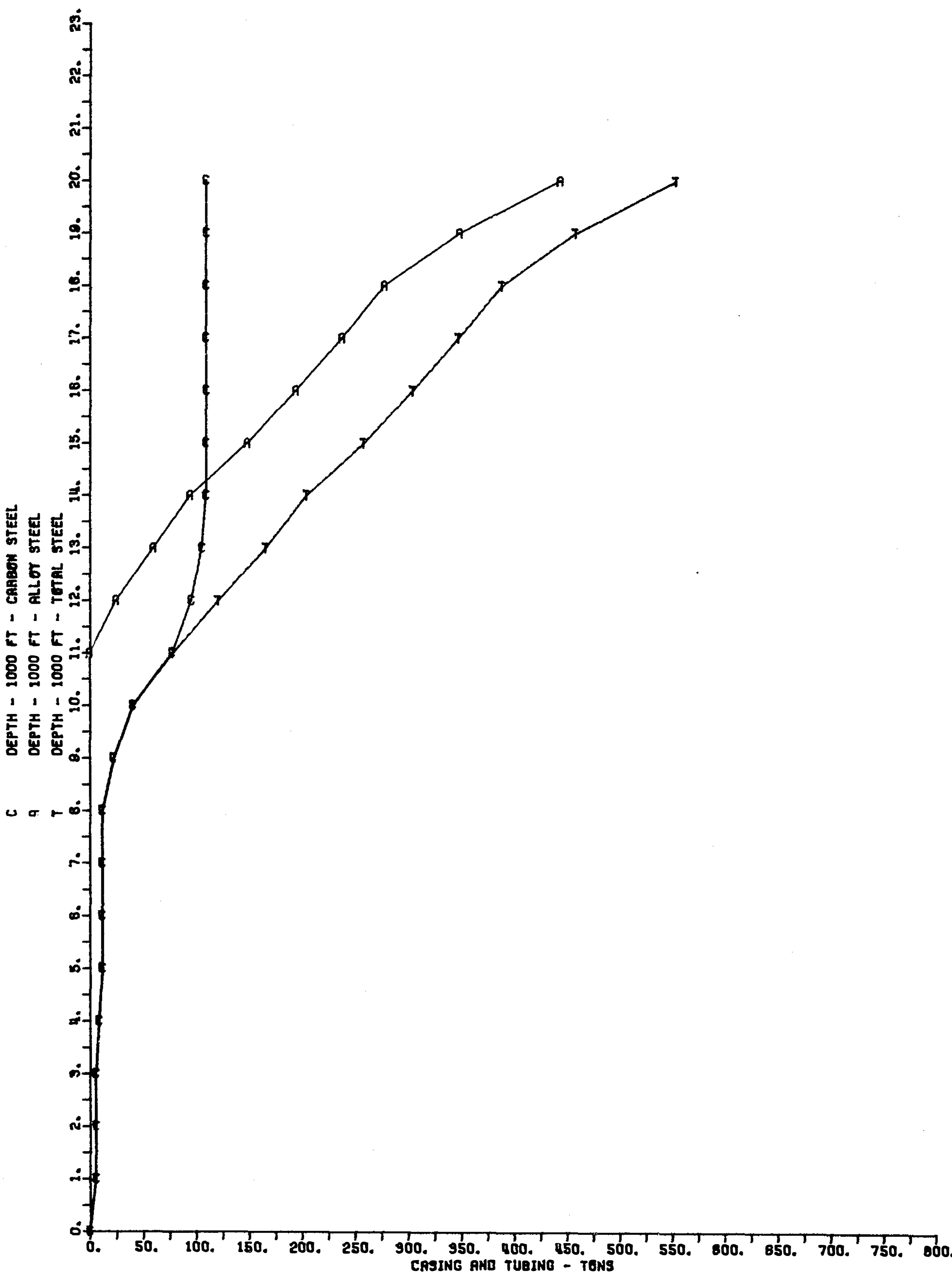


Figure 52. Dry Hole - Region 5.

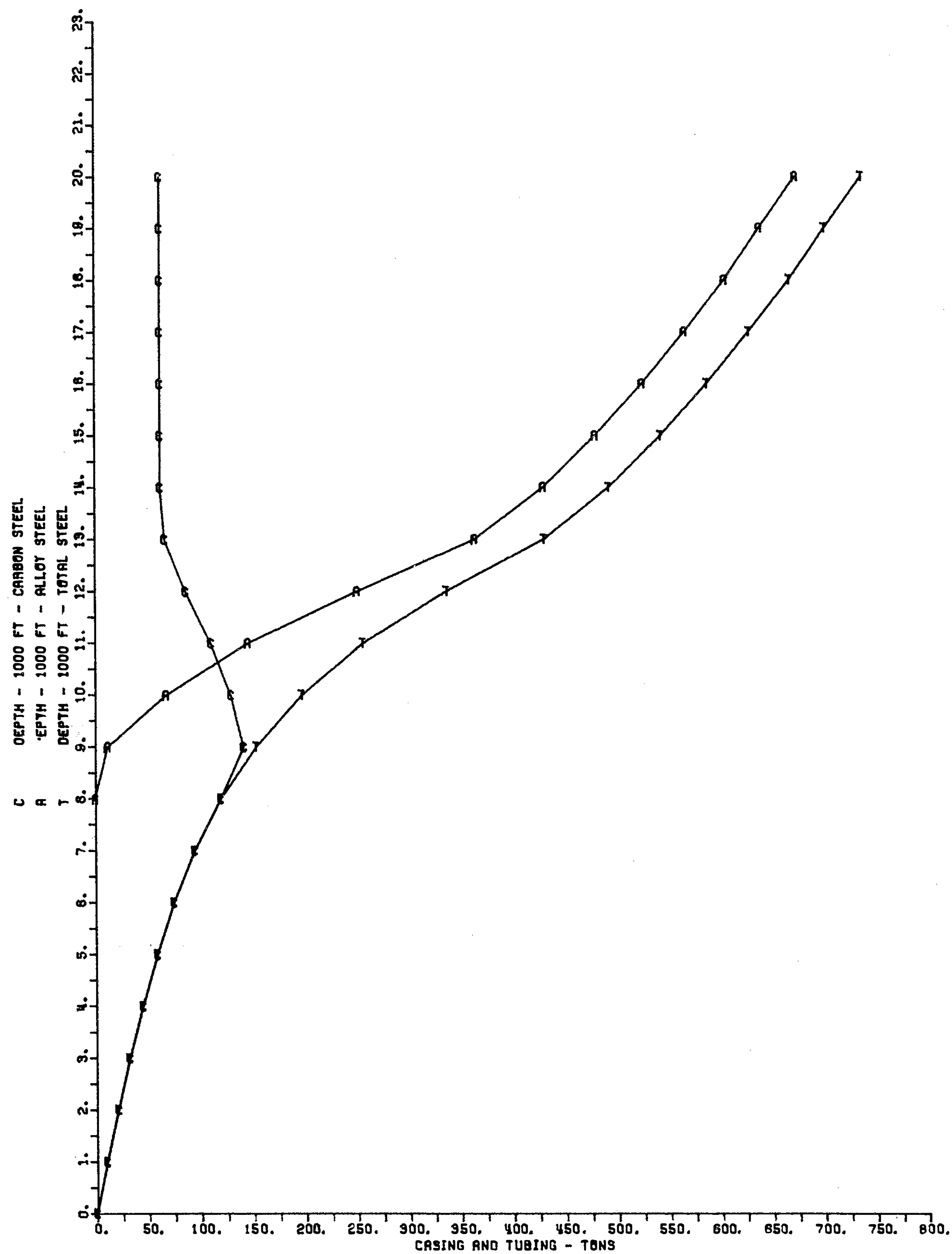


Figure 53. Producing Well - Region 6.

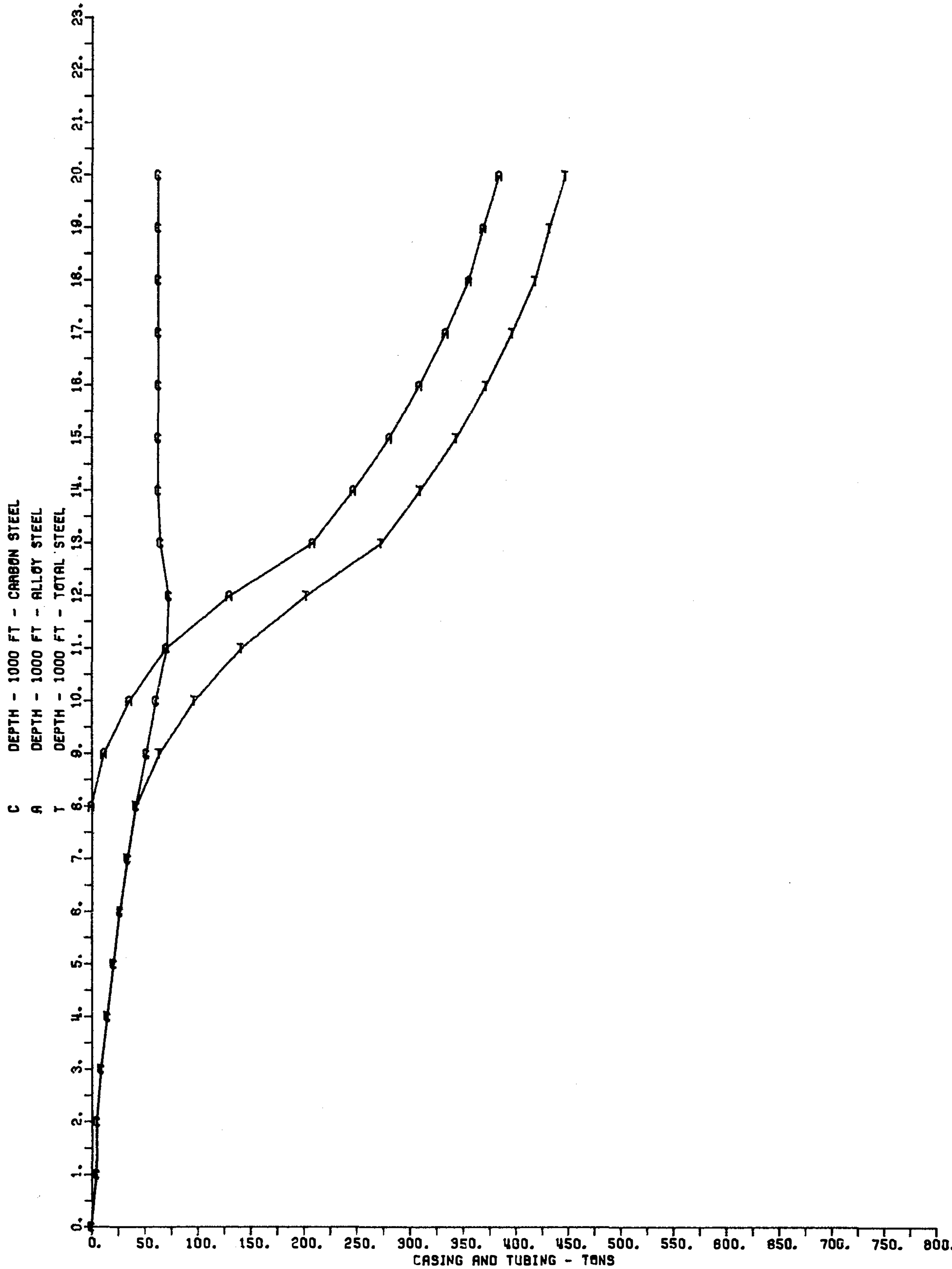


Figure 54. Dry Hole - Region 6.

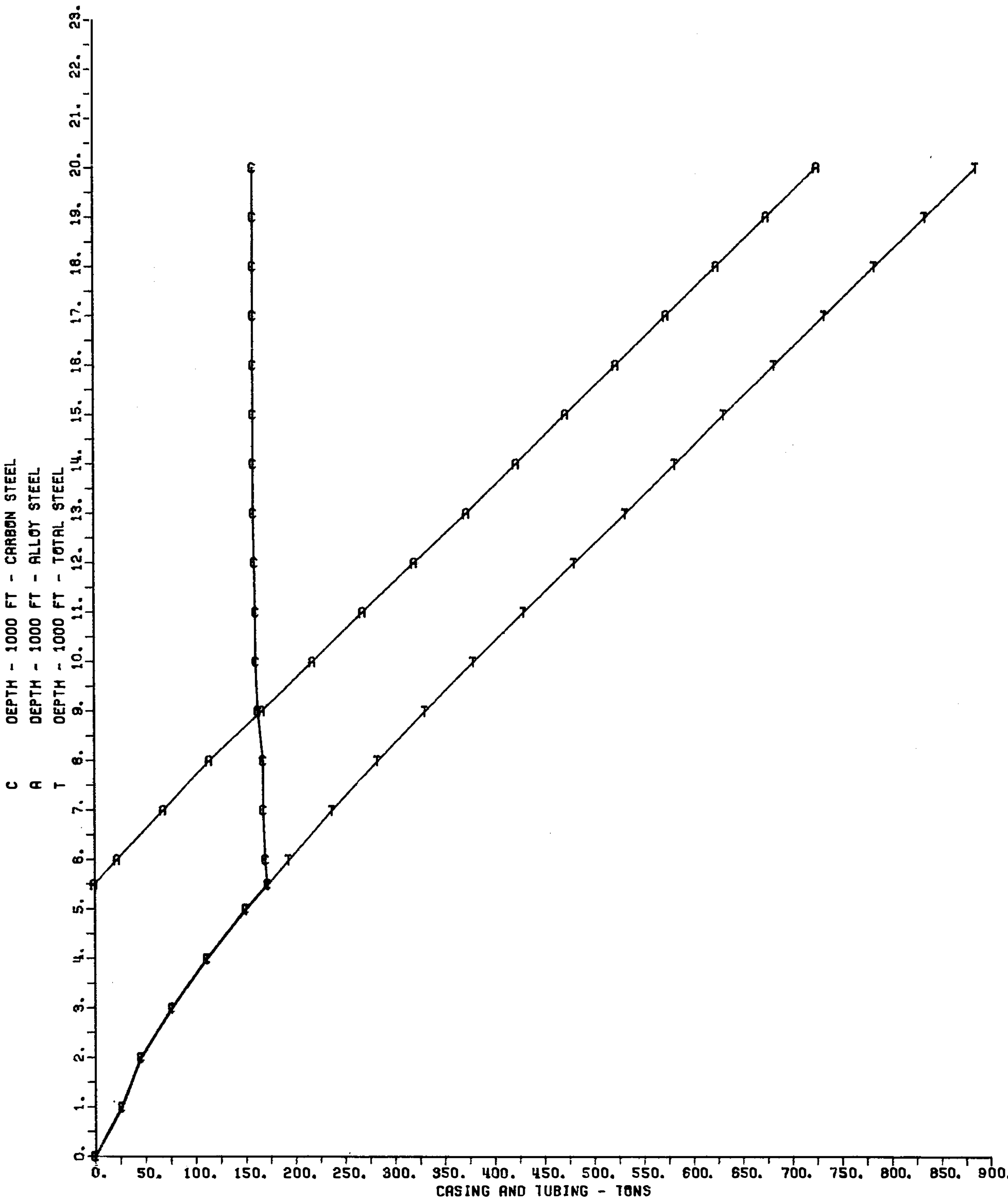


Figure 55. Producing Well - Region 6A.

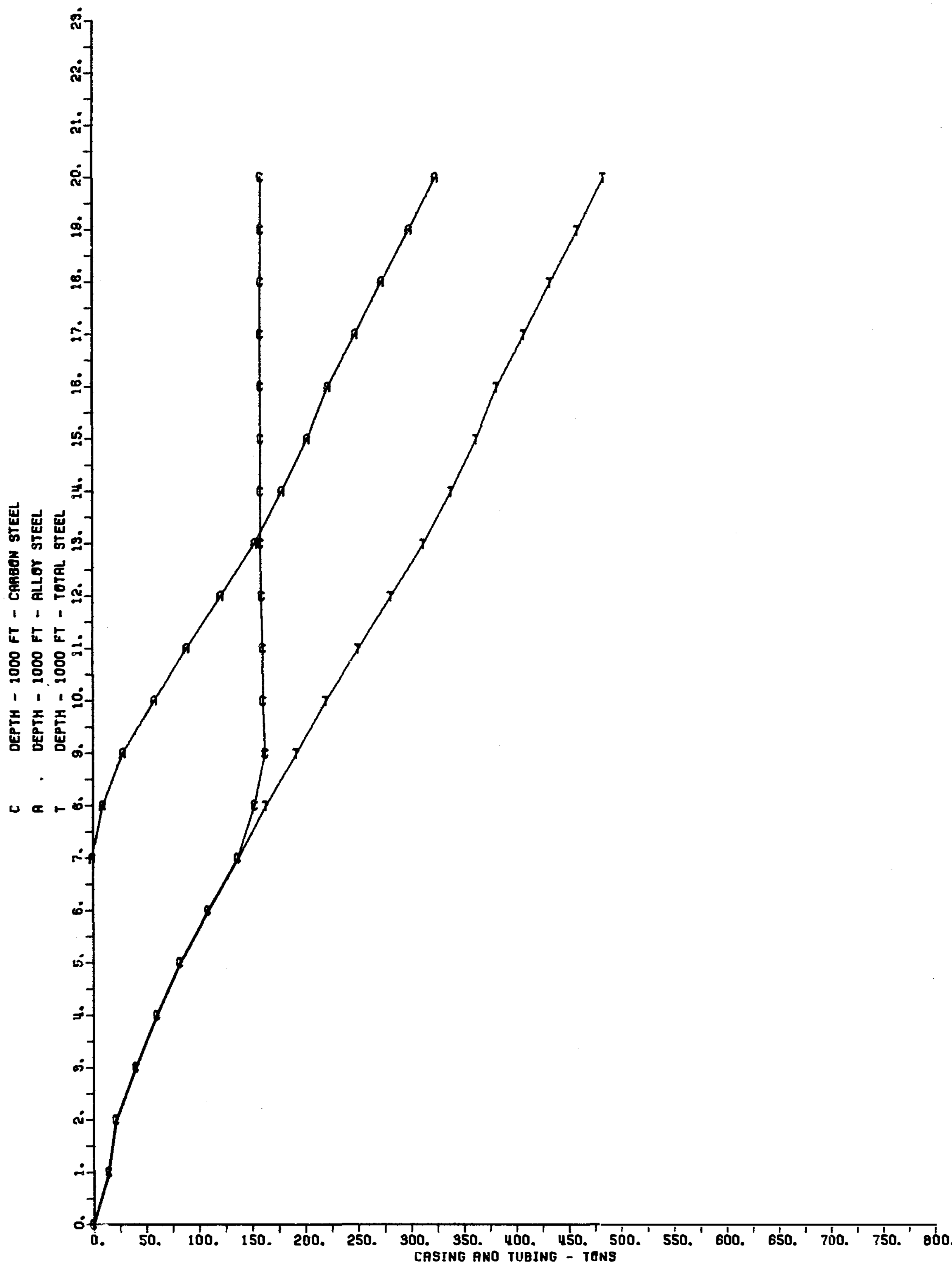


Figure 56. Dry Hole - Region 6A.

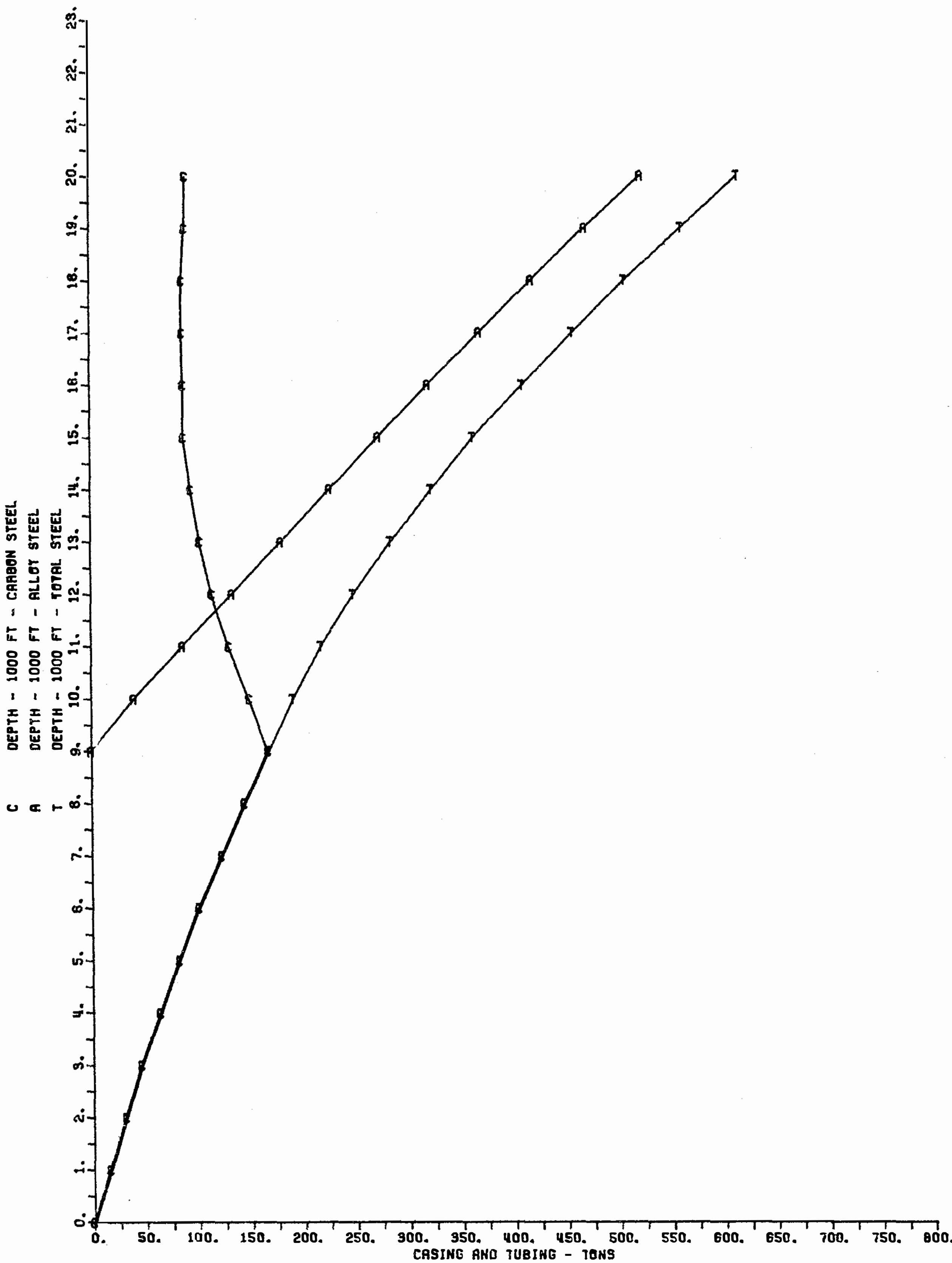


Figure 57. Producing Well - Region 7.

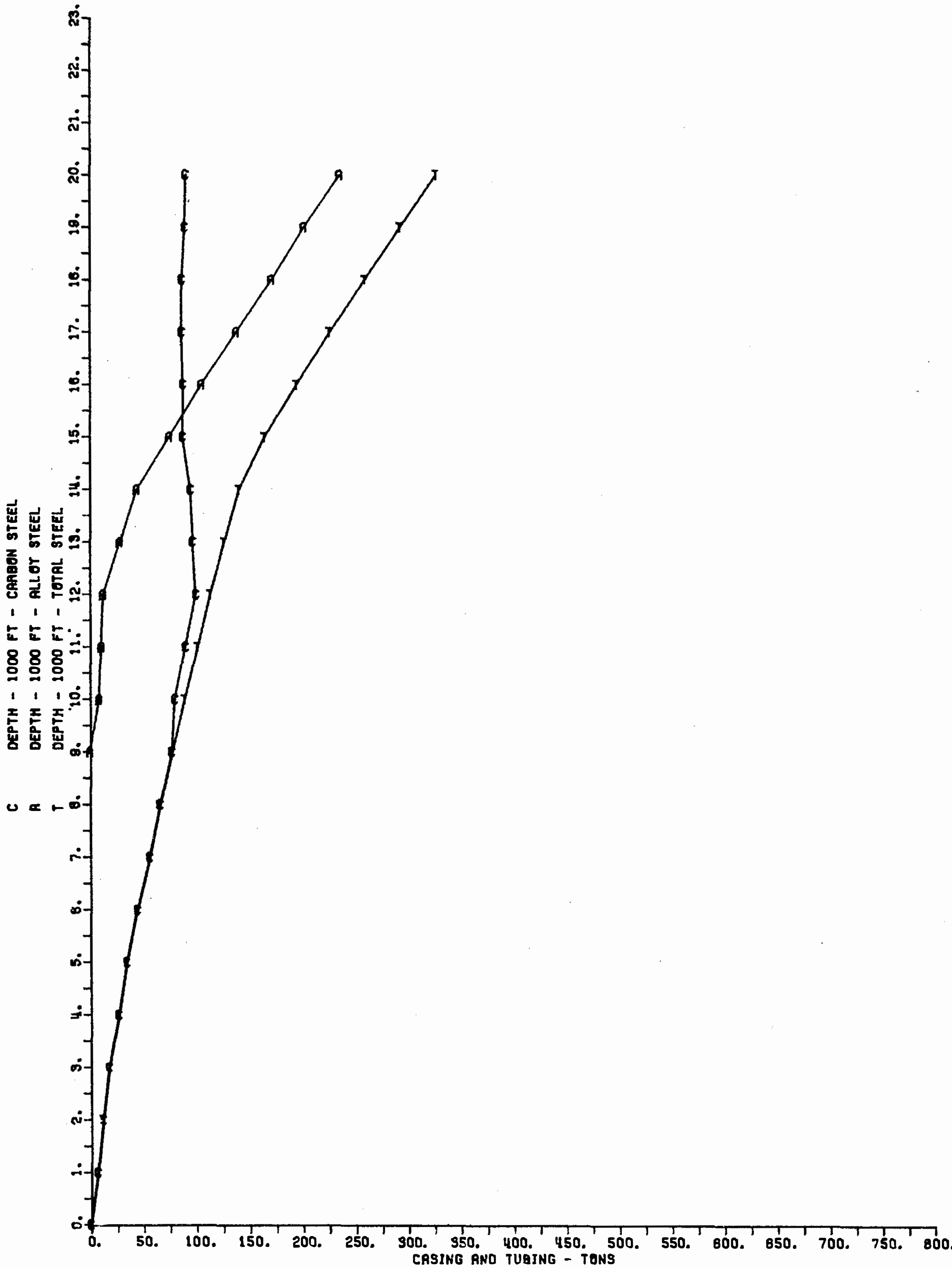


Figure 58. Dry Hole - Region 7.

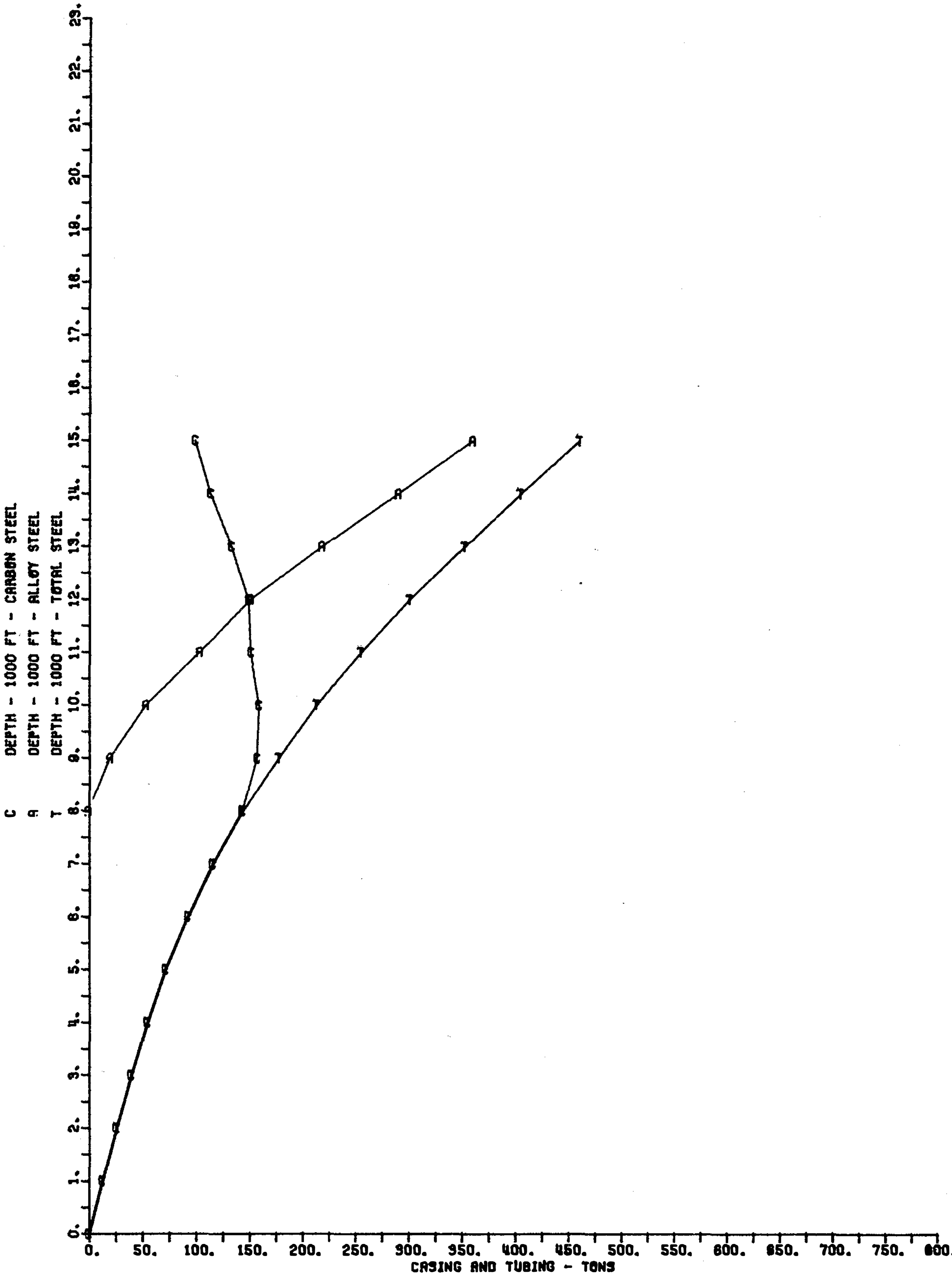


Figure 59. Producing Well - Region 8.

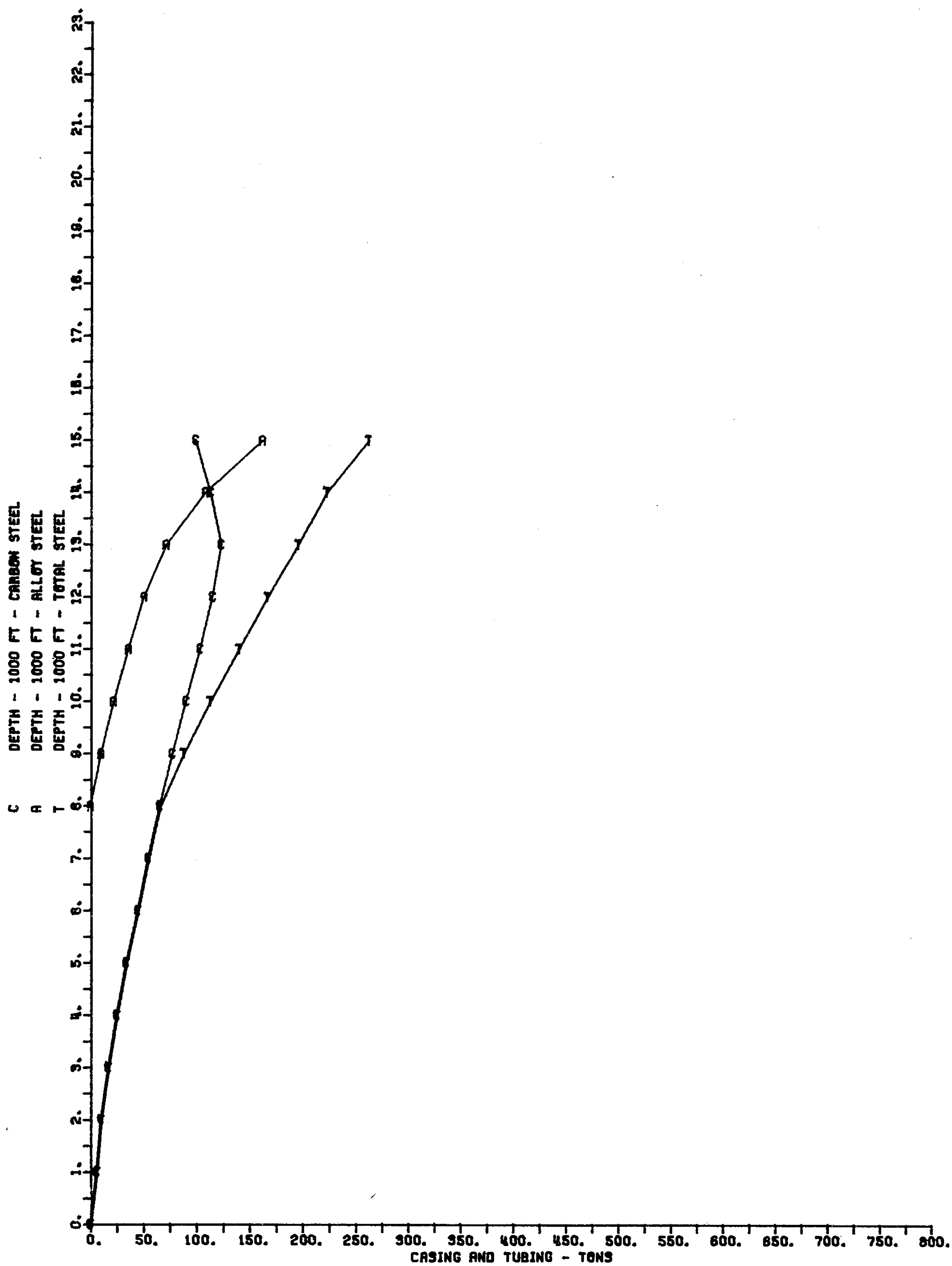


Figure 60. Dry Hole - Region 8.

APPENDIX F

Exploration and Drilling

TABLE 72

ROCK BIT USAGE BY DEPTH INTERVALS FOR EACH NPC REGION

	Depth (Feet)	Bits
Regions 1 and 1A		
North Slope	10,300 (Average)	21 (Average)
Anchorage–Kenai	11,740 (Average)	34 (Average)
Regions 2 and 2A		
Santa Barbara South	0 - 5,000	6
	5,000 - 10,000	17
	10,000 - 15,000	22
Bakersfield North	0 - 5,000	6
	5,000 - 10,000	15
	10,000 - 15,000	30
Region 3		
Casper, Wyoming–Vernal, Utah	0 - 5,000	8
	5,000 - 10,000	22
	10,000 - 15,000	14*
	15,000 - 20,000	28*
Craig, Colorado–Gillette, Wyoming	0 - 5,000	12
Cutbank, Montana–Willston, North Dakota	5,000 - 10,000	10
	10,000 - 15,000	18*
Region 4		
	0 - 5,000	2
	5,000 - 10,000	5-8*
	10,000 - 15,000	10-12*
	15,000 - 20,000	24-30*
	20,000 - 30,000	40-45*
Region 5		
Deep Delaware Basin	0 - 5,000	5-6
	5,000 - 10,000	4-5
	10,000 - 15,000	12-13*
	15,000 - 20,000	18-19*
West Texas (Other)	0 - 5,000	5-6
	5,000 - 10,000	6-7*
	10,000 - 15,000	8-9*
Central Texas	0 - 5,000	5-6
	5,000 - 10,000	5-6*
	10,000 - 15,000	4*
Region 6		
South Texas	0 - 5,000	3
	5,000 - 10,000	5
	10,000 - 15,000	6-10*
	15,000 - 20,000	15-20*
East Texas	0 - 5,000	3
	5,000 - 10,000	8-10*
	10,000 - 15,000	10-15*
	15,000 - 20,000	18-20*
North Louisiana–South Arkansas	0 - 5,000	3-4
	5,000 - 10,000	6-8*

*Most of these rock bits are compacts.

TABLE 72 (continued)

	Depth (Feet)	Bits
Region 7		
South Louisiana	0 - 5,000	3
	5,000 - 10,000	5
	10,000 - 15,000	7-10
	15,000 - 20,000	9-12*
South Mississippi—Alabama—Florida	0 - 5,000	3
	5,000 - 10,000	3-5*
	10,000 - 15,000	6-8*
	15,000 - 20,000	8-10*
North Mississippi	0 - 5,000	5-6*
Region 8 and 8A		
North Michigan	0 - 6,000	6-8*
Ohio	0 - 5,000	3-4*
West Virginia	0 - 5,000	2-5*
Pennsylvania	0 - 5,000	2-3
	5,000 - 10,000	6-10*
	10,000 - 15,000	25-30*
	15,000 - 20,000	34-36*

*Most of these rock bits are compacts.

TABLE 73

BENTONITE
(Tons)

Historical	NPC Region	Drilling Requirements	Other Industrial Requirements	Total Requirements	Domestic Production
1973*	1 & 2	30,475			
	3	63,825			
	4	70,725			
	5	70,150			
	6, 7 & 8	339, 825			
U.S. Total		**575,000**	**1,725,000**	**2,300,000**	**2,300,000***
Projected					
1974		632,500	1,897,500	2,530,000	2,530,000*
1975		695,750	2,087,250	2,783,000	2,783,000*
1976		765,325	2,295,975	3,061,300	3,061,300*

*Raw bentonite ore in place is in abundance. Limitations possibly on milling facilities only. Presently producing domestic total requirements.

TABLE 74

BARITE

(Tons)

Historical	NPC Region	Drilling Requirements	Other Industrial Requirements	Total Requirements	Domestic Production	Required Imports
1973*	1 & 2	62,540				
	3	130,980				
	4	145,140				
	5	143,960				
	6, 7 & 8	697,380				
U.S. Total		1,180,000	295,000	1,475,000	775,000	700,000*
Projected						
1974		1,298,000	324,500	1,622,500	852,500	770,000
1975		1,427,800	356,950	1,784,750	937,750	847,000
1976		1,570,580	392,645	1,963,225	1,031,525	931,700

*Presently require 700,000 tons imported crude ore to supply domestic requirements. See Table 81.

TABLE 75

LIGNOSULFONATES

(Tons)

Historical	NPC Region	Drilling Requirements	Other Industrial Requirements	Total Requirements	Domestic Production
1973*	1 & 2	1,855			
	3	3,885			
	4	4,305			
	5	4,270			
	6, 7 & 8	20,685			
U.S. Total		35,000	30,000	65,000	65,000*
Projected					
1974		38,500	33,000	71,500	71,500*
1975		42,350	36,300	78,650	78,650*
1976		46,585	39,930	86,515	86,515*

*Domestic production sufficient to cover requirements. No imports needed. This is a by-product of the paper industry and depends on a normal industry growth.

TABLE 76

THINNERS OTHER THAN LIGNOSULFONATES
(Tons)

Historical	NPC Region	Drilling Requirements
1973	1 & 2	1,166
	3	2,442
	4	2,706
	5	2,684
	6, 7 & 8	13,002
U.S. Total		22,000*
Projected		
1974		24,200*
1975		26,620*
1976		29,282*

*No imports necessary. Domestic production sufficient for needs. Other industrial requirements on lignite not available considering this material has widespread usage as a fuel.

TABLE 77

CAUSTIC SODA (SODIUM HYDROXIDE)
(Tons)

Historical	NPC Region	Drilling Requirements
1973	1 & 2	1,183
	3	2,509
	4	2,763
	5	2,752
	6, 7 & 8	13,293
U.S. Total		22,500*
Projected		
1974		24,800*
1975		27,300*
1976		29,900*

*No imports necessary. Domestic production sufficient for needs. Delivery time is increasing and caustic will fall short of domestic requirements if production is not increased. The soap industry is the largest single industry user of caustic soda.

TABLE 78

FLUID LOSS CONTROL AGENTS
(Tons)

Historical	NPC Region	Drilling Requirements	Other Industrial Requirements	Total Requirements	Domestic Production
1973	1 & 2	636			
	3	1,332			
	4	1,476			
	5	1,464			
	6, 7 & 8	7,092			
U.S. Total		**12,000**	**2,500**	**14,500**	**14,500***
Projected					
1974		13,200	2,600	15,800	15,800*
1975		14,520	2,600	17,120	17,120*
1976		15,972	2,600	18,572	18,572*

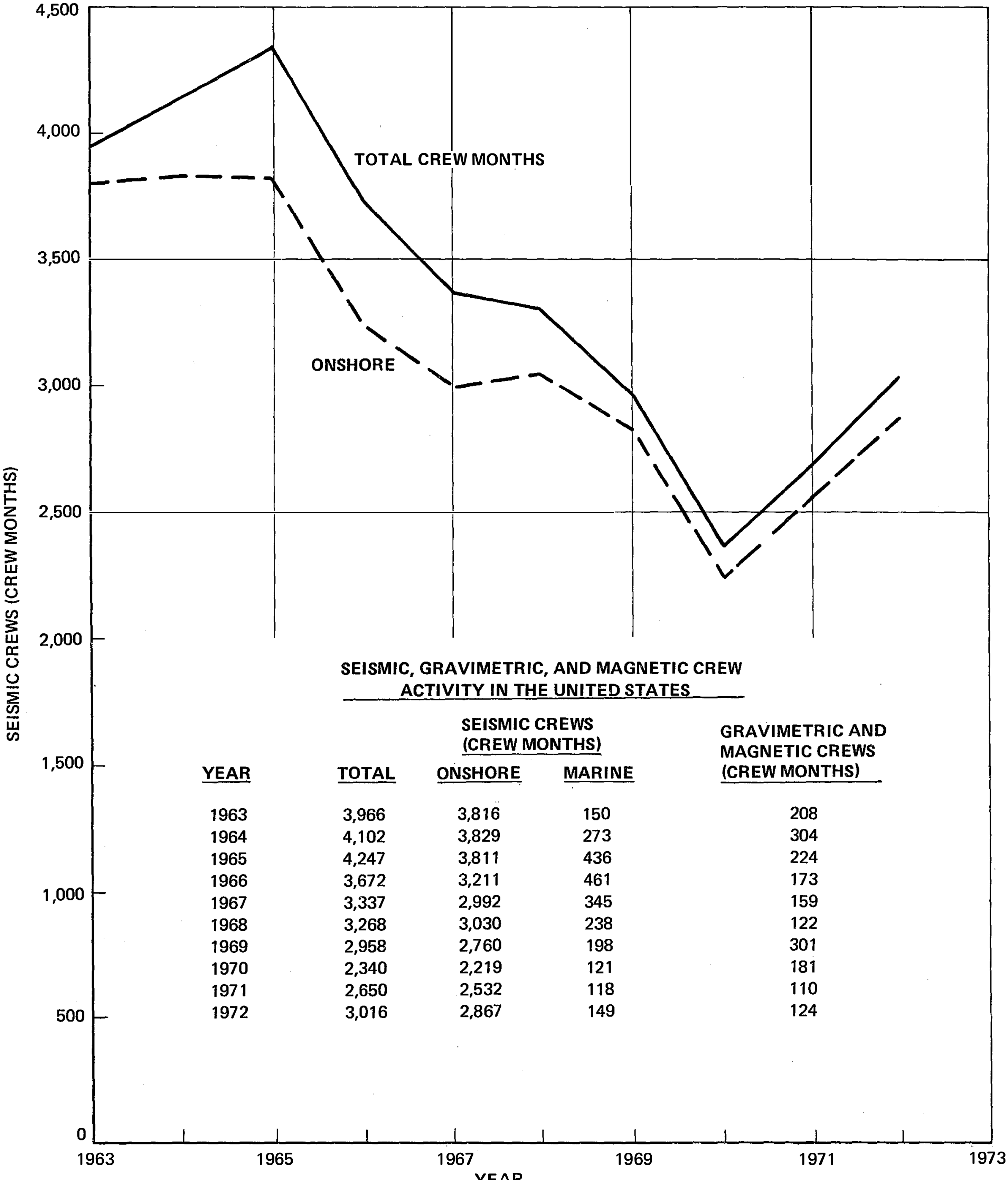
*No imports necessary. Domestic production sufficient for needs. This group includes Sodium Carboxy Methyl Cellulose (CMC), corn starch and minor uses of substitute products.

TABLE 79

IMPORTS OF BARITE—1973
(Tons)

Source	Imported Amounts	Estimated Reserves
Peru	197,948	1,000,000
Turkey	3,608	Unknown
Canada	50,000	200,000
Greece	56,018	1,000,000
Ireland	231,252	3,000,000
Mexico	132,815	1,000,000
Morocco	30,130	Unknown
Guatemala	164	Unknown
Sardinia	No Imports	Unknown
Total	**701,935**	**6,200,000**

Source: U.S. Department of Commerce, Tariff Schedules of the United States, Annotated (TSUSA), FT:T-IM-145, Washington, D.C.: Foreign Trade Division, Bureau of Census, 1973.



SEISMIC, GRAVIMETRIC, AND MAGNETIC CREW ACTIVITY IN THE UNITED STATES

	Seismic Crews (Crew Months)			
YEAR	TOTAL	ONSHORE	MARINE	GRAVIMETRIC AND MAGNETIC CREWS (CREW MONTHS)
1963	3,966	3,816	150	208
1964	4,102	3,829	273	304
1965	4,247	3,811	436	224
1966	3,672	3,211	461	173
1967	3,337	2,992	345	159
1968	3,268	3,030	238	122
1969	2,958	2,760	198	301
1970	2,340	2,219	121	181
1971	2,650	2,532	118	110
1972	3,016	2,867	149	124

Source: Society of Exploration Geophysicists.

Figure 61. Seismic Activity in the United States.

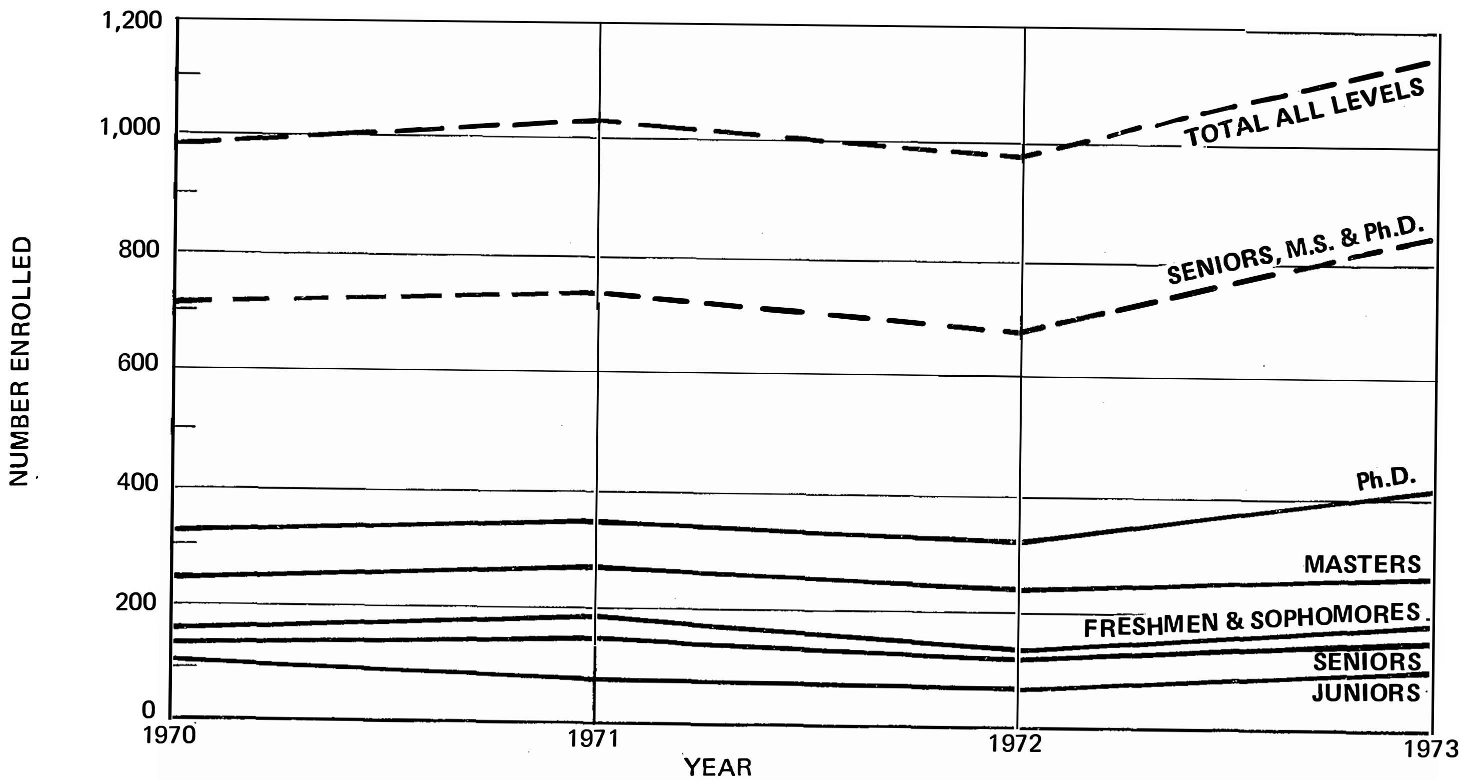
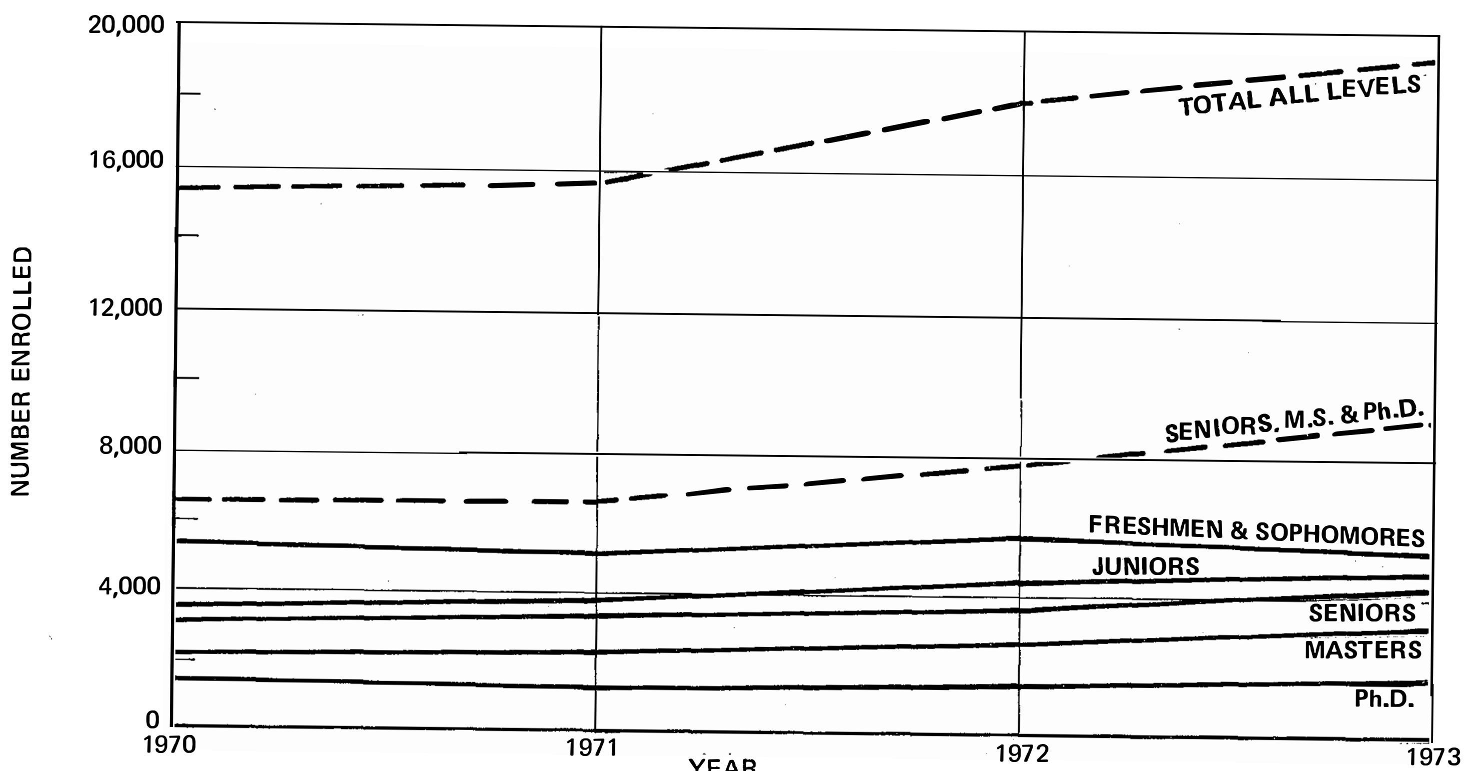


Figure 62. Geophysicists Enrollment in Degree Granting Institutions.

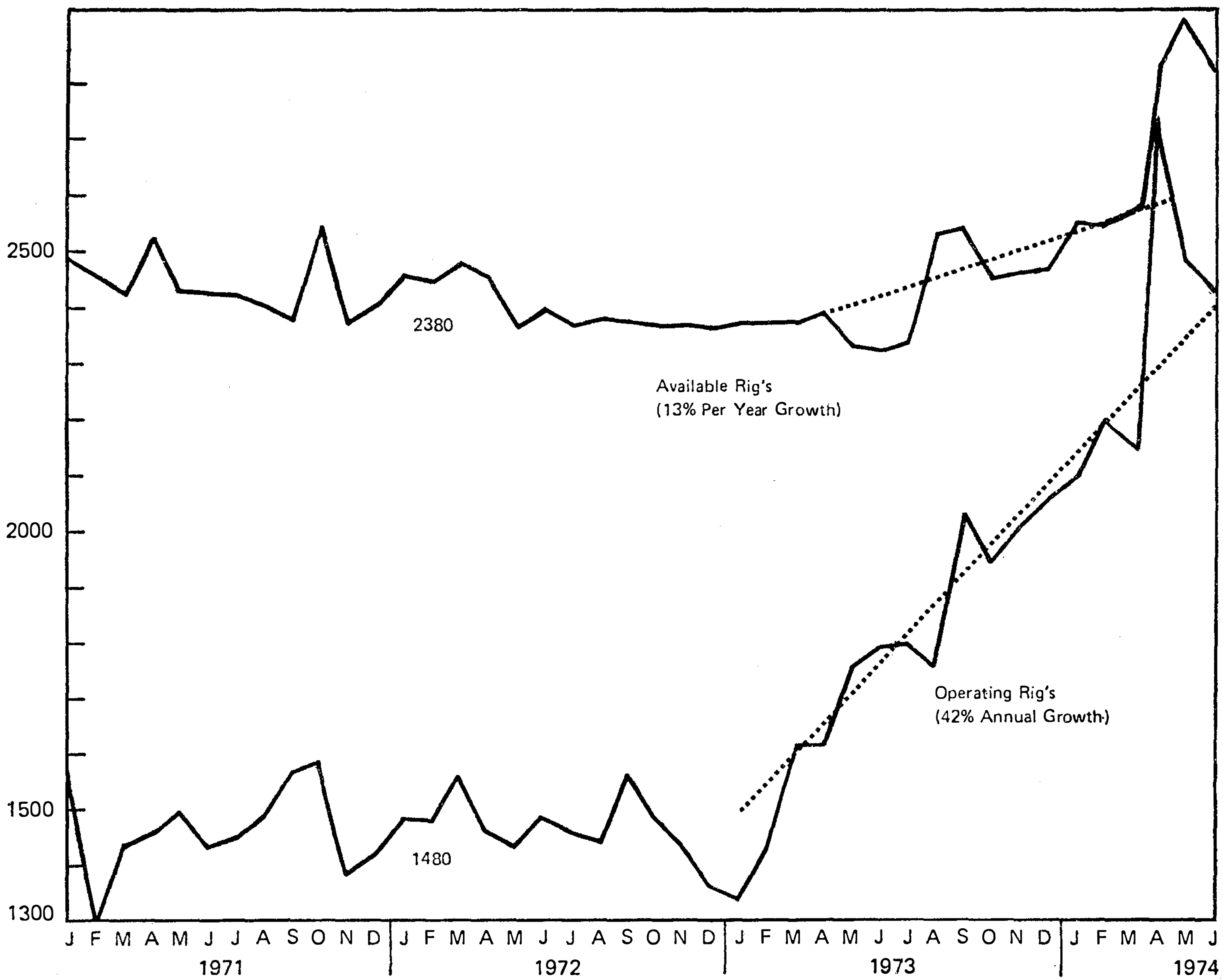


Source: Data from American Geological Institute.

Figure 63. Geologists Enrollment in Degree Granting Institutions (346 Schools).

APPENDIX G

Well Servicing



SOURCE: Guiberson Operations, Oilfield Products Division
(Based Upon Data from 60% of the Contractors Operating 76% of the Rigs)

Figure 64. U.S. Well Servicing and Workover Rig Activity.

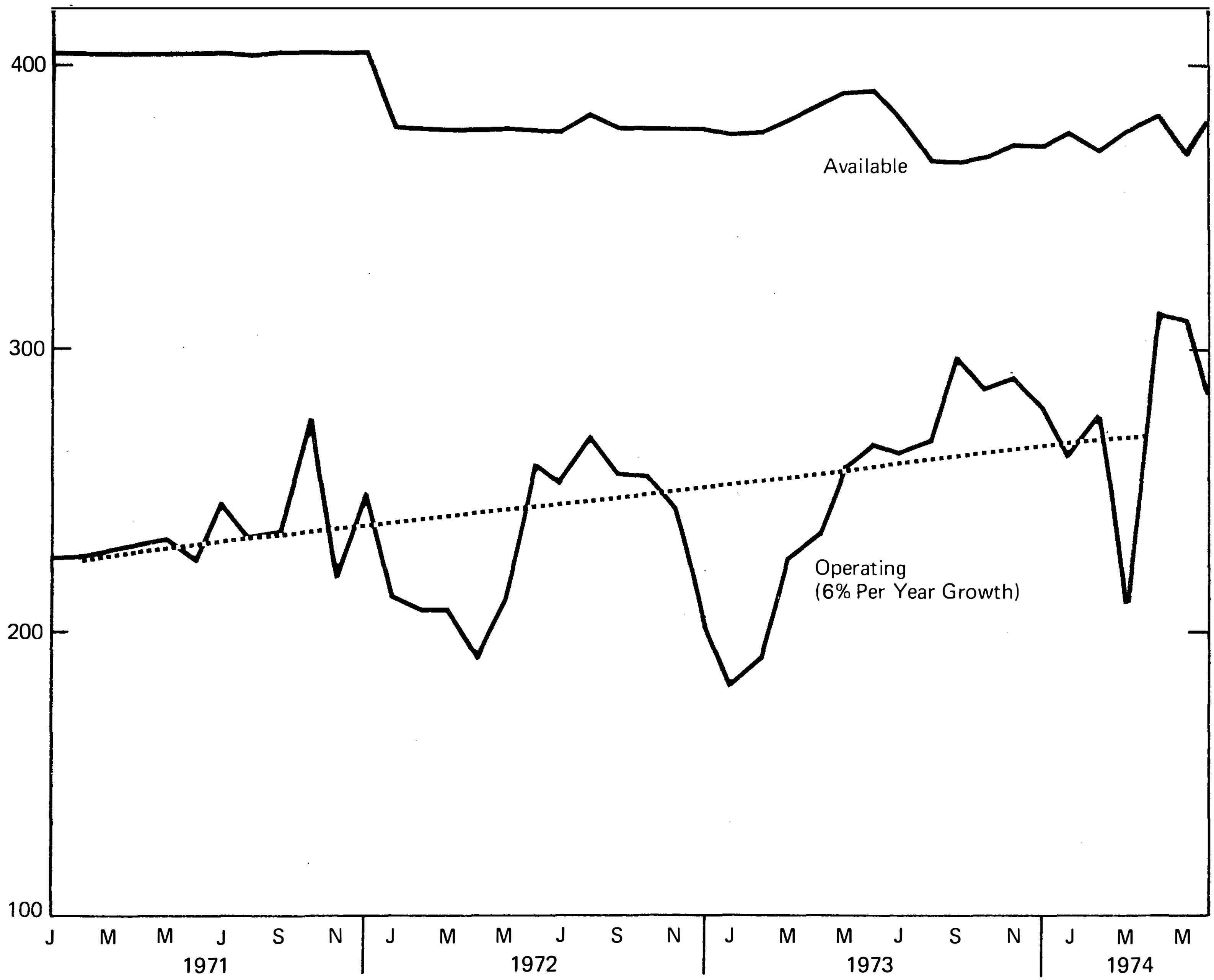


Figure 65. Well Servicing Rigs in the Eastern U.S.

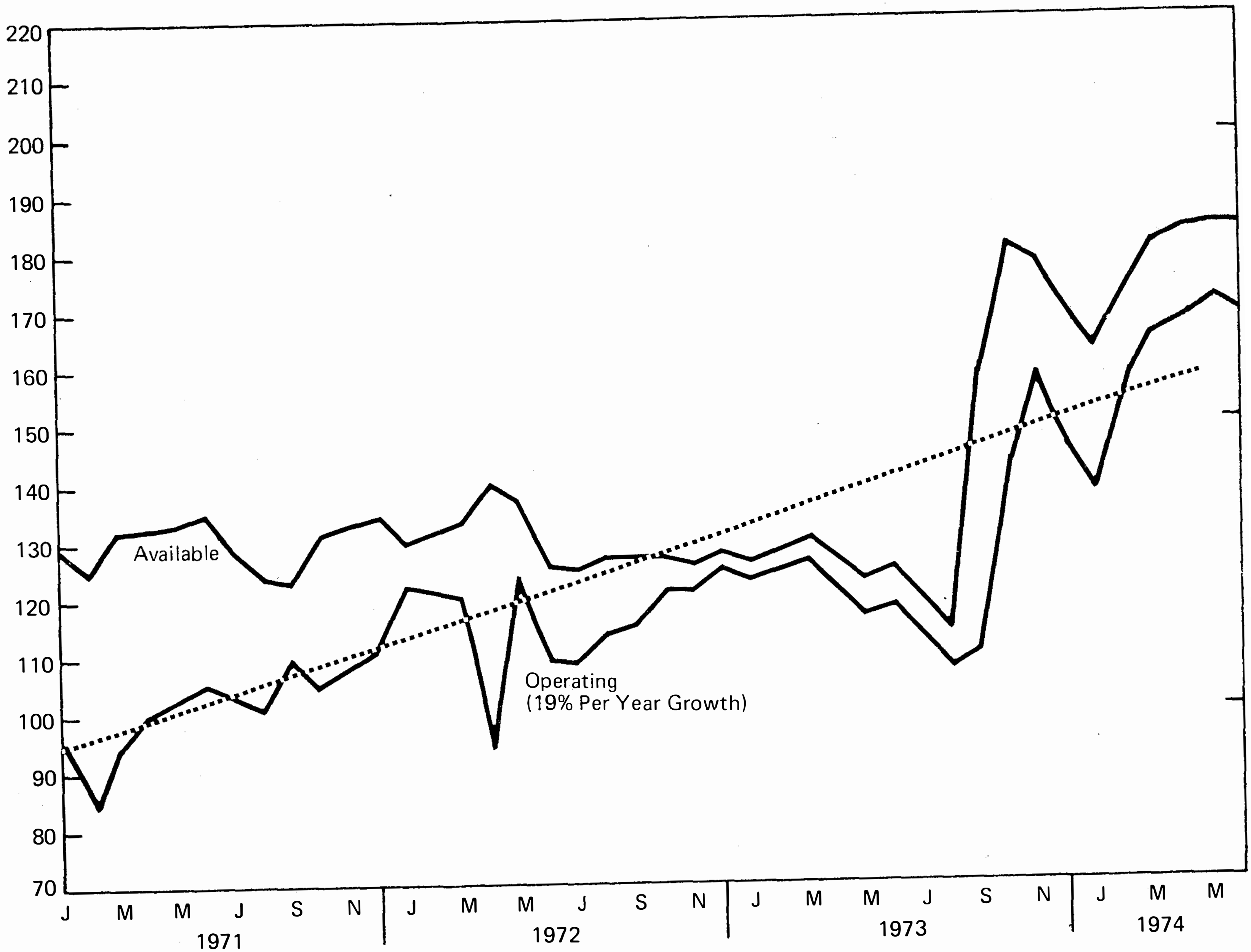


Figure 66. Well Servicing Rigs in South Louisiana.

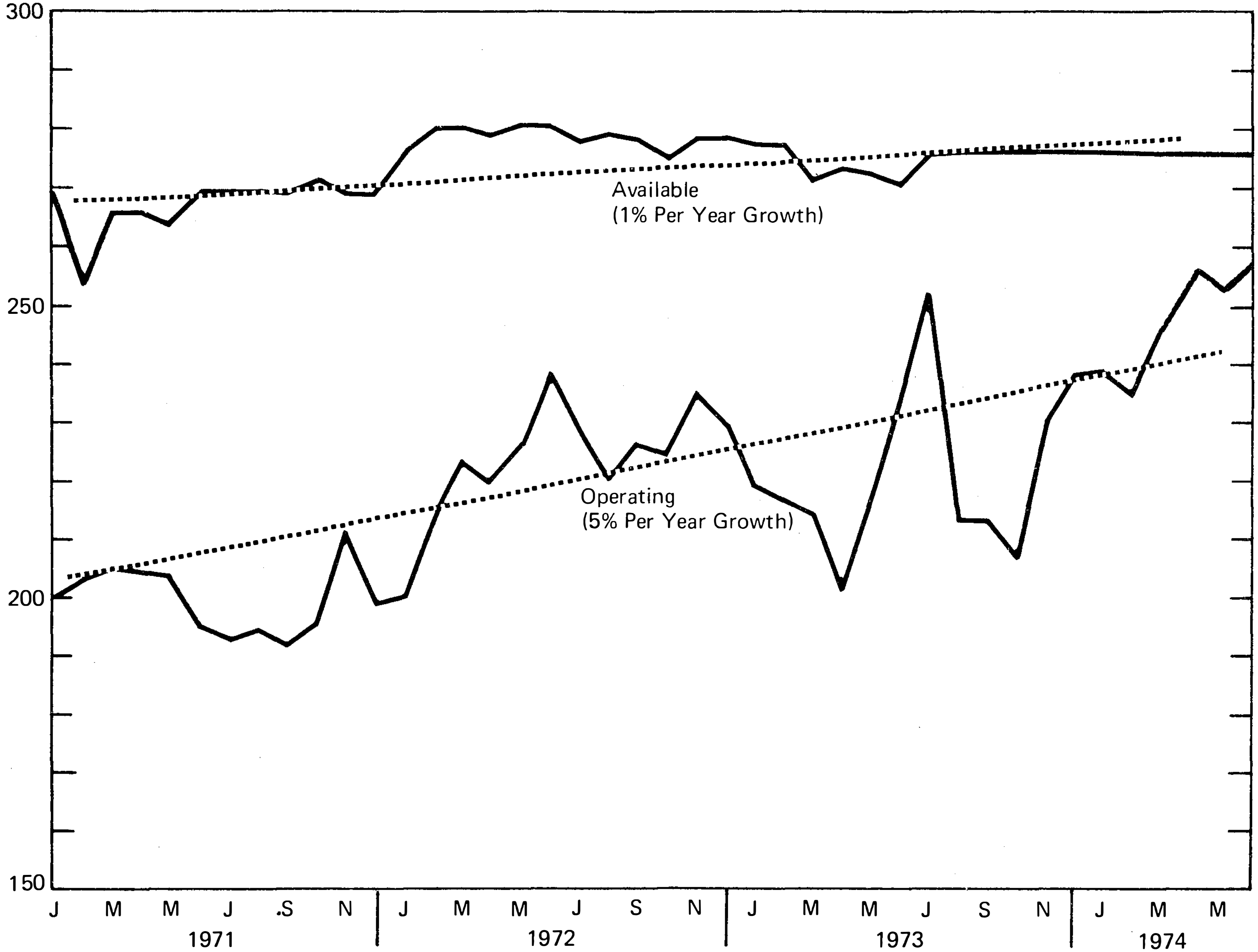


Figure 67. Well Servicing Rigs in the Texas Gulf Coast.

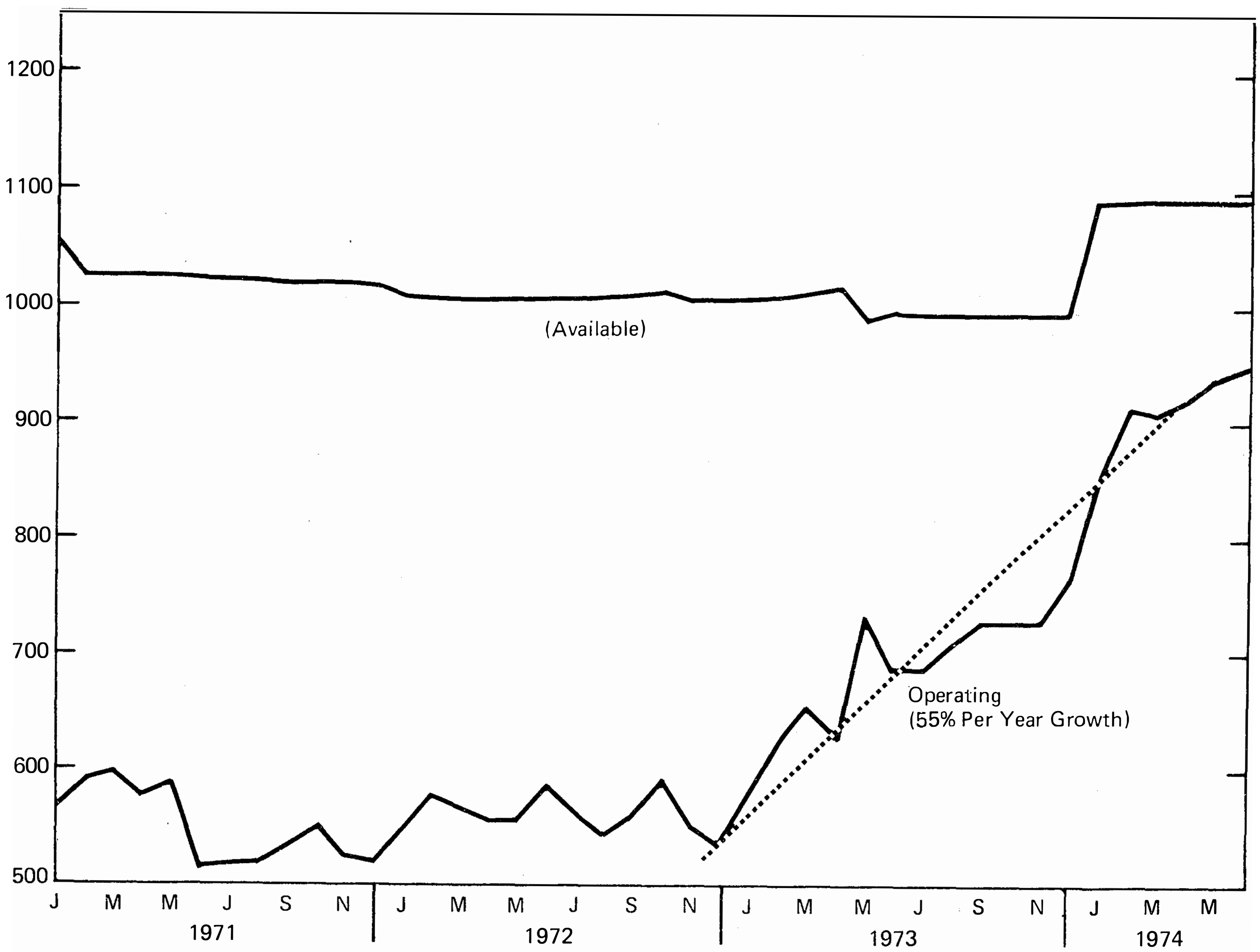


Figure 68. Well Servicing Rigs in the Central U.S.

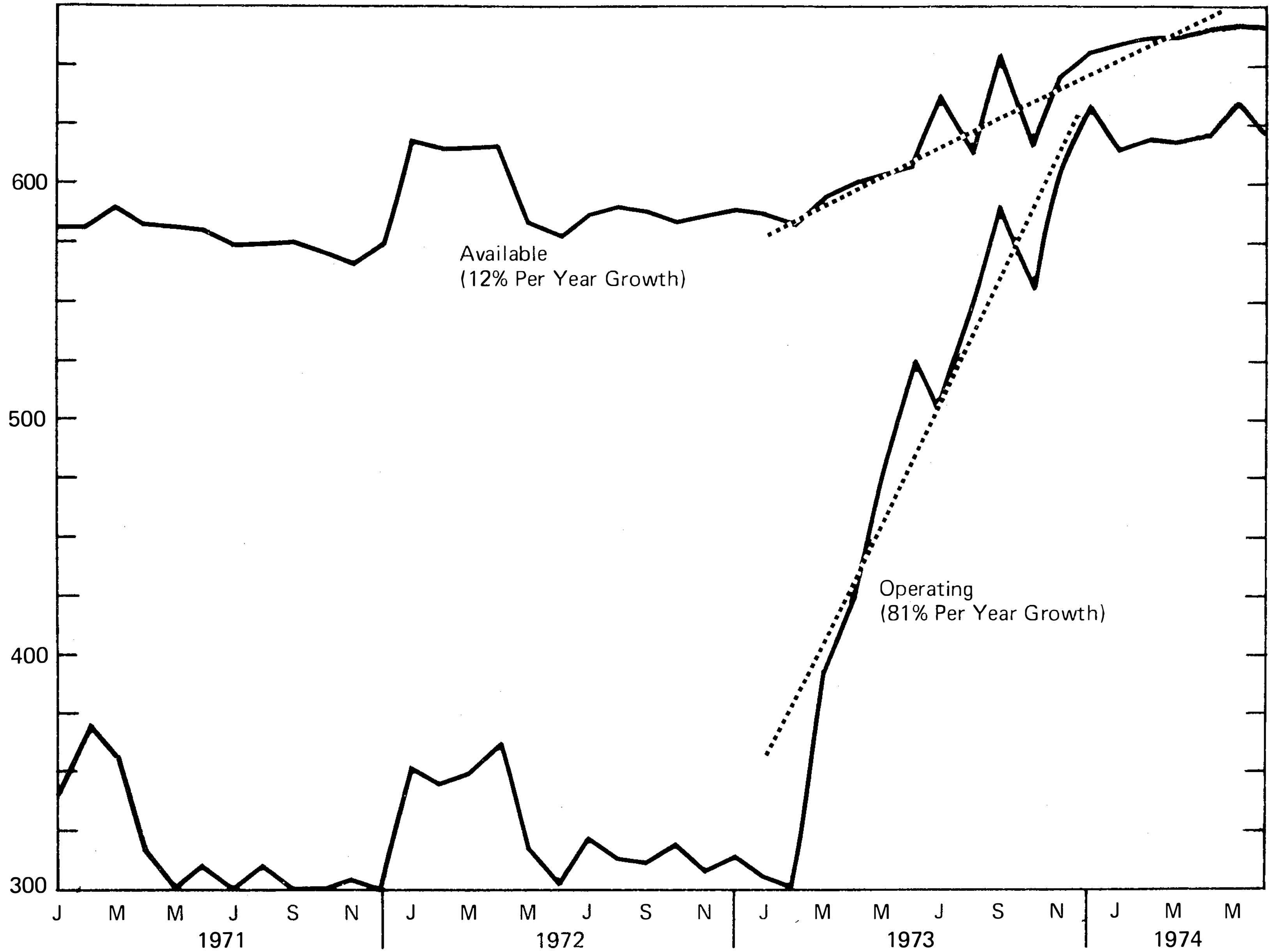


Figure 69. Well Servicing Rigs in the Western U.S.

APPENDIX H

Gas Processing Plants

TABLE 80

GAS PROCESSING—ALASKA (REGION 1)

Historical	Plant Capacity Annual Average	Plant Throughput (MMCF/D)	Percent Capacity	Liquid Products (MGAL/D)	(GAL/MCF)	Capacity Added: New Plants (MMCF/D)	Capacity Added: Expansions (MMCF/D)	Capacity Added: Total (MMCF/D)	Capacity Deleted (MMCF/D)	Net Capacity (MMCF/D)
1970	45.0	29.5	65.6	97.0	3.3	0	0	0	0	0
1971	45.0	34.2	76.0	106.7	3.1	0	0	0	0	0
1972	45.0	32.4	72.0	107.0	3.3	0	0	0	0	0
1973	52.5	49.0	93.3	128.3	2.6	0	15.0	15.0	0	15.0

TABLE 81

GAS PROCESSING—PACIFIC (REGION 2)

Historical	Plant Capacity Annual Average	Plant Throughput (MMCF/D)	Percent Capacity	Liquid Products (MGAL/D)	(GAL/MCF)	Capacity Added: New Plants (MMCF/D)	Capacity Added: Expansions (MMCF/D)	Capacity Added: Total (MMCF/D)	Capacity Deleted (MMCF/D)	Net Capacity (MMCF/D)
1970	2,008.8	1,126.3	56.1	2,239.5	2.0	23.0	4.0	27.0	72.6	(45.6)
1971	1,974.8	985.8	49.9	1,886.0	1.9	18.0	25.0	43.0	65.5	(22.5)
1972	1,871.5	884.7	47.3	1,584.2	1.8	0	0	0	184.0	(184.0)
1973	1,733.3	792.9	45.8	1,366.2	1.7	0	0	0	92.5	(92.5)

TABLE 82

GAS PROCESSING—ROCKY MOUNTAINS (REGION 3)

Historical	Plant Capacity Annual Average	Plant Throughput (MMCF/D)	Percent Capacity	Liquid Products (MGAL/D)	(GAL/MCF)	Capacity Added: New Plants (MMCF/D)	Capacity Added: Expansions (MMCF/D)	Capacity Added: Total (MMCF/D)	Capacity Deleted (MMCF/D)	Net Capacity (MMCF/D)
1970	3,479.0	2,743.5	78.9	3,526.3	1.3	263.0	4.5	267.5	116.1	151.4
1971	3,561.8	2,815.5	79.0	4,088.1	1.5	28.0	66.0	94.0	52.0	42.0
1972	3,594.8	2,896.2	80.6	3,968.8	1.4	25.6	31.4	57.0	34.0	23.0
1973	3,600.0	2,855.2	79.3	4,014.5	1.4	85.0	8.8	93.8	107.2	(13.4)

TABLE 83

GAS PROCESSING – MID-CONTINENT (REGION 4)

Historical	Plant Capacity Annual Average	Plant Throughput (MMCF/D)	Percent Capacity	Liquid Products (MGAL/D)	(GAL/MCF)	Capacity Added (MMCF/D) New Plants	Expansions	Total	Capacity Deleted (MMCF/D)	Net Capacity (MMCF/D)
1970	13,910.5	11,034.6	79.3	13,193.6	1.2	399.0	162.2	561.2	503.7	57.5
1971	13,976.5	11,018.3	78.8	13,453.4	1.2	73.0	200.0	273.0	198.5	74.5
1972	14,036.2	10,883.8	77.6	13,528.3	1.2	89.0	148.5	237.5	192.5	45.0
1973	14,045.1	10,711.5	76.3	13,179.9	1.2	111.5	269.0	360.5	407.8	(27.3)

TABLE 84

GAS PROCESSING–WEST TEXAS, SOUTHEAST NEW MEXICO (REGION 5)

Historical	Plant Capacity Annual Average	Plant Throughput (MMCF/D)	Percent Capacity	Liquid Products (MGAL/D)	(GAL/MCF)	Capacity Added (MMCF/D) New Plants	Expansions	Total	Capacity Deleted (MMCF/D)	Net Capacity (MMCF/D)
1970	8,702.7	6,899.0	79.3	15,437.8	2.3	178.0	229.0	407.0	309.2	97.8
1971	8,749.3	6,780.2	77.5	16,348.6	2.4	94.0	170.3	264.3	269.0	(4.7)
1972	8,818.3	6,600.3	74.8	17,830.9	2.7	277.8	36.8	314.6	172.0	142.6
1973	8,987.9	6,397.9	71.2	17,830.1	2.8	71.0	444.0	515.0	318.3	196.7

TABLE 85

GAS PROCESSING–EAST TEXAS, SOUTH ARKANSAS AND NORTH LOUISIANA (REGION 6)

Historical	Plant Capacity Annual Average	Plant Throughput (MMCF/D)	Percent Capacity	Liquid Products (MGAL/D)	(GAL/MCF)	Capacity Added (MMCF/D) New Plants	Expansions	Total	Capacity Deleted (MMCF/D)	Net Capacity (MMCF/D)
1970	21,590.4	15,351.6	71.1	19,632.4	1.3	292.0	65.0	357.0	804.9	(447.9)
1971	21,109.0	14,516.4	68.8	20,064.2	1.4	14.0	386.0	400.0	1,076.9	(676.9)
1972	20,576.5	14,122.9	68.6	20,386.0	1.4	331.0	176.8	507.8	888.4	(380.6)
1973	20,674.0	13,378.7	64.7	19,343.9	1.4	133.1	1,325.2	1,458.3	554.1	904.2

TABLE 86
GAS PROCESSING—SOUTHEAST (REGION 7)

Historical	Plant Capacity Annual Average	Plant Throughput (MMCF/D)	Percent Capacity	Liquid Products (MGAL/D)	(GAL/MCF)	Capacity Added (MMCF/D) New Plants	Expansions	Total	Capacity Deleted (MMCF/D)	Net Capacity (MMCF/D)
1970	20,810.0	19,554.2	94.0	18,509.8	1.0	2,123.5	1,728.0	3,851.5	607.2	3,244.3
1971	22,361.5	20,308.0	90.8	17,548.5	0.9	319.0	689.0	1,008.0	661.0	347.0
1972	22,498.2	19,106.3	84.9	17,236.1	0.9	320.0	3.5	323.5	396.3	(72.8)
1973	22,753.1	20,135.7	88.5	17,001.3	0.8	990.3	24.0	1,014.3	431.6	582.7

TABLE 87
GAS PROCESSING—NORTHEAST (REGION 8)

Historical	Plant Capacity Annual Average	Plant Throughput (MMCF/D)	Percent Capacity	Liquid Products (MGAL/D)	(GAL/MCF)	Capacity Added (MMCF/D) New Plants	Expansions	Total	Capacity Deleted (MMCF/D)	Net Capacity (MMCF/D)
1970	2,779.7	2,401.1	86.4	2,797.0	1.2	18.8	8.0	26.8	96.0	(69.2)
1971	2,704.9	2.334.0	86.3	2,655.4	1.1	0	3.0	3.0	83.4	(80.4)
1972	2,374.4	1,714.1	72.2	2,579.1	1.5	32.4	0	32.4	613.0	(580.6)
1973	2,032.0	1,589.9	78.2	2,452.1	1.5	0	7.0	7.0	35.2	(28.2)

TABLE 88
NEW GAS PROCESSING PLANTS IN 1970 – CAPACITY END-OF-YEAR
(Million Cubic Feet Per Day)

(MMCF/D)	Region 1 #	Region 1 Capacity	Region 2 #	Region 2 Capacity	Region 3 #	Region 3 Capacity	Region 4 #	Region 4 Capacity	Region 5 #	Region 5 Capacity	Region 6 #	Region 6 Capacity	Region 7 #	Region 7 Capacity	Region 8 #	Region 8 Capacity	Total U.S. #	Total U.S. Capacity	Average Plant Size
0-20	–	–	2	23.0	10	72.0	1	10.0	6	40.2	3	36.0	9	121.5	1	18.8	32	321.5	10.0
21-50	1	40.0	–	–	4	126.0	2	55.0	2	65.0	2	68.0	4	132.5	–	–	15	486.5	32.4
51-100	–	–	–	–	1	65.0	1	84.0	1	75.0	1	75.0	1	100.0	–	–	5	399.0	79.8
Over 100	–	–	–	–	–	–	1	250.0	–	–	1	150.0	2	1,800.0	–	–	4	2,200.0	550.0
Total	**1**	**40.0**	**2**	**23.0**	**15**	**263.0**	**5**	**399.0**	**9**	**180.2**	**7**	**329.0**	**16**	**2,154.0**	**1**	**18.8**	**56**	**3,407.0**	**60.8**

TABLE 89

NEW GAS PROCESSING PLANTS IN 1971 – CAPACITY END-OF-YEAR
(Million Cubic Feet Per Day)

	Region 1		Region 2		Region 3		Region 4		Region 5		Region 6		Region 7		Region 8		Total U.S.		Average Plant
(MMCF/D)	#	Capacity	#	Capacity	#	Capacity	#	Capacity	#	Capacity	#	Capacity	#	Capacity	#	Capacity	#	Capacity	Size
0-20	–	–	2	30.0	2	28.0	2	17.0	5	64.0	3	42.0	2	13.0	–	–	16	194.0	12.1
21-50	–	–	1	55.0	–	–	–	–	1	30.0	3	98.0	–	–	–	–	5	183.0	36.6
51-100	–	–	–	–	–	–	1	56.0	–	–	–	–	3	181.0	–	–	4	237.0	59.3
Over 100	–	–	–	–	–	–	–	–	–	–	–	–	1	125.0	–	–	1	125.0	125.0
Total	–	–	3	85.0	2	28.0	3	73.0	6	94.0	6	140.0	6	319.0	–	–	26	739.0	28.4

TABLE 90

NEW GAS PROCESSING PLANTS IN 1972 – CAPACITY END-OF-YEAR
(Million Cubic Feet Per Day)

	Region 1		Region 2		Region 3		Region 4		Region 5		Region 6		Region 7		Region 8		Total U.S.		Average Plant
(MMCF/D)	#	Capacity	#	Capacity	#	Capacity	#	Capacity	#	Capacity	#	Capacity	#	Capacity	#	Capacity	#	Capacity	Size
0-20	–	–	–	–	1	5.0	2	17.0	6	62.8	2	13.0	1	10.0	2	32.4	14	140.2	10.0
21-50	–	–	–	–	1	20.6	2	72.0	3	115.0	4	108.0	1	50.0	–	–	11	365.6	33.2
51-100	–	–	–	–	–	–	–	–	1	100.0	1	60.0	3	260.0	–	–	5	420.0	84.0
Over 100	–	–	–	–	–	–	–	–	–	–	1	150.0	–	–	–	–	1	150.0	150.0
Total	–	–	–	–	2	25.6	4	89.0	10	277.8	8	331.0	5	320.0	2	32.4	31	1,075.8	34.7

TABLE 91

NEW GAS PROCESSING PLANTS IN 1973 – CAPACITY END-OF-YEAR
(Million Cubic Feet Per Day)

	Region 1		Region 2		Region 3		Region 4		Region 5		Region 6		Region 7		Region 8		Total U.S.		Average Plant
(MMCF/D)	#	Capacity	#	Capacity	#	Capacity	#	Capacity	#	Capacity	#	Capacity	#	Capacity	#	Capacity	#	Capacity	Size
0-20	–	–	–	–	9	85.0	3	31.5	2	16.0	2	28.1	3	30.3	–	–	19	190.9	10.0
21-50	–	–	–	–	–	–	2	80.0	2	55.0	1	30.0	–	–	–	–	5	165.0	33.0
51-100	–	–	–	–	–	–	–	–	–	–	1	75.0	1	60.0	–	–	2	135.0	67.5
Over 100	–	–	–	–	–	–	–	–	–	–	–	–	1	900.0	–	–	1	900.0	900.0
Total	–	–	–	–	9	85.0	5	111.5	4	71.0	4	133.1	5	990.3	–	–	27	1390.9	51.5

TABLE 92

ESTIMATED TOTAL GAS RESERVES ADDITIONS – U.S. NPC REGIONS – HISTORICAL AND PROJECTED
(Billion Cubic Feet)

	1	2 & 2A	3	4	5	6, 6A, & 7	8 & 8A	Total U.S.
1970	73	40	877	(661)	615	9,377	877	11,198
1971	389	7	905	1,452	1,789	4,678	555	9,775
1972	236	42	585	1,549	1,827	4,716	679	9,634
1973	318	342	1,309	2,905	2,532	(1,428)	847	6,825
1974	240	330	755	1,110	1,750	7,175	560	11,920
1975	240	330	755	1,110	1,750	7,175	560	11,920
1976	240	330	755	1,110	1,750	7,175	560	11,920

TABLE 93

ESTIMATED TOTAL GAS RESERVES TO PRODUCTION RATIO – U.S. NPC REGIONS – HISTORICAL AND PROJECTED

	1	2 & 2A	3	4	5	6, 6A, & 7	8 & 8A	Total U.S.
1970	35.3	9.6	15.4	10.1	9.9	12.4	9.5	11.8
1971	35.0	9.3	12.0	10.0	9.2	11.6	10.0	11.2
1972	37.3	9.8	13.4	9.2	8.1	10.8	10.7	10.4
1973	43.4	10.5	13.3	8.8	7.7	9.7	11.4	9.7
1974	39.5	9.6	12.2	8.4	7.7	9.2	11.0	9.3
1975	36.3	9.0	11.1	8.1	7.6	9.1	10.8	9.1
1976	33.6	8.6	11.1	7.8	7.6	9.1	10.4	9.0

TABLE 94

ESTIMATED TOTAL GAS PRODUCTION — U.S. NPC REGIONS — HISTORICAL AND PROJECTED
(Billion Cubic Feet)

	1	2 & 2A	3	4	5	6, 6A, & 7	8 & 8A	Total U.S.
1970	145	634	1,107	3,930	2,952	12,687	505	21,960
1971	153	589	1,150	3,763	3,043	12,893	486	22,077
1972	146	514	1,202	3,818	3,297	13,064	471	22,512
1973	130	467	1,221	3,914	3,368	13,030	475	22,605
1974	145	493	1,283	3,750	3,164	13,053	501	22,389
1975	160	504	1,361	3,612	3,030	12,594	522	21,783
1976	175	508	1,313	3,456	2,884	12,071	548	20,955

TABLE 95

ESTIMATED TOTAL GAS RESERVES REMAINING AT YEAR-END — U.S. NPC REGIONS — HISTORICAL AND PROJECTED
(Billion Cubic Feet)

	1	2 & 2A	3	4	5	6, 6A & 7	8 & 8A	Total U.S.
1970	5,129	6,099	17,056	40,049	29,509	158,144	4,807	260,793
1971	5,365	5,517	16,811	37,738	28,255	149,929	4,876	248,491
1972	5,455	5,045	16,194	35,469	26,785	141,581	5,084	235,613
1973	5,643	4,920	16,282	34,460	25,949	127,123	5,456	219,833
1974	5,738	4,757	15,754	31,820	24,535	121,245	5,555	209,404
1975	5,818	4,583	15,148	29,318	23,255	115,826	5,645	199,593
1976	5,883	4,405	14,590	26,972	22,121	110,930	5,731	190,632

TABLE 96

PROJECTED NEW GAS PRODUCTION (GAS RESERVES ADDITIONS DIVIDED BY PRODUCTION RATIOS) – U.S. NPC REGIONS
(Million Cubic Feet Per Day)

		1	2 & 2A	3	4	5	6, 6A & 7	8 & 8A	TOTAL
Associated Gas	1974	4.83	43.59	20.55	63.01	45.11	187.87	5.48	370.44
	1975	7.12	45.66	20.55	63.01	46.23	197.26	6.32	386.75
	1976	9.45	47.95	20.55	63.01	46.23	197.26	7.47	391.92
Non-Associated Gas	1974	12.95	49.96	144.25	299.56	589.95	1,964.99	135.71	3,197.37
	1975	13.30	53.75	162.74	316.98	589.95	1,964.99	138.29	3,240.00
	1976	13.67	56.62	177.95	332.44	589.95	1,964.99	140.98	3,276.60
All Gas	1974	17.78	93.55	164.80	362.57	635.06	2,152.86	141.19	3,567.81
	1975	20.42	99.41	183.29	379.99	636.18	2,162.25	144.61	3,626.15
	1976	23.12	104.57	198.50	395.45	636.18	2,162.25	148.45	3,668.52

TABLE 97

U.S. GAS PRODUCTION *VERSUS* GAS WELLS

Historical	Gas Production (BCF)	Producing Gas Wells	Average Well Production (MMCF)
1963	14,546	102,966	141.2
1964	15,347	103,084	148.9
1965	16,252	111,680	145.5
1966	17,491	112,498	155.5
1967	18,380	112,321	163.6
1968	19,373	114,391	169.4
1969	20,723	114,476	181.0
1970	21,960	117,483	186.9
1971	22,077	120,210	183.6
1972	22,512	121,153	185.8
1973	22,605	123,034	183.7

TABLE 98

PROJECTED GATHERING SYSTEMS AND NEW PLANT REQUIREMENTS
(Million Cubic Feet Per Day)

NPC Regions	New Gas (MMCFD)	Gas Gathering Systems: Estimated Daily Quantity to be Gathered (MMCFD)	Gas Gathering Systems: Tons of Steel Pipe Required (Tons)	Gas Gathering Systems: Est. Quantity Gas Requiring New Plants (MMCFD)	New Plant Construction: Estimated Number New Plants	New Plant Construction: Size New Plants (MMCFD)	New Plant Construction: Total Capacity New Plants (MMCFD)
Region 1							
1974	17.78	Nil	None	None	None	–	–
1975	20.48	Nil	None	None	None	–	–
1976	23.12	Nil	None	None	None	–	–
Region 2 & 2A							
1974	93.55	93.55	9,355	None	None	–	–
1975	99.41	99.41	9,941	None	None	–	–
1976	104.57	104.57	10,457	None	None	–	–
Region 3							
1974	164.80	164.80	16,480	164.8	4	40	160
1975	183.29	183.29	18,329	183.3	4	40	160
1976	198.50	198.50	19,850	198.5	4	40	160
Region 4							
1974	362.57	362.57	36,257	140.0	7	20	140
1975	379.99	379.99	37,999	140.0	7	20	140
1976	395.45	395.45	39,545	140.0	7	20	140
Region 5							
					8	10	80
1974	635.06	635.06	63,506	300.0	4	30	120
					1	100	100
Total					**13**		**300**
					8	10	80
1975	636.18	636.18	63,618	300.0	4	30	120
					1	100	100
Total					**13**		**300**
					8	10	80
1976	636.18	636.18	63,618	300.0	4	30	120
					1	100	100
Total					**13**		**300**

TABLE 98 (continued)

Region 6, 6A & 7							
					4	60	240
1974	2,152.86	861.14	86,114	431.0	2	100	200
Total					**6**		**440**
					4	60	240
1975	2,162.25	864.90	86,490	431.0	2	100	200
Total					**6**		**440**
					4	60	240
1976	2,162.25	864.90	86,490	431.0	2	100	200
Total					**6**		**440**
Region 8							
1974	141.19	141.19	14,119	30.0	3	10	30
1975	144.61	144.61	14,461	30.0	3	10	30
1976	148.45	148.45	14,845	30.0	3	10	30
U.S.							
					11	10	110
					7	20	140
					4	30	120
1974	3,567.81	2,258.31	225,831	1,065.8	4	40	160
					4	60	240
					3	100	300
Total					**33**		**1,070**
					11	10	110
					7	20	140
					4	30	120
1975	3,626.15	2,308.38	230,838	1,084.3	4	40	160
					4	60	240
					3	100	300
Total					**33**		**1,070**
					11	10	110
					7	20	140
					4	30	120
1976	3,668.52	2,348.05	234,805	1,099.5	4	40	160
					4	60	240
					3	100	300
Total					**33**		**1,070**

APPENDIX I

Transportation and Fuels

TABLE 99

SUMMARY OF TOTAL FUEL REQUIREMENTS (ESTIMATED)—HISTORICAL AND PROJECTED

(Million Gallons Per Year)

Totals	Diesel	Gasoline	Jet Fuel	Butane
1973	464.0	57.3	14.7	159.2
1974	532.6	63.1	18.6	188.8
1975	571.3	69.5	21.7	190.4
1976	611.1	76.4	22.6	197.6

TABLE 100

ESTIMATED FUEL NEEDS — 1973-1976 — HISTORICAL AND PROJECTED

(Million Gallons Per Year)

	Drilling Rigs				Helicopters*		Boats	Trucking (For Hire)*		Trucking (Service & Drilling Contractor)	
	Diesel	Butane	Heating Butane	Total Butane	Jet Fuel	Gasoline	Diesel	Diesel	Gasoline	Diesel	Gasoline
1973	237.6	120.6	38.6	159.2	14.7	1.0	18.8	151.2	7.9	56.4	48.4
1974	277.7	140.8	45.0	188.8	18.6	1.2	32.1	166.3	8.7	62.0	53.2
1975	284.9	143.3	46.1	190.4	21.7	1.4	35.3	182.9	9.6	68.2	58.5
1976	296.0	149.8	47.8	197.6	22.6	1.54	38.8	201.2	10.5	75.0	64.4

*75 percent production — 25 percent drilling.

TABLE 101

TOTAL FUEL USAGE BY RIGS — 1973

Total (Million Gallons)	Depth (Feet)	Number of Wells	Average Days Per Well	Total	Fuel Per Day (Gallons)
3.6	Under 3,000	4,000	3	12,000	300
23.77	3,000 - 5,000	6,340	10	63,400	375
135.0	5,000 - 10,000	7,721	25	193,025	700
114.5	10,000 - 15,000	2,365	44	104,060	1,100
62.8	Over 15,000	655	80	52,400	1,200
15.0	Cable tools & air	5,000	10	50,000	300
354.7				**474,885**	

NOTE: Offshore rigs fuel usage double that of land rigs (90 offshore rigs X 2,200 diesel gallons per day = 3.5 million gallons per year).

TOTAL FUEL USAGE BY RIGS

Butane	34%
Diesel	66%
Butane	120.6 million gallons per year
Diesel	234.1 million gallons per year
Butane (used for heating)	38.6 million gallons per year

SOURCES: Rowan Drilling Company, Houston, Texas
Loffland Drilling Company, Tulsa, Oklahoma
International Association of Drilling Contractors, Dallas, Texas

TABLE 102

HELICOPTERS* DIESEL FUEL USAGE (ESTIMATED)—HISTORICAL AND PROJECTED

	Number of Helicopters	Fuel Usage Rate (Gallons Per Hour)	Total Jet Fuel† (Million Gallons Per Year)	Total Gasoline (Million Gallons Per Year)
1973				
Medium Helicopters (8 - 14 seat)	45	90		
Small Helicopters			14.7	1.0
(90 percent turbine)	275	25		
Total	**320**			
1974				
Medium Helicopters (8 - 14 seat)	60	90		
Small Helicopters			18.6	1.2
(90 percent turbine)	335	25		
Total	**395**			
1975				
Medium Helicopters (8 - 14 seat)	70	90		
Small Helicopters			21.7	1.4
(90 percent turbine)	390	25		
Total	**460**			
1976				
Medium Helicopters (8 - 14 seat)	75	90		
			22.6	1.5
Small Helicopters	400	25		
Total	**475**			

*75 percent working production; 25 percent working drilling.
†Calculated on basis of 4 hours use per day.
Sources: Petroleum Helicopters, Inc., New Orleans, Louisiana
Rowan Drilling Company, Houston, Texas

TABLE 103

BOATS DIESEL FUEL USAGE (ESTIMATED)—HISTORICAL AND PROJECTED

	Operating Fuel (Gallons Per Hour)	Percent Time	Standby Fuel (Gallons Per Hour)	Total (Gallons Per Month)	Operating 1973		Boats Under Construction*	
					Number of Boats	Total (Million Gallons Per Year)	Number of Boats	Total (Million Gallons Per Year)
Supply Boats	70	50	7	14,000	40	6.72	65	10.9
Tugs	10	50	2½	4,500	101	5.5	35	1.9
Utility	30	5	4	4,440	46	2.45	4	0.2
Crewboats	10	30	–	2,160	118	3.06	11	0.28
Survey	10	10	2½	1,920	50	1.15	–	–
Total					**355**	**18.8**	**115**	**13.3**

*Projection for 1974-1976 as follows:

	(Millions of Gallons Per Year)
1974	32.1
1975	35.3
1976	38.8

TABLE 104

TRUCKS (FOR HIRE) FUEL USAGE (ESTIMATED)

	Percent Use	Total* (Gallons Per Day)	Total (Million Gallons Per Month)	Total (Million Gallons Per Year)
Diesel	95	419,520	12.6	151.2
Gasoline	5	22,000	0.66	7.9

*Based on 10 gallons per hour fuel usage and an average of 4 hours per day operation.

TABLE 105

TRUCKS FUEL USAGE – SERVICE COMPANIES AND DRILLING CONTRACTORS (ESTIMATED)
(Million Gallons Per Year)

	Diesel (Million Gallons Per Year)	Gasoline (Million Gallons Per Year)
Wire Line	5.06	8.54
Drilling Fluids	3.96	15.97
Cementing	36.58	17.7
Drilling Contractors	10.8	6.2
Total	56.4	48.4

TABLE 106

DRILLING MUD INDUSTRY FUEL USAGE (ESTIMATED)
(Million Gallons Per Year)

Diesel Trucks	Gasoline Trucks	Pick-ups and Autos
220 trucks x 50 gals/day diesel = 11,000 gals/day diesel x 360 days = 3,960,000 gals/yr	453 trucks x 60 gals/day gasoline = 27,180 gals/day gasoline x 360 days = 9,785,000 gals/yr	1,875 units x 3,300 gals/yr per unit = 6,187,000 gals/yr gasoline