Chapter 3

Technologies for Arctic and Deepwater Areas

Contents

TABLES

FIGURES

Chapter 3
Technologies for Arctic and Deepwater Areas

OVERVIEW

Technology employed by the offshore petroleum industry has changed dramatically over the past 20 years, allowing the international petroleum industry to explore and produce in environments that were considered almost prohibitive two decades ago. This technology development which has revolutionized the offshore petroleum business is a result of adaptation, innovation, and integration.

Industry began its move to deep and hostile environments by first applying land-based techniques to the marine environment in discrete incremental steps. Progressively, industry resolved the problems encountered offshore by adapting existing systems or techniques or by designing new ones as needed. Experience in the Gulf of Mexico, where exploration and production have moved from land to shallow water to deep water, demonstrates this progression of technology adaptation.

New technologies also have resulted when a major challenge or opportunity called for innovative approaches. For example, dynamic positioning was a major innovation during the government's 1960 Mohole Project; acoustic-guided hole reentry was a major innovation of the government's Deepsea Drilling Project of the 1970s; and innovations in diving and underwater vehicles grew out of Navy programs in the 1960s and 1970s. In private industry, Deep Oil Technology's tension leg platform, IMODCO's single point mooring system, Shell's first semi-submersible rig in the 1960s, Exxon's deepwater guyed tower, and Conoco's tension leg platform in the 1980s are also examples of major innovations.[1]

Finally, the integration of marine and ocean engineering with petroleum engineering and the business of oil drilling and production has brought varied experience to bear on design, construction, safety and reliability. The basic principles of each field have been used effectively to design new systems to develop and produce petroleum resources in the hostile marine environment (see figure 3-1).

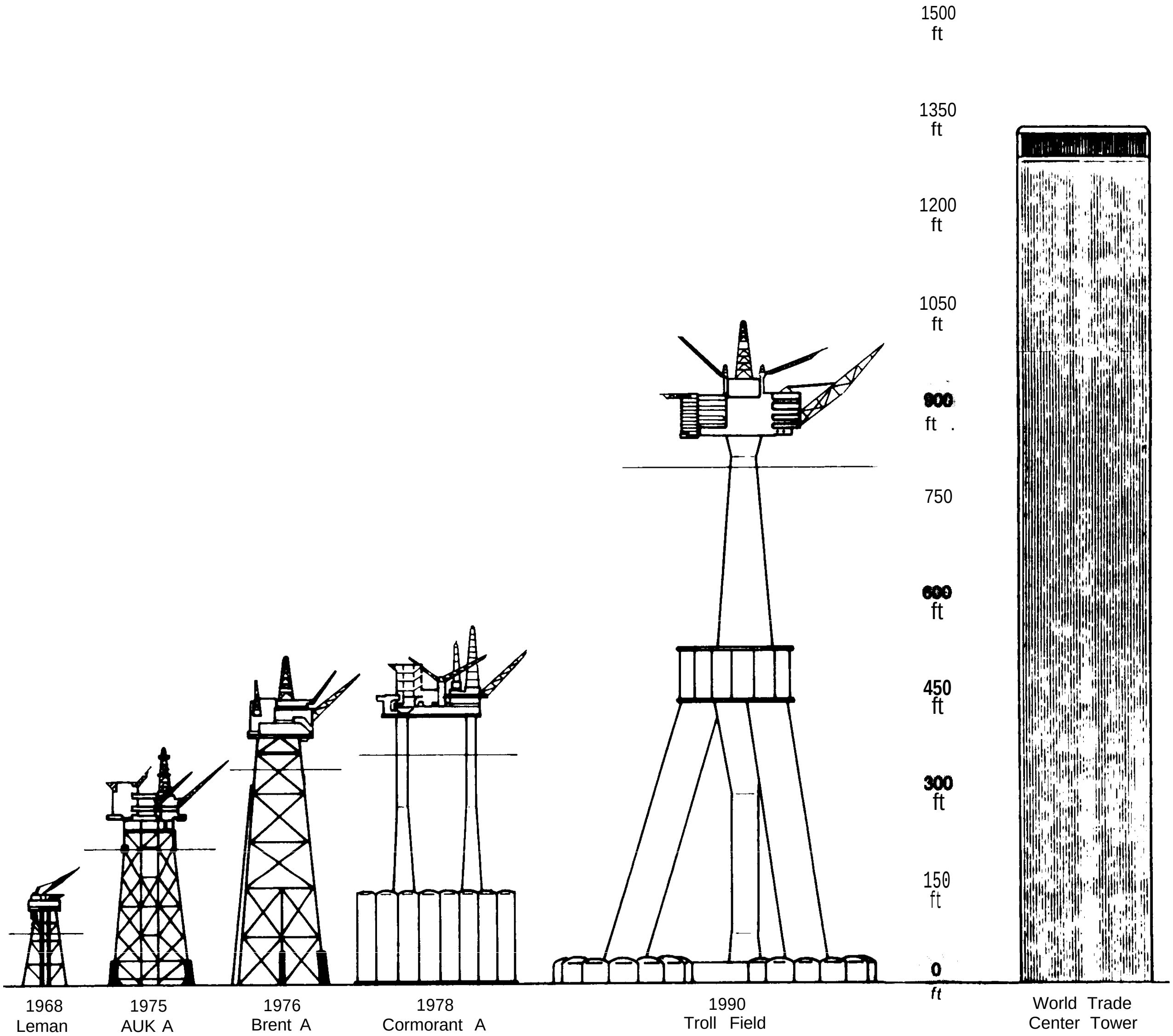
Today more than one-quarter of world oil production is from offshore regions (see table 3-l). That portion has been growing at a rate of nearly 10 percent per year for the past decade, and major exploration activities continue off the East, West, and Gulf Coasts of the United States; in offshore Alaska; in the Asia-Pacific, especially the China Sea; off Latin America, especially Brazil; in the northern North Sea; and off Canada. Several of these regions could be categorized as hostile environments because of storms, severe waves and currents, deep water, or Arctic or sub-arctic conditions.

For example, exploration has been underway for several years under the severe ice conditions of the Beaufort Sea off the United States and Canada; in iceberg conditions along Greenland and eastern Canada; and under severe wind, wave, current, and deepwater conditions along the eastern Canadian and U.S. coasts, in the North Sea, and off southern Australia. Outside of the United States, the major offshore production experience in very hostile environments has been in the North Sea. The major offshore exploration experience in hostile waters (without production to date) has been off the coast of Canada.

The Canadian Beaufort Sea exploration activities have been in the forefront of operations in severe ice and cold conditions. Eastern Canada and U.S. Atlantic Coast offshore exploratory drilling have set rough water records. Exploratory activities in the Mediterranean and off the U.S. Atlantic coast have set water depth records (see figure 3-2).

[1] U. S. Congress, Office of Technology Assessment, *Ocean Margin Drilling—A Technical Memorandum* (May 1980); and *Proceedings of the Offshore Technology Conference* (May 1984).

Figure 3-1.—Progression of Production Platforms for the North Sea



SOURCE Shell 011 Co

In each of these situations, new technologies were necessary for effective operations in very harsh environments. These technologies ranged from deepwater risers to concrete gravity structures to deepwater pipelines. Some examples of production platform technologies for hostile environments are shown in figure 3-3.

Offshore petroleum activities are commonly divided into three phases: 1) exploration; 2) development; and 3) production. Exploration includes some pre-lease activities such as geological and geophysical surveys as well as the exploratory drilling that occurs (in the United States) after a lease sale. Development begins after an oil or gas discovery is determined economic and includes the delineation of the reservoir as well as the drilling of production wells and the design and construction of all facilities for producing a field. Production begins with the flow of oil or gas to a market and concludes when a field is depleted. In offshore frontier regions, it is not unreasonable to expect exploration to con-

Table 3-1 .—World Offshore Oil Production

Region or area	Oil production (million bbl/day) 1983 (actual)	1984 (projected)
Middle East	3.74	3.88
Latin America/Caribbean[a]	3.24	3.36
North Sea	2.88	3.05
United States (GOM + Calif.)	1.68	1.78
Southeast Asia and Oceania	1.53	1.56
West Africa	0.80	0.80
U.S.S.R.	0.18	0.17
Mediterranean	0.14	0.15
Total	14.19	14.75
Percent of onshore + offshore	26.6°/0	27.70/o

[a]Latin America/Caribbean includes Mexico, Venezuela, Trinidad, Brazil, and Argentina as key producers

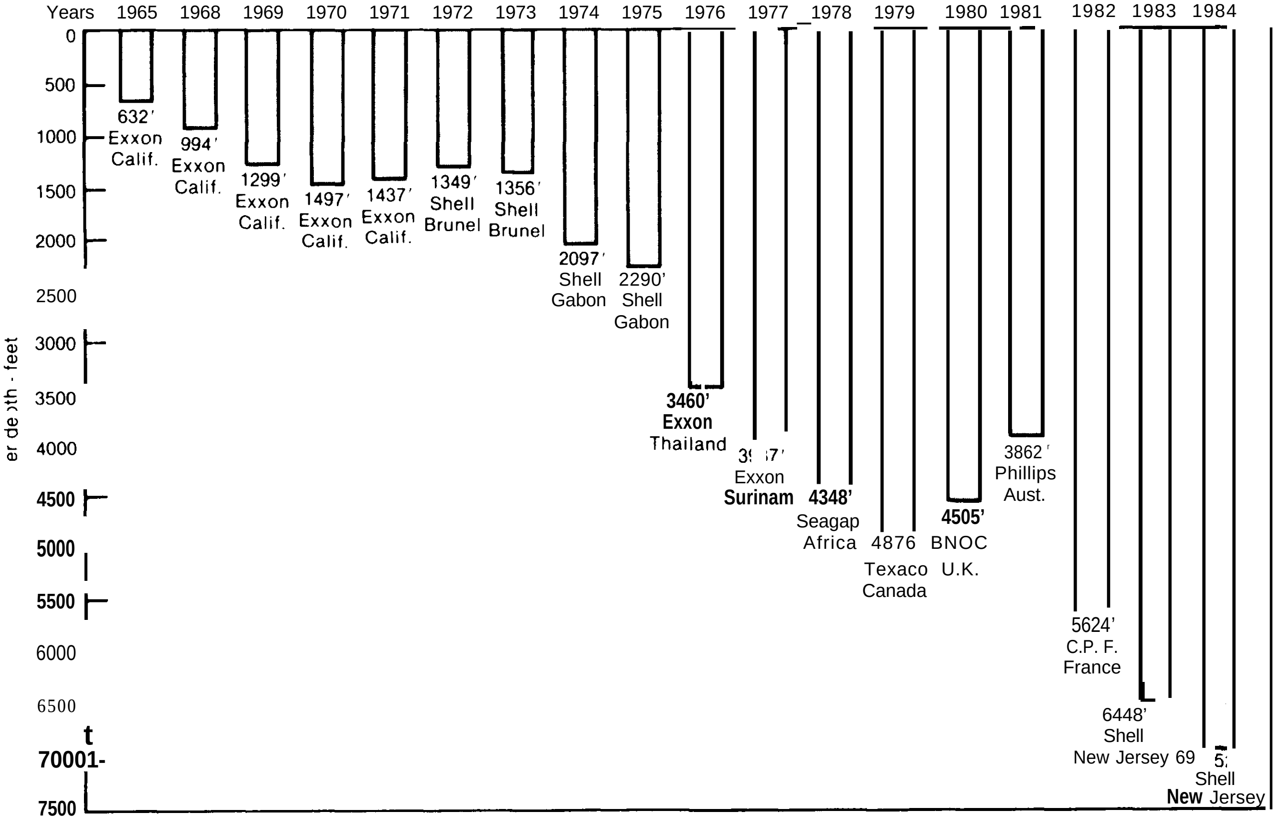
SOURCE *Offshore Magazine,* May 1984

tinue for 10 years or more, development work to continue for 10 years, and production to continue 20 or more years. One would expect, therefore, that if discoveries are made in U.S. deepwater or Arctic regions, the major activities would continue well into the next century.

The three phases described above do not start and end abruptly; they usually overlap to a considerable extent. Exploration for smaller fields may continue long after major fields in a region are in full production. The development of a field may proceed in stages with the addition of gas injection, water injection, or other systems to enhance recovery as the field is being produced. And production usually starts before a field is completely developed, especially if it is very large and complex.

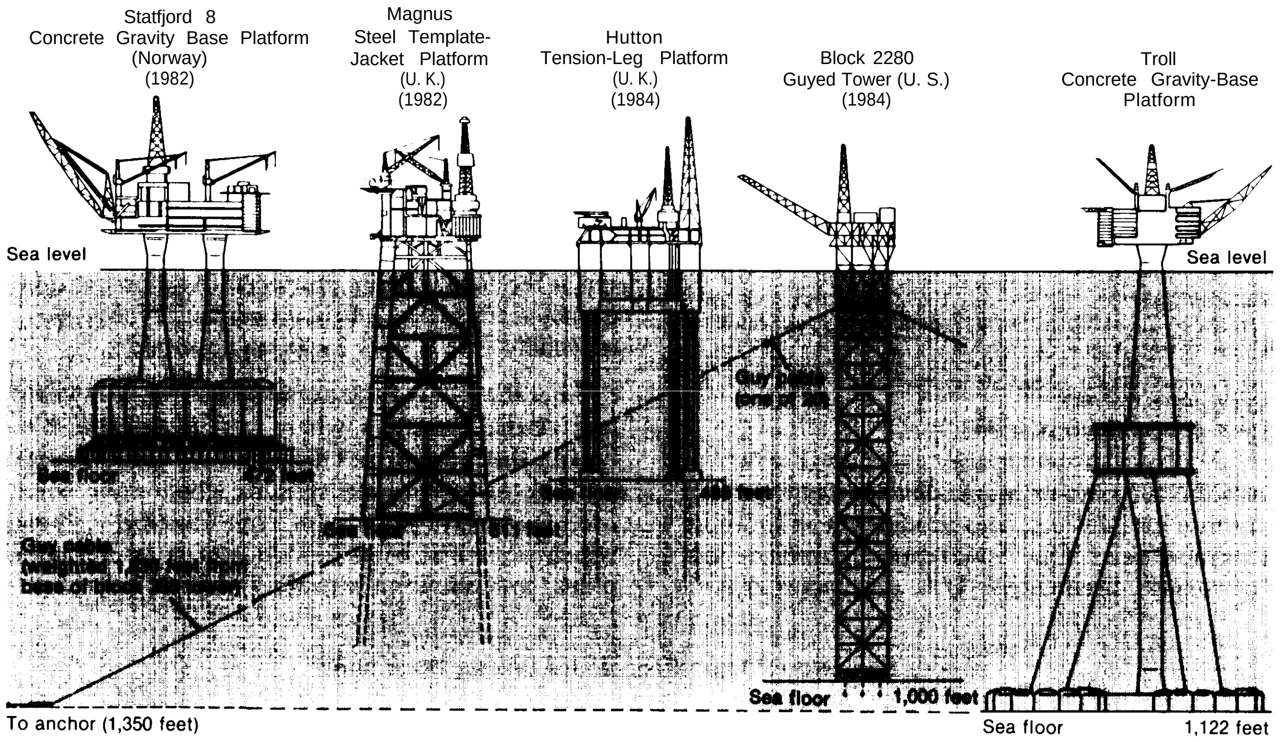
Since the focus of this assessment is the deepwater and Arctic frontiers where no production has begun, the technologies discussed fall into two categories: 1) exploration systems which have been used for several years; and 2) production systems which *have not* been used but exist in designs, plans, and sometimes prototype test equipment.

Figure 3-2.—Water Depth Records for Drilling Operations



SOURCE Proceedings, DOI EEZ Symposium, Nov 1983, updated 1984

Figure 3-3.—Production Platform Technologies for Frontier Areas



SOURCE: *Scientific American*, April 1982.

However, even though these production systems have not been used in the regions under consideration, many individual components are similar to those already in service in other regions. A total technical system will, therefore, be built from a combination of tried and tested subsystems and components newly designed to meet added demands.

The types of drilling, production, and transportation systems for each frontier area must be selected to fit the prevailing conditions of the working environment (e. g., ice, deepwater, or storms), prospective field characteristics, and the proximity to other developments. For example, a discovery in the Alaskan Beaufort Sea near Prudhoe Bay probably would be developed using much of the same technology as that used on the nearby land sites. Because of the site-specific nature of most offshore oil and gas technology and also because of the great variety of technology possibilities available, discussions in this chapter are based on specific systems which may be used in the Arctic and deepwater scenarios developed by OTA.

THE ARCTIC FRONTIERS

Overview

Commercial oil activities in the Arctic date back to a State lease sale in December 1964 onshore in the Prudhoe Bay area. Production from the onshore North Slope fields began in 1977 and in 1984 was 1.6 million barrels per day.

Offshore exploration in the Arctic region began in the mid- 1970s in State waters of the Beaufort Sea, Prior to this, the only significant activity in the Alaskan offshore was outside the Arctic in Cook Inlet and the Gulf of Alaska. Oil production from offshore platforms in Cook Inlet began in 1964. Exploratory drilling in the Gulf of Alaska in the late

1970s produced no discoveries of economic significance.

The first exploratory wells in the waters north of Alaska were drilled from natural islands in Steffenson Sound (e. g., Gull Island in 1974 and Niakuk Island) followed in 1977 by drilling from a built-up sea ice platform in Harrison Bay. Since then, many exploratory holes have been drilled from manmade gravel islands or off the barrier islands along the Beaufort Sea coast. Exploratory drilling in the Bering Sea region began in 1982. Drilling in the Bering Sea has been conducted in the summer ice-free season with technologies that have been used in temperate offshore regions. A concrete island drilling structure is now being used for exploratory drilling north of Cape Halkett in Harrison Bay.

The first Federal offshore activity in Arctic Alaska was the joint Federal/State Beaufort Sea lease sale in December 1979. Since then, the pace of offshore activity and the rate of technological advancement have increased significantly. The first wholly Federal offshore lease sale took place in October 1982 in the Beaufort Sea. To date, the Federal Government has conducted four more sales in Arctic Alaska, three in the Bering Sea—Norton Sound, the St. George Basin, and the Navarin Basin—and a second in the Beaufort Sea (Diapir Field).

In May 1982, Sohio and Exxon jointly announced tentative plans to develop the 350-million-barrel Endicott field (also known as the Sag River/Duck Island field) portion of the joint Federal/State lease sale area. By February 1985, Sohio had received all necessary permits and launched work leading to the first commercial oil production in U.S. Arctic waters. In November 1983, Sohio began drilling the first exploratory hole in the

Mobile offshore exploratory drilling unit, like those used in offshore Arctic areas, is towed to new drilling site

Mukluk area of Diapir Field. However, Mukluk was determined nonproductive. In May 1984, Shell announced a large oil discovery from Seal Island in a joint Federal/State sale area. In both cases, drilling was from manmade gravel islands. Exxon drilled the first exploratory well from an Arctic mobile offshore drilling unit (MODU) in late 1984 northwest of Mukluk. This used a concrete island drilling system known as "Super CIDS, " which can be moved to another location if desired after drilling is completed at the site[2] (see figure 3-4).

Offshore petroleum development in the Arctic will be a major technological challenge. The environment is severe and will dictate a rigorous approach to design and construction of all primary and support systems. While considerable data have been collected, additional engineering data will need to be compiled and verified. The cold temperatures, ice, harsh weather, and remoteness of many Arctic regions will force the use of costly equipment to achieve the required reliability. Some of the exploration and development milestones in offshore Arctic technology are shown in figure 3-5.

Field Characteristics

The field characteristics of the six key Arctic planning areas are given below.

2 'Drillers Seek Alaska Supergiant, *Offshore* (January 1984),

Figure 3-4.—Mobile Offshore Drilling Unit

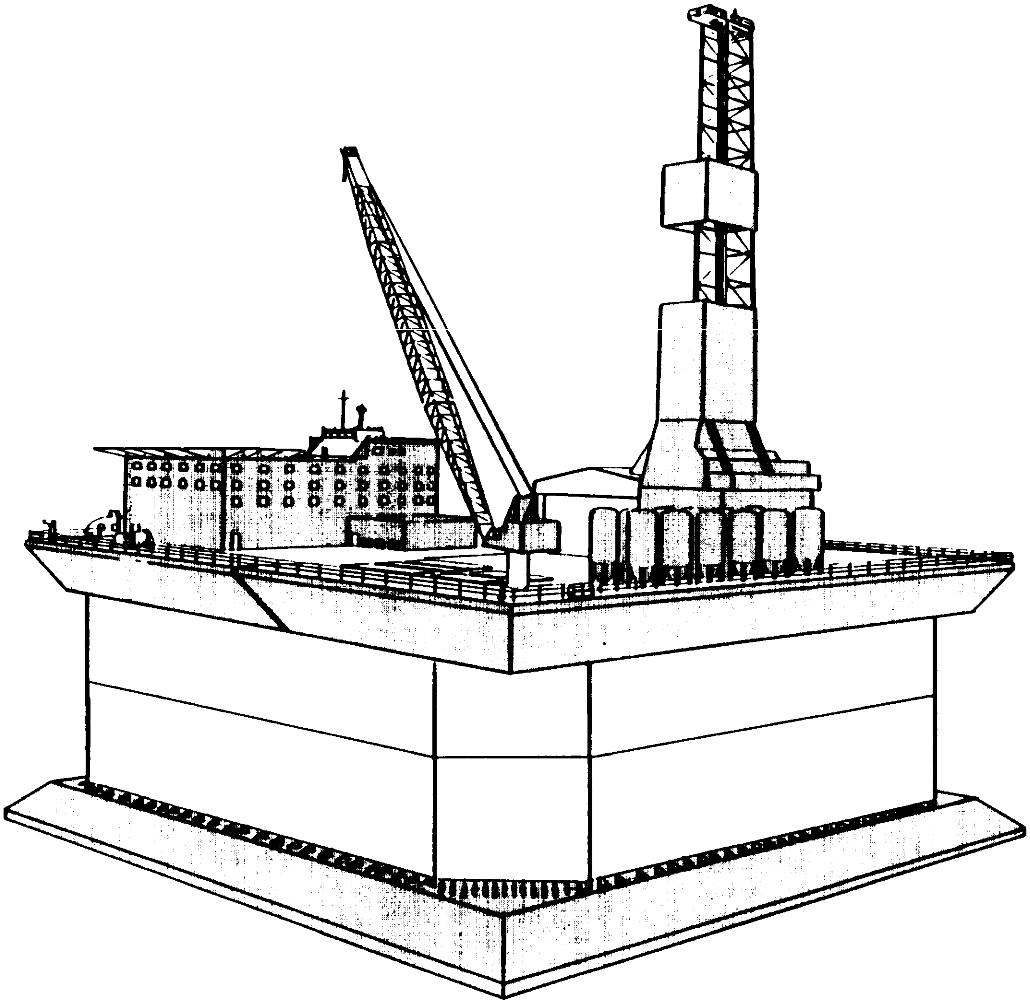
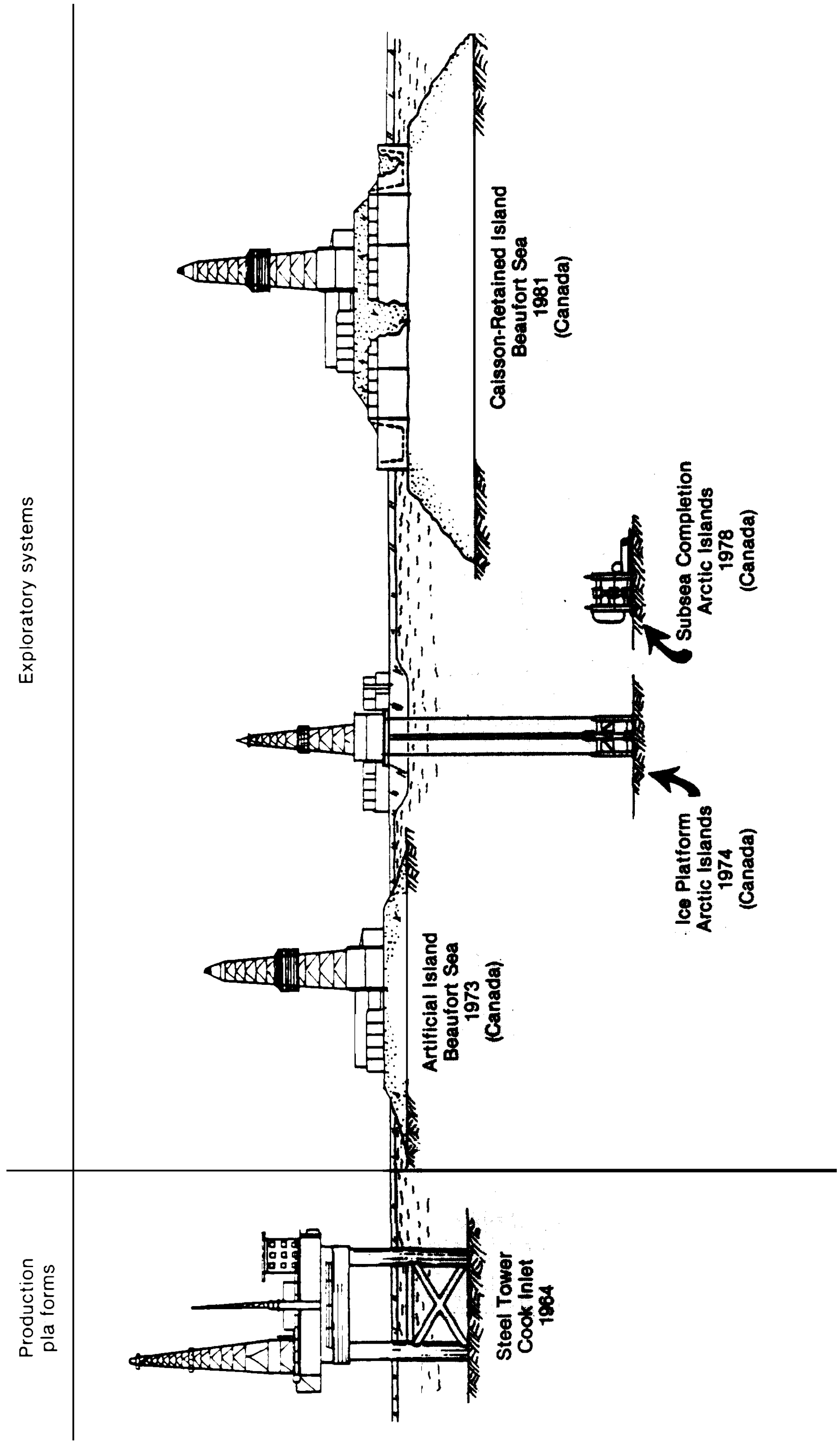


Figure 3-5.—Arc·ic Exploration and Development Milestones



Proceedings of DOI EEZ Symposium, November 1983.

Beaufort Sea

There are four main types of geologic settings in the Beaufort Sea which potentially contain oil. They are listed below in the order of probability. Only the first two are candidates for exploratory drilling at this time.

Ellesmerian Sequence. —This prospective sequence extends from Smith Bay on the west to Mikkelsen Bay on the east, becomes thinner as it extends north from land, and ends at approximately 71°13' N latitude. It includes the Lease Sale 71 area which incorporates Harrison Bay. Since the Ellesmerian Sequence includes the Prudhoe Bay fields, oil similar to the Prudhoe type may be found in the Lease Sale 71 area. This means an oil with an average gravity of about 280 and with a low sulphur content; therefore, a good quality oil. The area of Ellesmerian potential has gentle structural folds which means that it could contain several very large accumulations of oil instead of numerous small ones.

Tertiary Structures. —These structures are east of the Ellesmerian Sequence and extend from Camden Bay to the Canadian border. This means that they are east of the Lease Sale 71 area but within Lease Sale 87 which occurred in August 1984. The seaward extent of these structures is approximately to 70035 N latitude. These structures contain more convolutions and peaks than the Ellesmerian Sequence which means that the area, if productive, may contain more smaller oil fields. These structures also are located in regions of more severe ice conditions.

Growth Fault Structures. —These structures relate to the growth faults and roll-over anticlines. They overlap the Ellesmerian Sequence in the northeasterly portion of Lease Sale 71 and then extend seaward. Little is known about possible oil fields in these structures.

Cretaceus Tertiary Clays. —These formations are expected to contain scattered smaller fields and are less promising than the Growth Fault Structures for finding oil. They are located in the central and western Beaufort shelf regions.

Chukchi Sea

The Chukchi Sea appears to contain three areas with favorable hydrocarbon potential. Most favorable is the Central Chukchi Shelf, which is northwest of Alaska—particularly the area along the northern coast. It contains a very thick sedimentary section and many anticlines. It is the offshore extension of the Colville Trough—the province of North Slope oil and gas. Reservoir rocks are potentially the same as those in the Sadlerochit Group and the Kuparuk River sandstones.

The southern part of the Central Chukchi Shelf and the Northern Chukchi Shelf are the other two potential areas. The southern part is an overthrust zone similar to the foothills province of the Brooks Range. The North Chukchi Shelf contains great thicknesses of (inferred) Cretaceus and Tertiary rocks containing shale diapirs.[3]

Reservoirs in this area could be located from 5,000 to 25,000 feet below the seafloor with an average well depth of 10,000 feet. It is geologically possible that a giant oil field in excess of 1 billion barrels in size could exist in this area.

Norton Basin

Due to the limited geologic information available on Norton Basin, reservoir and production assumptions have been made based on similar geologic basins for which more data were available; specifically, these are the Anadyr Basin of northeast Siberia and Cook Inlet in Alaska. The assumptions are that the average reservoir depths range from 2,500 to 7,500 feet, that the recoverable reserves per acre could range from 20,000 to 60,000 barrels, and that the initial well productivity could range from 1,000 to 5,000 barrels per day. Field sizes could be in the range of 100 million barrels or more.[4]

[3]Dames & Moore, "Chukchi Sea Petroleum Technology Assessment, report prepared for the Minerats Management Service (December 1982).

[4]Dames & Moore, "Norton Basin OCS Lease Sale No. 47 Petroleum Development Scenarios, report prepared for Bureau of Land Management (August 1980).

St. George Basin

The St. George Basin is floored and flanked by folded Mesozoic rocks that extend from southern Alaska to eastern Siberia. Geophysical data and the extrapolation of onshore information to offshore areas suggest that suitable source beds, reservoir rocks and traps all exist within the St, George Basin. Very little data are available with which to speculate on field characteristics.[5]

North Aleutian Basin

The North Aleutian Basin is a large sediment-filled structural depression that underlies portions of the Alaska Peninsula and the Bering Sea. Within the basin, Mesozoic basement rocks are overlain primarily by Cenozoic sedimentary rocks. The information garnered from nine wells drilled on the Alaska Peninsula adjacent to the axis of the basin is encouraging for the prospect of discovering hydrocarbons. The majority of potential oil and gas traps within the basin are believed to be associated with anticlinal structures.

Navarin Basin

Navarin Basin includes three thick sedimentary sub-basins. There are also several large anticlinal structures, smaller folds, diapirs, and stratigraphic traps. There is potential for giant oil fields in excess of 100 million barrels. Due to the great thicknesses of the sedimentary deposit, reservoirs could occur at depths below the seafloor, ranging from shallow to very deep. Reservoir depths are estimated between 6,500 and 11,500 feet in the northern portion of the Basin and between 3,300 and 13,000 feet in the southern portion.[G]

Environmental Conditions

Petroleum resource development in the offshore Arctic is conducted under unique cold-region, high-latitude environmental conditions. Among the conditions are: ice and its many impacts; ocean floor geotechnical properties; seasonal fog; and periods of up to 24 hours of light or darkness. Offshore conditions are severe and the locations are remote and difficult to support. In order to operate successfully and to minimize the risk to personnel, facilities, and the environment, these environmental conditions, and their impact on materials, logistics, operations, and human factors, must be taken into consideration. Because of these conditions, time relationships become critical—not only for exploration but also for data gathering, logistics, production, and virtually every other operational consideration. Figure 3-6 illustrates environmental load comparisons for different structures and regions to show the significance of wave and ice loads.

The northern Alaska environment can be thought of as a frigid desert with some precipitation, low temperature, high wind, and periods of extended fog. The climate in the areas north of the Bering Strait is very harsh. Based on data from the Climatic Atlas, early air temperatures vary from a low of approximately – 470 F to a high of approximately 570 F. Temperatures even lower than – 50° F occur at Pt. Barrow. The areas south of the Bering Strait have a less severe climate. In the Norton Basin, the extreme low temperature is – 36° F; in the Navarin it is – 110 F; and in the St. George it is30 F. The maximum 100-year wind north of the Bering Strait is 97 knots. This increases south of the Bering Strait to a maximum of 108 knots in the Navarin Basin.[7]

[5]Dames & Moor-e, ' 'St. George Basin Petroleum Technology Assessment, repot-t prepared for Bureau of Land Management (August 1980)

[6]Dames & Moore, "Navarin Basin Petroleum Technology Assessment, reported prepared for Bureau of Land Management (June 1982)

[7]W. A. Brower and H. W. Set-by, *Climatic A das of the Outer Continental Shelf Waters and Coastal Regions of Alaska (1977).*

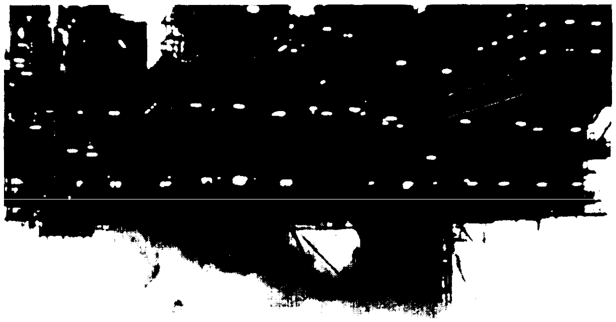
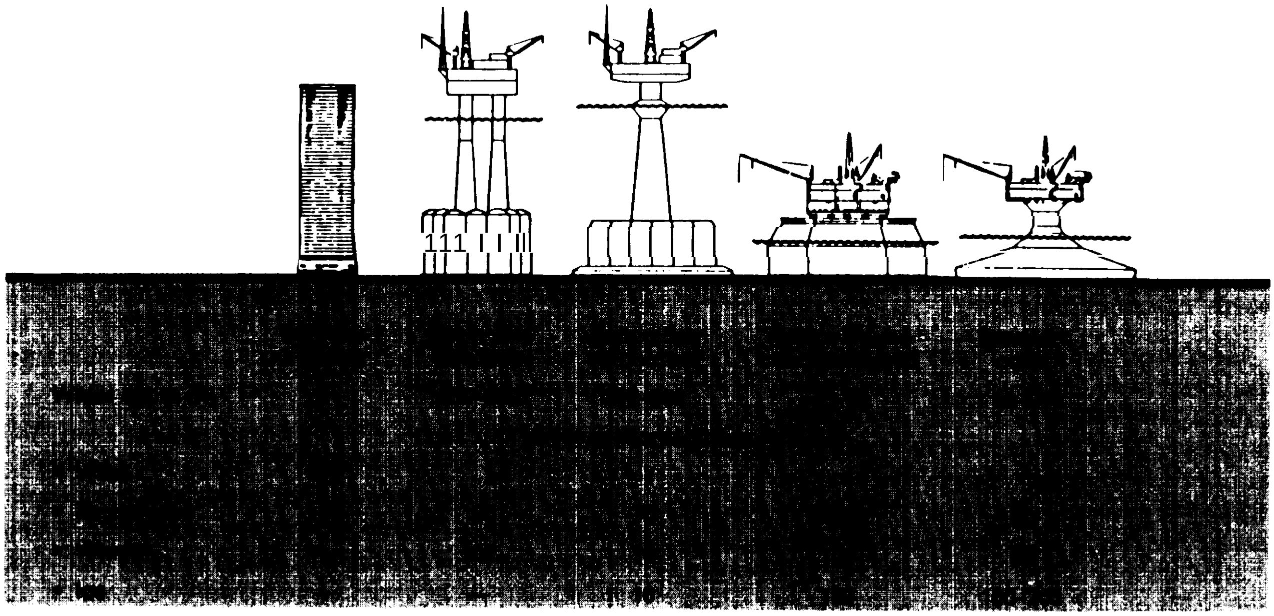


Photo credit: Shell Oil

Offshore platforms in frontier areas must withstand tremendous environmental forces

38-749 0 - 85 - 3

Figure 3-6.—Environmental Load Comparison for Representative Gravity Structures



SOURCE: Hans O. Jahns, "Offshore Outlook-Technological Trends: American Arctic," Offshore Mechanics and Arctic Engineering Symposium (Dallas, Texas, February 1985).

The northern Alaska OCS is relatively stable seismically. A *review* of observations made over the past 20 years in the Beaufort Sea region from the coast out to about 100 miles offshore shows four seismic events, each equal or less than 4.5 on the Richter Scale. Significant seismic activity, however, is located along the Mid-Arctic Ridge in the Eurasian Basin of the Arctic Ocean and along the Aleutian Chain off southwest Alaska. Oil exploration and development operations in the southern Bering Sea must take into account seismic activity along the Aleutian Chain.

There is some controversy about the completeness and accuracy of existing data on environmental conditions in the offshore regions. Some believe the Climatic Atlas data may overestimate oceanographic conditions, while others believe that given extremes may be even greater than existing data. The American Petroleum Institute is sponsoring work to produce a recommended-practice document that will include ranges of wind, wave, and current values based on more accurate and recent measurements. The revised values being considered are shown in table 3-2. Based on these estimates, maximum wave heights could vary from about 40 feet in the Beaufort Sea up to 90 feet in the St. George and Navarin Basins (corresponding to the 100-year storm).

Table 3-2.—Proposed Arctic Environmental Design Conditions

Area	Maximum 100-year wind[a] (knots)	Significant 100-year wave height (feet)	Surface currents velocity (knots)
Beaufort Sea	60 to 80	20 to 30	1 to 6
Chukchi Sea	60 to 80	20 to 30	1 to 5
Norton Basin	55 to 85 (90)[b]	30 to 40[c]	1 to 4
St. George Basin	55 to 85 (88)[b]	40 to 50	2 to 4
Navarin Basin	50 to 80 (90)[b]	40 to 50	1 to 3

[a]These are 1 hour averages to combine with extreme waves. Totally wave independent values would be somewhat higher, but structural loading calculations generally consider joint effects of winds and waves.
[b]These are wave independent numbers.
[c]Values for water depths greater than 75 ft. For shallower water, wave heights are limited by breaking waves.

SOURCE: Exxon, 1984,

Most experts agree that for design purposes sea ice is the most significant environmental parameter in the Arctic offshore. The duration of ice cover can vary from 10 months or more duration for the Beaufort Sea and Chukchi Sea to 1 month or less in the southwest Alaska St. George Basin. In some years there is no ice in the St. George Basin. Since the Navarin Basin is quite large, ice conditions vary considerably from north to south. Ice thicknesses vary correspondingly. The Climatic Atlas data show single-year, plane ice thicknesses of up to 7 feet in Diapir and 2.5 feet in St. George.

Additional offshore Arctic environmental design conditions for five of the lease sale planning areas are shown in table 3-3. These data are derived from the Climatic Atlas and are considered representative although site-to-site variations may be substantial.

Ice

Ice problems largely dictate criteria for Arctic design and operations. Sea ice creates the major difficulties. However, other ice, such as ice islands, floebergs, and structural icing on platforms, ships, and helicopters also present problems. The characteristics of sea ice, pressure ridges, and ice movement are the main concern in the design of Arctic structures. Some ice islands are so large that major damage could result from a collision between them and an offshore structure. Fortunately, because of the scarcity of ice islands, the probability of such an occurrence is relatively low. More likely events are the collision of pressure ridges with certain types of platforms and the ride-up of sea ice onto gravel islands. Ice ride-up can occur when the wind or current forces acting on ice cover force the ice against the land or an offshore structure. If the forces are large enough the ice can be driven up onto the structure or inland for distances of 300 feet or more. Pressure ridge keel seabottom gouging depths are a design concern which influences the depth of burial of offshore pipelines and seafloor well heads.

Sea ice is the single most important environmental factor affecting operations in the Arctic. Ice affects all aspects of oil and gas activities—from the design and construction of facilities which can withstand ice conditions to planning for transportation or possible rescues.

There is no simple description for Arctic sea ice. Even the initial formation of crystals varies widely depending on the roughness of the sea. With calmer seas, the crystals are larger and more platelike. In rougher waters the crystals are smaller and more granular. Once crystals have formed and have developed a thin skin on the surface of the water, the growth of the ice takes place on the underside. Salt brine pockets develop between the lattice networks of relatively pure water crystals. Over a period of time these pockets drain. The process of drainage is complicated by the percolation of summer melt through the ice. Multi-year ice becomes nearly drained of the salt and takes on a bluish hue.

The strength of ice is dependent on many factors including brine content, crystal orientation, temperature, age, and ice type. Recent data show that multi-year ice strengths may fall within the upper range of first-year ice strengths and in some cases (granular ice) may not be as strong. However, statistically and probabilistically, multi-year

Table 3-3.—Arctic Environmental Design Conditions

Area	Temperature: Wind chill (“F)	Temperature: Min (“F)	Ice duration (months)	Ice thickness (feet)	Minimum daylight hours (hours)	Minimum daylight hours (month)	Water depth (feet)	Distance from shore (miles)
Beaufort Sea	-90	-47	10	7	0	‘-Jan. Dec.	33-200	3-40
Chukchi Sea	-85	-44	8-10	5-7	0	Jan. Dec.	30-150	3-45
Norton Basin	-72	-36	8	3.5	4.5	Dec.	30-85	9-62
St. George Basin	-35	3	1-1/2	2.5	7.0	Dec.	344-472	60-180
Navarln Basin	-54	-11	5	3.0	6.0	Dec.	240-450	400-700

NOTES:
1 Wafer depth values represent approximately 95 percent of the water depths — the extreme high and low depths were excluded
2 Distance from shore for Navarin Basin IS from Dutch Harbor in the Aleutians, all others are from the mainland
3 Daylight hours shown are for time the sun IS above the horizon In addition, twilight hours are often added to these numbers, especially for the far north regions.
4 The ice thickness values apply to annual sheet ice

SOURCE W A Brewer and H W Serby, *Climatic Atlas of the Outer Continental Shelf Waters and Coastal Regions of Alaska, 1977* ice is stronger than first-year ice. While first year ice may grow to 6 to 7 feet thick, multi-year ice may grow to about 12 to 16 feet thick. In shallow water, shore-fast ice areas, first-year ice as thick as seven feet has been observed. The ultimate thickness depends on many factors including the radiant solar energy absorbed, long wave period energy radiated from ice into space, temperature of the air above the ice, and the thermal insulation, or inversely, the heat conductivity of the layer of ice and any snow cover. An equilibrium occurs, and the ice thickness is stable when the amount of heat absorbed by the ice from the water is in balance with the heat absorbed from the ice by the air. However, a large amount of thickness ' 'growth' can be attributed to pressure ridge building and rafting.[8]

Sea ice modification results from interactions with the wind and ocean currents, The build-up of forces within the ice floes can cause the fracturing of the plates and a restructuring of the ice. The ice may be split apart resulting in long openings, perhaps tens or hundreds of kilometers long. Should these be sufficiently wide for the passage of a ship or whales they become "leads. Many are very narrow, however, and immediately refreeze or close again as the ice continues to move.

[8]W. F. Weeks and G. Cox, "The Mechanical Properties of Sea Ice, A Status Report, in *Ocean Science and Engineering* (9:2).

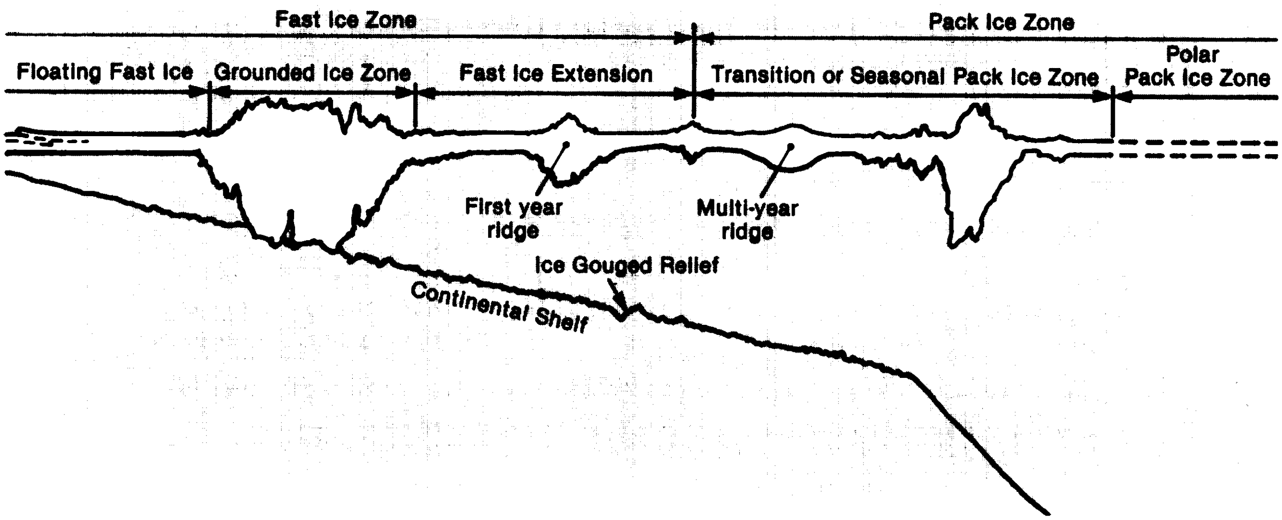
Having once parted, the two walls may be driven together causing upheavals and downward thrusts of the sheets and the formation of pressure ridges. Pressure buildup within ice floes may also cause deformation resulting in pressure ridges and rafting. The surface height of the ridge sails formed may be as much as 25 feet, while the depth of the ridge keels thus formed may be as great as 100 feet.

The restructuring of the broken ice results in various orientations of blocks. Any preferred orientation of ice crystals within the ice structure prior to ridging becomes randomized as broken blocks are tilted and tumbled. Interstices between the submerged blocks fill with sea water. The heat-sink capacity of the ice blocks can cause this water to freeze in the smaller voids and at block-to-block contact points. This often will occur in the first 6 to 8 feet. Also, a strong ice structure can develop in this depth zone due to heat flow to the surface which allows for further solidification of the rubble. Below this depth the blocks will generally form a weaker conglomerate. Rafting of ice of similar thickness will double the local ice thickness.

The location of the ice determines to a great extent how it responds to external forces. The sea ice north of Alaska can be considered as being made up in three zones (see figure 3-7):

1. ***the fast ice zone,*** which includes the grounded ridges, when they exist and any extension of

Figure 3-7.—Arctic Ice Zones



SOURCE U.S. Army Cold Regions Research and Engineering Lab, 1984.

the fast ice resulting from the ice cover being anchored to the grounded ice;

2. ***transition ice zone:*** a transitional zone between the rotating ice pack and relatively motionless fast zones; and
3. *polar pack ice:* mostly multi-year ice that covers the central Arctic Ocean rotating in a gyre.

The shelf north of the Beaufort Sea is narrow: about 50 miles wide and breaks at a depth of 200 to 225 feet. Shallow waters extend over a large portion of the shelf near Harrison Bay with the 60-foot isobath being about 45 miles offshore. Off Camden Bay in the eastern Beaufort, however, the 60-foot isobath is only about 11 miles offshore.

In the Beaufort Sea, the fast ice generally begins to melt in late May-early June. Near the coast this process is accelerated by rivers flooding over the ice surface. Once the fast ice melts away from the shore, its anchorage is lost and it can be moved by wind and currents. Such movement can cause the ice to break into smaller and smaller floes, further accelerating the dissipation process through melting and by being driven away from the area, Open water frequently exists along portions of the Beaufort Sea coast during the months of July, August, and September. The length of the open water season, however, is variable and is frequently controlled by the prevailing winds. Some seasons the winds drive the pack ice offshore far beyond the continental shelf. In other years, onshore winds keep the pack close to shore. During these summers, coastal shipping can be greatly restricted, even prevented. In 1975, some barges supplying the North Slopes were caught and had to winter over in the ice at Prudhoe Bay.

The grounded ridge zone is an area of considerable pressure ridge formation activity. The shallow depth, however, limits keel depths of the ridges. The grounded ridge zone is not continuous, does not necessarily occur at the same locations each year, and, where such ridges form, the resulting ice rubble may be quite extensive and massive or of minor consequence.

The transitional ice zone is one of great energy, The cracks and leads open and close in this zone as the pack deforms under wind and current drag forces. Pressure ridges are formed from floes driven against one another and from the sliding, shearing action between the various ice masses. Keels formed in these may be driven by a combination of wind, current, and ice interactions into water depths shallower than their keel depths. Here the ice keel can be pushed into the seabed, and like a cutting tool, gouge depressions and furrows in the sediments (see figure 3-8). As this happens repeatedly, the seafloor is completely scarred by ice gouges. In water depths of less than 45 feet, ice gouging occurs very frequently, but in these waters shore currents and storms can cause filling by sediment. Beyond the 45-foot depth, ice gouges are not filled and will remain until altered by later ice gouging. Ice gouge orientation tends to follow depth contours.

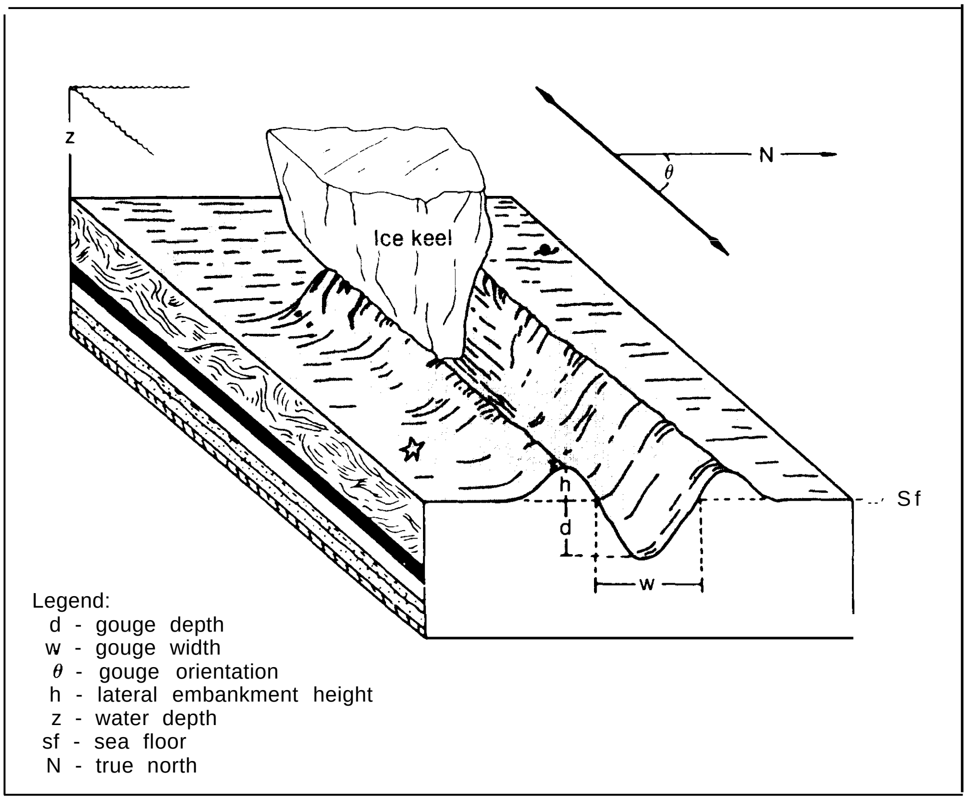
The polar pack region is composed primarily of multi-year ice. However, it too is subject to the interactions of winds, causing leads to open and close. Pressure ridges are continually formed. The ice pack north of Prudhoe Bay drifts clockwise with the movement of the Beaufort Sea Gyre. Ice islands, large icebergs which originate from the northern coast of Ellesmere Island, can also be found drifting within the gyre. These ice islands may be 150 feet thick. Ice islands in this gyre may remain there for decades before leaving the Arctic Ocean. From time to time ice islands are grounded in the coastal waters of the Beaufort Sea.

There are significant differences in the ice in the Bering Sea as compared to the Arctic Basin. The Alaskan shelf south of the Bering Strait is quite wide. The majority of the Navarin Basin lease sale area is in water depths ranging from 300 to 600 feet. Multi-year ice can drift into the northern part of the Bering Sea but even that portion of the sea becomes ice-free during the summer. Ice is formed each year in the northern part of the Bering Sea to thicknesses of about 1 to 2 feet. Fast ice in the very northern Bering Sea may grow to a thickness of more than 4 feet but multiple rafted ice can be over 15 feet thick. Ice starts forming at the shore and extends outward and southward. The edge of the ice may be driven southward by wind forces. Pressure ridging occurs but, like the average ice thickness, is much less than in the Arctic Basin waters. Ridges may have sails of 15 feet above the surface and keels four to six times as deep. Currents through the Bering Strait generally run northward. There is an occasional reversal which can

Photo credit: SEDCO

First mobile offshore drilling unit in U.S. Beaufort Sea—Exxon's Super CIDS

Figure 3-8.—Ice Keel Gouging Sea Floor



(Recent tests indicate gouge depths can vary from 3 feet in shallow lagoons to 15 feet in open ocean water depths of about 100 feet.)

SOURCE: U.S. Army Cold Regions Research and Engineering Lab, Report 83-21, 1983

bring thicker Arctic Ocean ice with larger features southward. The maximum and minimum extents of the sea ice cover in the seas off the Alaska coast are shown in figure 3-9.

Other ice conditions may be hazardous. When combined with freezing conditions, the winds and waves produce an icing spray which can cause dangerous ice build-up on ships and structures. The interactions of blocks of floating sea ice with waves can propel the ice into the sides of ships and structures resulting in large localized forces. During some atmospheric conditions, fixed wing aircraft and helicopters traveling at critical altitudes can be subjected to icing, creating dangerous situations.

Other Factors

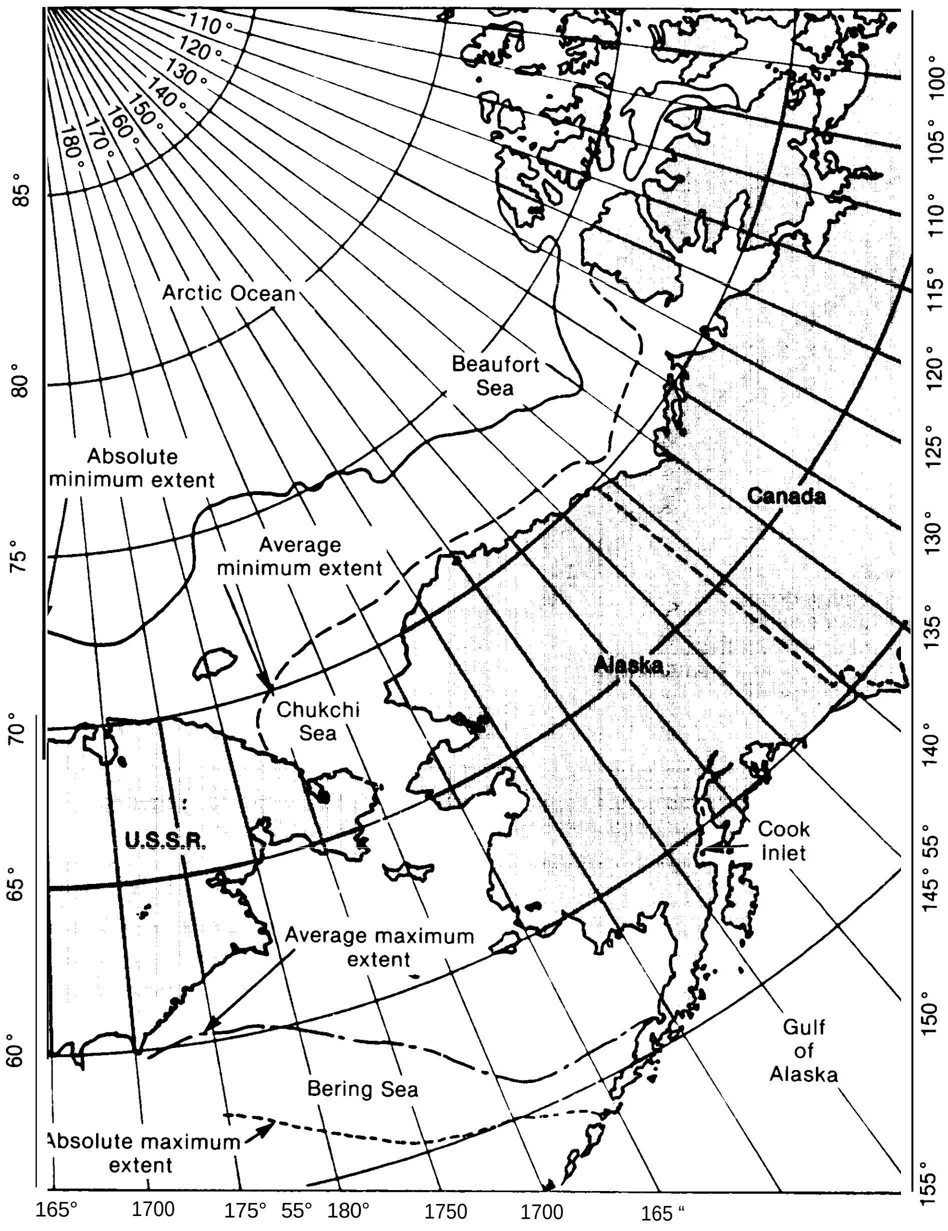
Fine, silty sediments and sub-bottom permafrost are the two geotechnical factors of concern in Arctic waters. Permafrost exists only in the Arctic Ocean. In the southern part of the Bering Sea near the Aleutian Chain, seismicity is also of concern.

The engineering properties of the upper sediments of the ocean floor must be considered in the design of foundations for bottom-founded structures. The possibility of mud slides must be considered in the foundations of structures placed on the steeper slopes of the Navarin Basin. Industry is conducting investigations of the instability of sediments and the design of foundations for these conditions.

Permafrost could affect the design and routing of pipelines in the Beaufort Sea. Some related design problems include the differential thaw subsidence of permafrost and adjacent foundations, thaw subsidence around wells, and frost heaving.

Figure 3-9.— Extent of Arctic Sea Ice

Summer Minimum and Winter Maximum



SOURCE: American Geographical Society, New York, New York, 1975.

In general, the Arctic environmental factors affecting the design, installation, and operation of offshore systems vary depending on the season of operation and upon the ice conditions. But data on ice condition, oceanographic, meteorological, and geotechnical factors are relatively sparse for many areas. And, like all Arctic operations, collection of additional data is costly.

Meteorological data are particularly sparse for the areas north of Alaska and in the Bering Sea. Satellites and ice buoys are used to obtain ice movement and weather data for the regions north of Point Barrow. However, much of the sensory data do not have the resolution necessary for many applications. Unfortunately, most of the visual sensors are usable only during the daylight summer months, and even then their effectiveness is lowered due to clouds and fogs that develop above melting ice and evaporating ice melts. The lack of sufficient ice and meteorological data has severely limited the ability to detect and forecast ice movement and weather conditions for the Arctic region.

Technology Development

OTA has developed three Arctic scenarios to illustrate the approaches that may be used to develop and produce Alaskan oil discoveries, based on today's knowledge of the environment and suitable technology (see box). A complete production system for these conditions does not currently exist. Because of the very high costs involved, there is a significant incentive to improve system reliability and cost effectiveness by using advanced technologies. A range of engineering development, tests, and evaluation may be required before industry can safely and economically produce possible petroleum discoveries in hostile offshore Arctic environments.

Figure 3-10 illustrates some of the production platform systems and structures that currently appear to be the most favored alternatives for each of the Alaskan offshore planning areas. In each case, the system is based on operating experience in a related situation or a similar environment.

Technology for exploring, developing, and producing oil and gas in offshore Arctic environments appears to be progressing at a pace compatible with government leasing schedules and industry's contemplated development schedules. Prior to a sale in a planning area, industry usually proceeds with research and engineering programs to develop baseline data, design criteria, and engineering designs for exploration and production systems which match the expected conditions. This research and engineering effort is intended to: 1) establish the feasibility of systems and the confidence that these systems can be constructed and operated safely; 2) estimate system costs to guide in economic evaluations of the resource prospects, and thus help establish the lease bid level; 3) identify key site-specific information needed for system selection and design if oil and gas discoveries are made; 4) ensure that post-lease sale exploration, development, and production could be brought onstream on approximately the time table assumed in pre-lease sale economic analyses; and 5) enable industry to move quickly to drill exploration wells.

After the discovery of economic reserves resulting from exploratory drilling, considerably more research and development, data collection, and testing is necessary for industry to move into the development and production phases in the Arctic. Some research and development areas are more critical than others, especially when economics are considered. The following areas are judged to be important to future Arctic development.

Ice

Additional research is needed to obtain basic data on ice properties and ice strengths under different conditions as actually encountered in the field, on the strength characteristics of pressure ridges and of the ice within such ridges, and on variations of ice properties.

Although data on ice and its properties are high on the list of needed research, there is a significant data base on ice strengths and properties. Industry is developing more data on ice feature size and geometries and conducting model tests to investigate ice/structure interactions. Ridges are being sampled, their ice strengths determined for the appropriate ridge thermal profile, and ridge temperatures are being monitored throughout the year. In almost all cases, exploratory drilling structures are instrumented to measure the loads exerted by

Arctic Technology Scenarios

In order to assess the technology associated with exploration, development, and production of oil and gas in the Arctic frontier of the Outer Continental Shelf, OTA developed three scenarios that describe a range of potential environments, technologies, and base systems that could be typical in these areas.

For each scenario, OTA also developed time and cost estimates for all phases of exploration and production. These estimates were discussed at OTA technology workshops and then modified based on comments from workshop participants. Cost estimates for the scenarios were derived from the 1981 National Petroleum Council report, adjusted for 1984 dollar equivalents. These estimates, however, are indicative only of broad cost ranges; more precise and reliable costs can be derived only when a specific discovery is delineated and a production system designed for a particular site and set of operating conditions. These cost estimates, and variations on them for different field sizes, also are used in chapter 5 to analyze economic factors.

The Arctic scenarios are for three areas: the Harrison Bay area of the Beaufort Sea (Lease Sale 71), the Norton Basin (Lease Sale 57), and the Navarin Basin (Lease Sale 83). Data were collected about environmental conditions, and assumptions made about exploration, development and production, infrastructure and support services, and transportation for these scenarios. The general considerations related to those assumptions are discussed below.

The schedules start with the date of the lease sale and end with peak production—a time span ranging from 11 years for Norton Basin to almost 15 years for Harrison Bay. These assumptions are optimistic in that they are based on the minimum times for obtaining the necessary governmental approvals. Some industry experts believe that as much as 2 or 3 additional years should be added to the schedules to allow for all permitting and approvals.

OTA estimated the total costs of exploratory drilling to range from $435 to $825 million for the three Arctic scenarios. Total capital costs for development of the prospects in the three scenarios were estimated to be from $2 to $11 billion, including the cost of drilling development wells, obtaining equipment, and building islands or platforms. OTA estimated total operating costs during the production phase at $102 million per year for Norton Basin, $168 million per year for Harrison Bay, and $240 million per year for Navarin Basin. Abandonment costs were estimated to range from $200 million to $1.1 billion.

Environmental Considerations

Environmental conditions in the Arctic strongly influence the technology scenarios. These conditions include temperature, ice, amount of daylight in the winter, distance from shore, water depth, and other factors such as storms, waves, and soils.

Extremely low temperatures, such as those found in Harrison Bay, have a significant impact on working conditions and operating practices. Clothing must be designed to protect workers adequately and survival gear must be provided at operating sites such as gravel islands in case travel is disrupted. Working areas must be enclosed, and outdoor jobs scheduled carefully. In such conditions, special low-temperature steel must be used to avoid failures in brittle steel, and equipment must be operated continuously to ensure proper viscosity oil and lubricants. In the Navarin basin, the cold temperatures combine with high winds and waves to cause spray icing on upper structures.

Ice conditions—including duration, thickness, and movement—are perhaps the most critical of the environmental considerations because they govern design and access. In the Norton Basin, for example, dynamic ice movement imposes significant constraints on structure design. In Harrison Bay, the shore fast ice zone limits ice movement to some extent, but the offshore pack ice still will transmit thermal stresses and forces that result in some mov[illegible] may be transmitted to frozen-in structures during severe storms. [illegible] multi-year floes, [illegible] fragments also may drift into the nearshore waters of Harrison Bay and become frozen into the fast ice. In Navarin Basin, the 450-foot water depths and high waves combined with ice forces could impose large forces acting to overturn bottom" founded structures. Although such structures are installed in t@ North Sea at equivalent depths, they are not subject to the horizontal ice forces that would be encountered in the Navarin Basin, and Arctic structures would require additional strength margins.

Ice and temperature conditions also affect transportation and support services. In the Navarin Basin, the frequency of ice ridges are important for *@"~@? because @F thick ice floes Or areas of rafted ice can be avoided or their effects mitigated by icebreakers. In Harrison Bay and Norton Basin, keels from pressure ridges could penetrate the seabed, requiring pipelines to be buried beneath gouge depth. Although no major marine pipeline systems exist in Arctic waters, trenching by subsea plows and pipeline installation by the bottom tow method are considered feasible. In Harrison Bay, however, permafrost precautions would be necessary to prevent the hot@ from melting the permafrost and possibly causing soil subsidence. While these conditions have been handled successfully onshore on the North Slope, pipeline trenching into subsea permafrost 10 to 20 feet deep would require costly and massive machinery not Yet built Or tested. As a result, most plans for developing nearshore fields in the Beaufort Sea favor building a causeway to support a pipeline to shore.

Soft soils—a potential problem in some areas of Harrison Bay and the Navarin Basin-could require either soil strengthening or more elaborate foundation designs. Potential approaches used elsewhere to overcome soft soils include piles, wicks or drains, replacing the soil with gravel, cement infection to strengthen soils, larger bearing surface areas for gravity structure, and dredging out the soft-bottom to reach freer soil underneath. Structures for soft sea bottoms have been designed for pre-lease sale technology verification and structure costing in Navarin Bay, but extensive site-specific soil surveys would be required for final design of bottom-founded or gravity structures.

Finally, strong bottom currents and storm waves and surges will be critical design considerations for structures, pipelines, and support systems in the Norton and Navarin Basins. In the Norton, storm waves can cause liquefaction in some of the finer sediments (e.g., near the Yukon delta). In the Navarin, which has the most severe winds and waves of all the Alaskan Arctic planning areas, a semi-submersible drilling unit—the most stable platform under severe weather conditions—would be required. The unit would maintain its position with anchors where bottom conditions are suitable, or with dynamic positioning equipment including computer-controlled main propulsion and thruster units and acoustic signals emitted by beacons on the seafloor. Similar semi-submersibles have been used successfully in the North Sea and eastern Canada under severe weather conditions.

Exploration

The type of exploratory drilling rig is determined by site and environmental conditions. As noted above, exploratory drilling in the Navarin Basin would require a semi-submersible. In Harrison Bay, a gravel island (similar to those already in use in the nearshore areas of the United States and Canadian Beaufort Sea) would be used, with the gradual slope and reinforcing sandbags protecting against the erosive action of water and ice. In 50 feet of water, such an island would be 300 to 400 feet in diameter at the top with a gradual slope to the seafloor base diameter of approximately 1,000 feet. Elevation above water level would be about 20 to 25 feet. Alternatives to the gravel island platform include mobile structures such as CIDs which is now in use in the Beaufort Sea. In Norton Basin, open water season is long enough to permit exploratory drilling from a jackup rig and the operation would be similar to those using jackups in the North Sea or eastern Canada.

Development

The technology for field development is determined by site and environmental conditions, as well as the size of the field. However, design requirements for production structures are more stringent than those for exploration due to the larger investment in wells and the longer service life of the equipment. The 2@ to 3&year life of a field implies a greater probability of encountering more severe environmental conditions {e.g., the 100-year storm).

The **scenarios assume** that gravel islands (possibly with cassion-retained protection) would be used for field development in Harrison Bay and Norton Basin, and gravity platforms in Navarin Basin. The oil would be treated on the gravel islands or gravity platforms, and stored in either onshore or offshore storage tanks (Harrison Bay and Norton Basin) or in gravity structures (Navarin Basin). Alternatives to gravity storage now under consideration by industry include moored tankers tied to an icebreaking, single anchor leg mooring; totally subsea storage; and steel jacket platforms with internal storage.

Large gravel islands may become prohibitively expensive as water depth increases beyond 50 or 60 feet. An alternative preferred by some is the bottom-founded gravity structure similar to those used in the Canadian and U.S. Beaufort Sea for exploratory platforms. Designs are proposed for many types of these structures including conical shapes to reduce ice forces. Another advantage of such a structure is the ability to construct it in one piece at a shipyard and then tow it to the site for installation, thus lowering onsite construction costs substantially.

Infrastructure and Support Services

In addition to the severe environment, the primary consideration in designating infrastructure and support services is the distance of the field from established bases onshore. For example, the established facilities at Prudhoe Bay provide the basic infrastructure for operating in Harrison Bay. Work camps, maintenance shops, living accommodations, and catering operations already exist, and procedures for working and coping with the environment have been established. However, reliance on the Prudhoe Bay infrastructure as the sole support base could have prohibitively high transportation costs, and a satellite base closer to Harrison Bay would be needed.

Some support for Norton Basin exists at Nome, but it is not nearly as extensive as at Prudhoe. In anticipation of increased oil activity, Nome plans to build a deepwater harbor—a causeway with docking facilities. Alternatively, Dutch Harbor could be used as the support base.

Navarin Basin poses the greatest logistics problems of the three scenarios because it is so remote. Dutch Harbor on Unalaska Island in the Aleutians-a World War 11 Navy base and already a base for oil company exploration operations and a center for fishing activity—could be a support base for Navarin. Dutch Harbor is ice-free so all necessary supplies and equipment could be transported thereby conventional cargo vessels year-round. It also is a potential location for a storage and transshipment terminal. Other developed Aleutian harbors such as Cold Bay have been considered but at present lack sufficient harbor facilities or water depth. Even Dutch Harbor, however, is too far from the Navarin Basin to be the sole support base, and a forward base may be established on either St. Matthew Island or St. Paul Island. Use of St. Matthew Island poses environmental and regulatory concerns because it serves as a wildlife refuge.

Transportation

Selection of combinations of transportation modes are governed by the southern markets to be served, reliability, magnitude of field development, costs, and the availability of spare TAPS capacity as North Slope onshore production begins to decline in a few years. The most likely transportation scenarios for the three production areas were chosen. Critical considerations include offshore pipeline depth sufficient to avoid ice scour and ice keel gouging, and permafrost protection for subsea pipelines in Harrison Bay, and the cost of various tanker and terminal variations for long-distance transshipment from Norton and Navarin Basin. Some recent industry studies have shown that use of ice-reinforced tankers with icebreaker suport is the most cost effective system for Navarin and Norton. Also, the use of a transshipment terminal does not appear economical until production rates go beyond 1 million barrels per day.

Arctic Scenarios

Parameters	Harrison Bay	Norton Basin	Navarin Basin
Environmental conditions:			
Temperature and wind chill	Extremely low: –47°F, 15 knot winds; –90°F wind chill temp.	Moderately low: –36°F, 11 knot winds; –72°F wind chill temp.	Low: –11 oF, 25 knot winds; -54°F wind chill temp.
Ice conditions	Severe: 10-month coverage; within shore fast ice zone; plane fast ice 7 ft, rafted ice 22 ft, ridges 75 ft	Moderate: 8-month coverage; smooth ice 3.5-4 ft, rafted ice 15 ft, ridges 75 ft; dynamic ice movement	Light-moderate: 5-month coverage; smooth ice 3 ft, rafted ice 12-18 ft; ridge frequency more critical than thickness
Winter daylight	None in Dec. -Jan., 2.5 hr/day in Nov., 6.5 hr/day in Feb.	Some	Some
Approximate distance from shore	20 mi	40 mi	400-700 mi
Water depth	50 ft	50 ft	450 ft
Other	Permafrost precautions to prevent melting and subsidence	Strong bottom currents, storm waves and surges; potential for gas-charged sediments	Severe storms, wind-driven waves, spray icing; remoteness poses extreme logistics problems; soft soils potential
Exploration:			
Number of wells	6	6	6
Type of rig	Arctic land rig on gravel island[a]	Jackup	Semisubmersible
Development:			
Peak production rate (B/D)	500,000	125,000	500,000
Type of platform	Gravel island[a]	Gravel island[a]	Gravity platform[b]
No. of platforms/islands[c]	7	4	7, plus 2 service
Number of rigs	2 per island	2 per island	2 per platform
Total number of wells[c]	271	136	271
Field size (billion barrels)	2.0[d]	0.5	2.0[d]
Initial production (B/D)	4,000	2,000	4,000
Infrastructure and support services:			
Support base	Prudhoe Bay; closer satellite base	Dutch Harbor; some facilities in Nome	Dutch Harbor or Cold Bay; forward base on St. Matthew Island or St. Paul Island; 2 advanced service bases
Air service	Daily; Deadhorse (Prudhoe Bay area), Fairbanks and Anchorage	Commercial airport in Nome	Commercial airport in Nome; helicopter from forward base
Land access	Year-round–Dalton Hwy from Fairbanks; winter ice roads on land fast ice	None	None
Sea access	Annual sealift for barges in open water season (Aug. -Sept.)	Deepwater harbor planned in Nome; Dutch Harbor ice-free year-round for conventional cargo vessels	Deepwater harbor planned in Nome; Dutch Harbor ice-free year-round for conventional cargo vessels
Transportation:			
To shore	Pipelines-buried beneath gouge depth with permafrost protection	Onshore or offshore storage tanks to offshore deep draft mooring and transfer terminal foronloading to 250,000 DWT ice-reinforced tankers with icebreaker escorts	Storage in gravity structures;[e] offshore deep draft mooring and transfer terminal for onloading to 150,000 DWT ice-reinforced tankers with icebreaker escorts’
Onshore	Along-the-shore pipeline connects with TAPS offshore; or pipeline to west coast of Alaska with ice-reinforced offshore tanker terminal		

[a] Fo,50 ft water depths and greater in Harrison Bay and Norton Basin, several alternatives to gravel islands exist and may be preferable depending on gravel availability, exact water depths. soils, and other site-specific conditions. The alternatives are concrete, steel, hybrid structural built as caissons or complete bottom-mounted units.

[b] Principal alternative platform is a steel, pile-founded structure; choice depends on site conditions.

[c] The number of platforms and wells selected for each scenario is probably a minimum. Total number Of wells includes injectors.

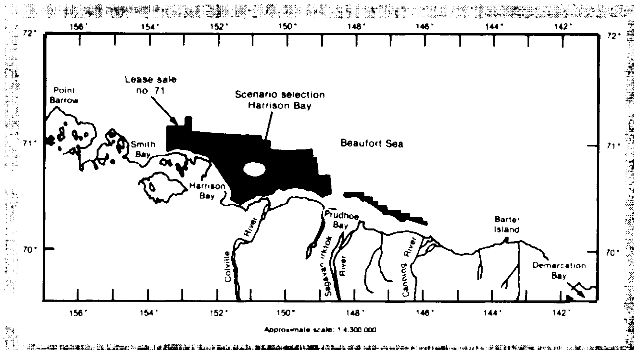
[d] Such a large field size is rare, and this assumption is disputed by industry experts. This report does not assume that this Is the moat likely field size, but only indicates how development might proceed with such a field size.

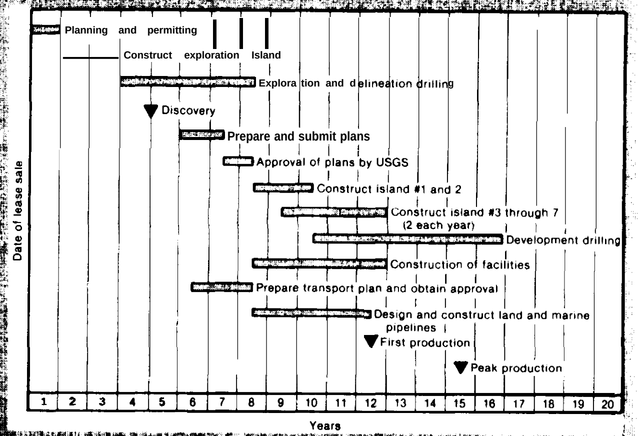
[e] Gravity platforms have been used in the rough weather conditions in the North Sea with a large background of experience for firmer soil conditions and 110 ice.

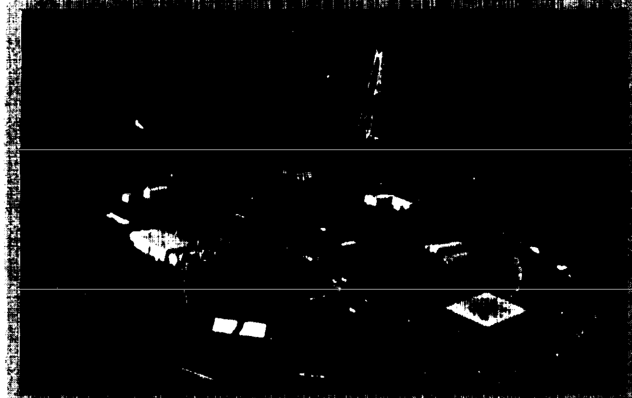
[f] Transportation alternatives include a pipeline to St. Matthew Island or one of the Pribilof Islands for transfer to tankers; use of a transshipment terminal in the Aleutians; and use Of icebreaking tankers.

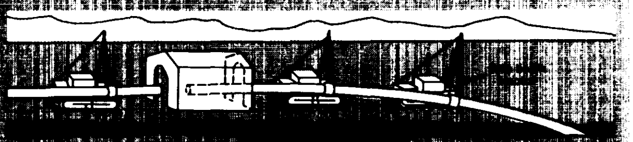
SOURCE: office of Technology Assessment.

Harrison Bay Scenario (Beaufort Sea)

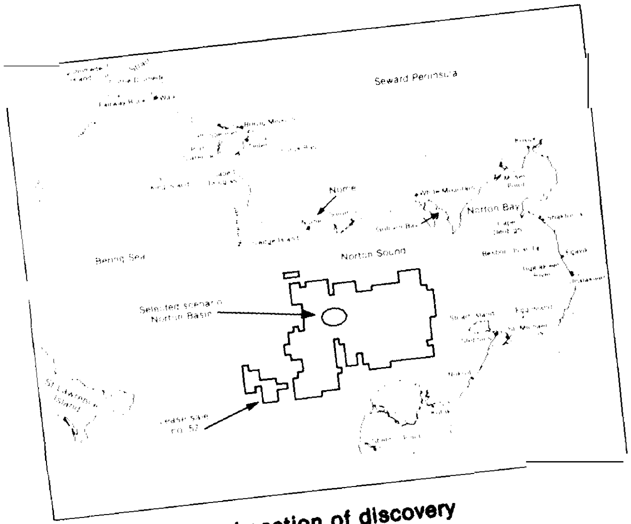




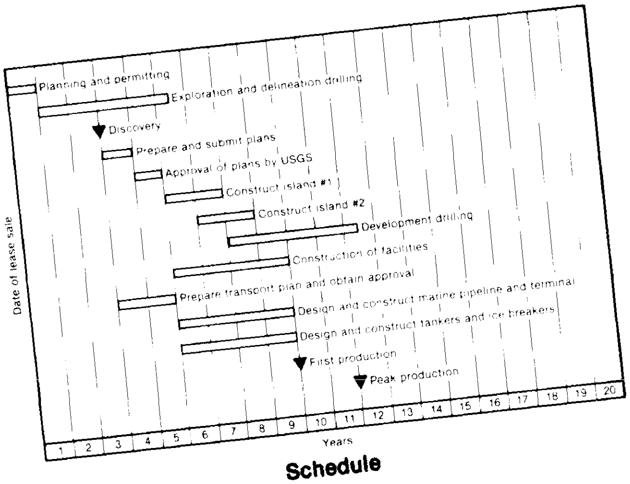




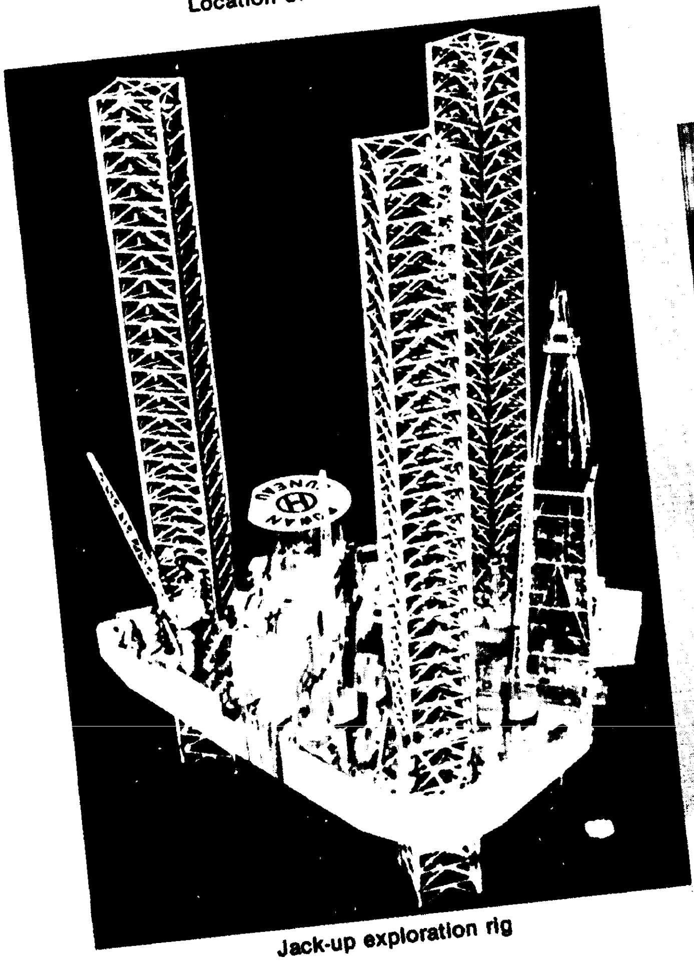
Norton Basin Scenario (Northern Bering Sea)



Location of discovery



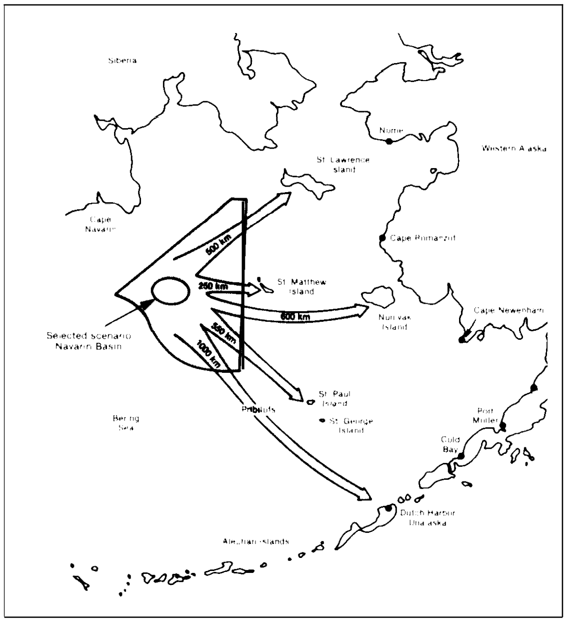
Schedule



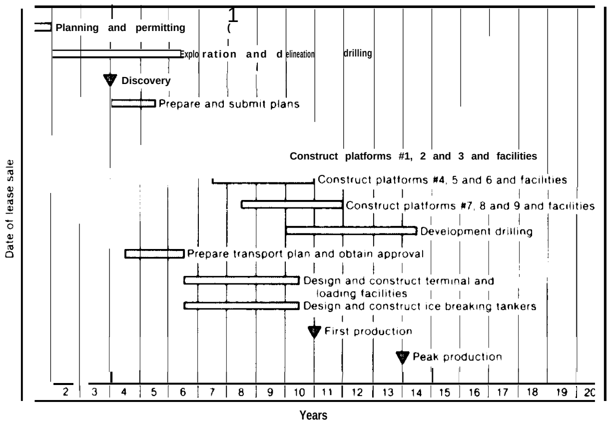
Jack-up exploration rig

Gravel island production platform

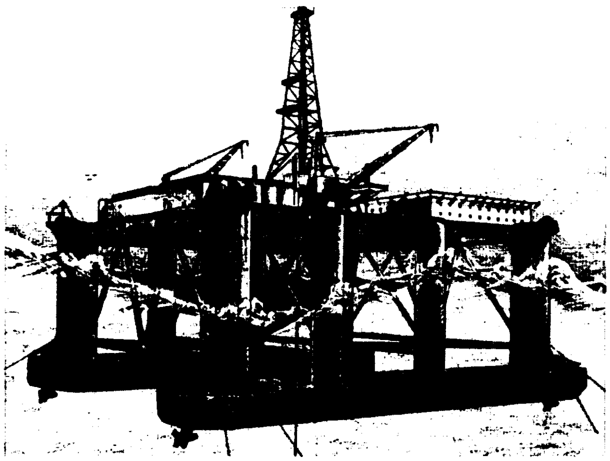
Navarin Basin Scenario
(Central Bering Sea)



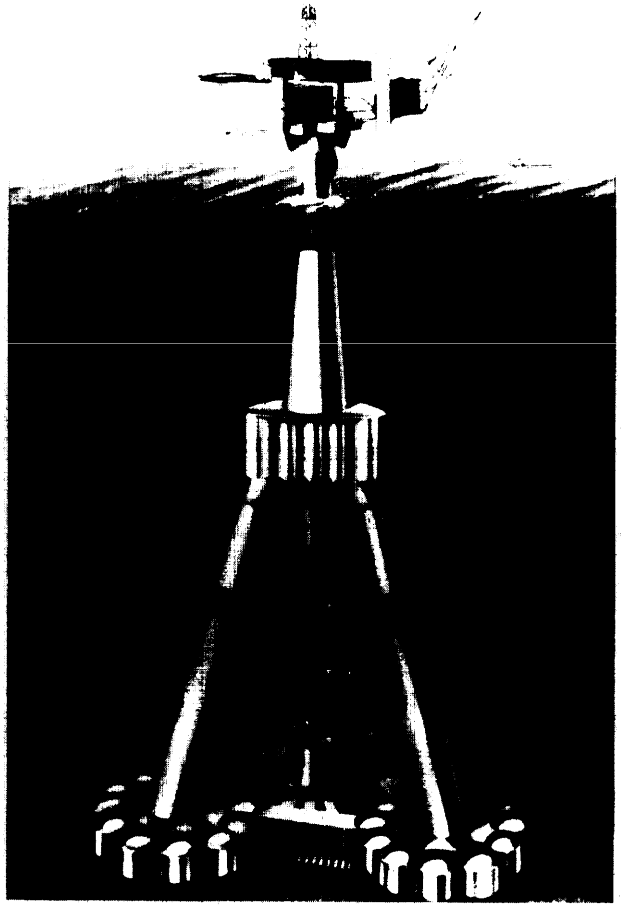
Location of discovery



Schedule

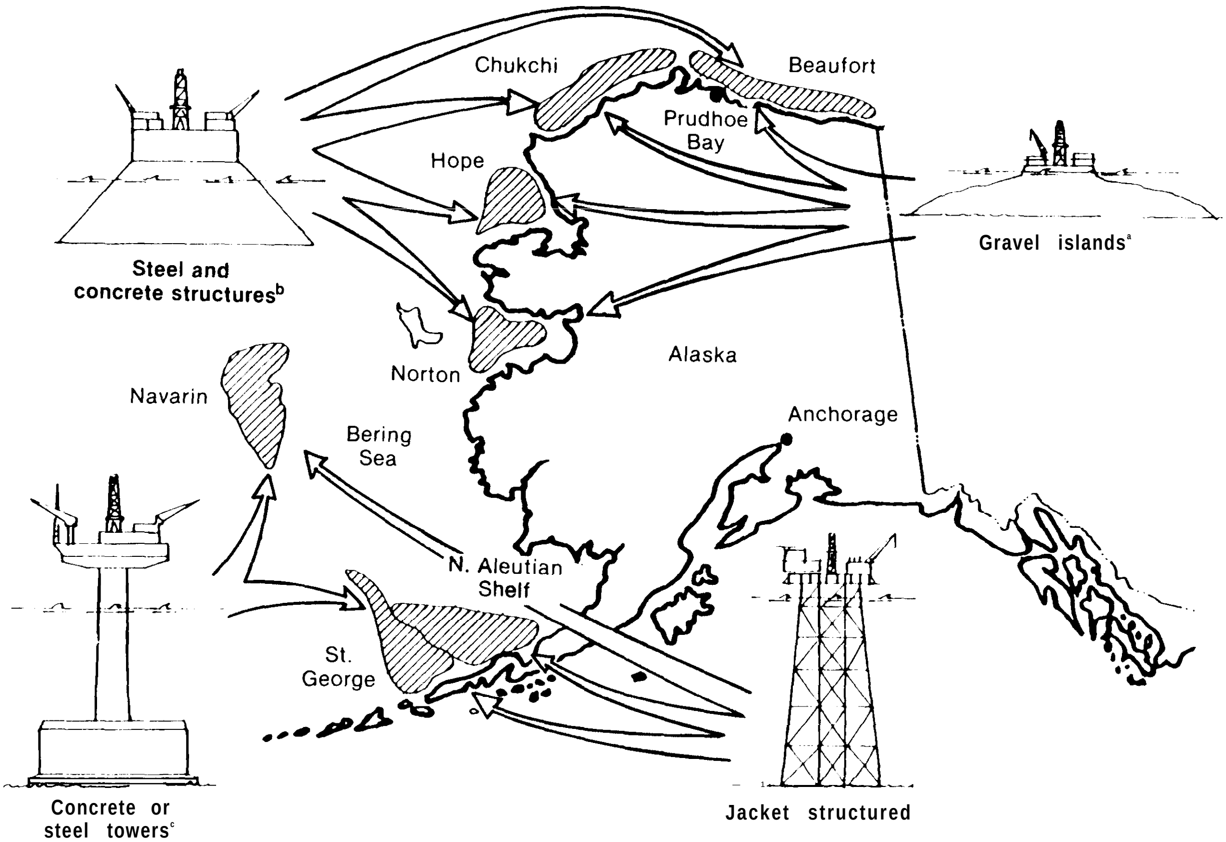


Semisubmersible exploration rig



Gravity production platform

Figure 3-10.— Alternative Arctic Production Structures



[a]Most offshore exploratory drilling has been done from these man-made Islands and the first offshore development (in 40 ft water) is likely to use a gravel island platform.
[b]One such cassion-type platform now in operation in Alaskan Beaufort for exploratory drilling (CIDS)
[c]These types of structures would be extension of technology developed for North Sea
[d]These structures may be extension of both North Sea and Cook Inlet developments

SOURCE Proceedings DOI-EEZ Symposium, Nov. 1983

sea ice. Other programs have made use of natural islands to make load measurements. [9]

Ice Reconnaissance

Increased surveillance from satellites and by aircraft is needed to provide real time data. Ice surveillance is important for structural design purposes, logistics, and tanker transportation design and planning. Many companies have utilized all relevant satellite data to describe ice conditions. Ice movements have been measured for several years by wireline movement stations and drift buoys. Helicopters and fixed wing aircraft are used to assist in making ice forecasts for operations that could be hampered by ice invasions.

Marine Pipelines

More rapid and effective trenching techniques below ice-gouge depths, and rapid and effective techniques for alignment, connection, and repair of pipelines are essential. Recognizing that Arctic pipelines are a critical future design problem, more cost-effective installation techniques and designs for areas with warm subsea permafrost are being investigated. Repetitive surveys are being conducted in the Beaufort Sea to assess gouge depths and the rate at which gouges are being filled by wave and ice actions on the seafloor.

[9]Artic Petroleum operators Association, *Description of Research Projects* (Calgary, Canada, 1982 and 1983); American Society of Mechanical Engineers, *Proceedings of the Offshore Mechanics and Arctic Engineering Symposium* (New Orleans, 1 984); and *Proceedings of the Offshore Technology Conference* (May 1984).

Photo credit: Mobil Oil Co.

Concrete gravity platform in the North Sea

Tankers

Development of design data to permit more confidence in the design of icebreaking tankers, especially those which could successfully operate in the Beaufort and Chukchi Seas on a year-round basis, will be important.

Seismicity

For two of the planning areas, St. George and North Aleutian Basins, a unique problem exists concerning strong motion seismic (earthquake) activity associated with the subduction of the Pacific plate beneath the North American plate. Research is needed to collect seafloor response data, to develop wave propagation and attenuation models, and to establish soil response characteristics.

Those projects are indicative of the scope of research and engineering programs underway by the oil industry. In addition to programs that are proprietary to individual companies, over 275 joint industry programs that deal with wide-ranging aspects of Arctic technology have been undertaken by member companies of the Alaska Oil and Gas Association (AOGA) (see table 3-4). Many Canadian design projects, strength tests, and model tests are also applicable to the U.S. offshore,

Table 3-4.—Summary of Cooperative Arctic Research Projects

	Area						
Subject	N. Aleutian	St. George	Navarin	Norton Sound	Chukchi	Beaufort	General
Ice properties, physical	0	5	15	14	14	62	—
Ice properties, mechanical	—	—	—	—	—	—	15
Waves	3	4	2	2	1	9	1
Currents	2	3	3	4	1	7	—
Geotechnical	6	4	2	4	2	11	2
Structures	2	4	7	4	4	17	19
Oil spill	—	—	—	—	—	3	9
General technical	—	—	—	—	—	1	14
Transportation [c]	—	1	2	2	1	6	2
Cost wells	1	2	1	2	—	—	—
Whale mammals	—	—	—	1	—	3	1

[a]Ice Mechanical property studies are considered common to all lease areas.
[b]This includes equipment used fo, research, such as stress sensors, and operations, i.e., ice movement detectors and measurement devices.
[c]This includes pipeline and tanker studies.

SOURCE: Alaska Oil and Gas Association (AOGA), Technical Subcommittee of the Lease Sale Planning and Research Committee, January 1985.

THE DEEPWATER FRONTIERS

Overview

The petroleum industry has developed technologies incrementally as exploration and production have moved from shallow to deepwaters. In this progression, as the severity of the environment has increased, additional design requirements have been recognized. To meet these requirements, offshore structures have become larger and more costly. The logistic support for construction and operation has likewise increased. Government agencies have also had to increase their capabilities to monitor industry's activities to assure safety and environmental protection.

This section discusses technologies for oil and gas development in water depths greater than 1,320 feet. There has been extensive exploration at such depths but no production to date. Many of the technologies required for deepwater production are available although not applied commercially at this time, As new technologies are applied to deepwater frontier areas, testing and verification will be needed. Some new concepts may be abandoned and others developed further. Safety is a major concern in offshore engineering and construction. Technologies used must provide reliability, not only to assure human safety but also to minimize the risk of losing a platform or other structure and to minimize operational costs.

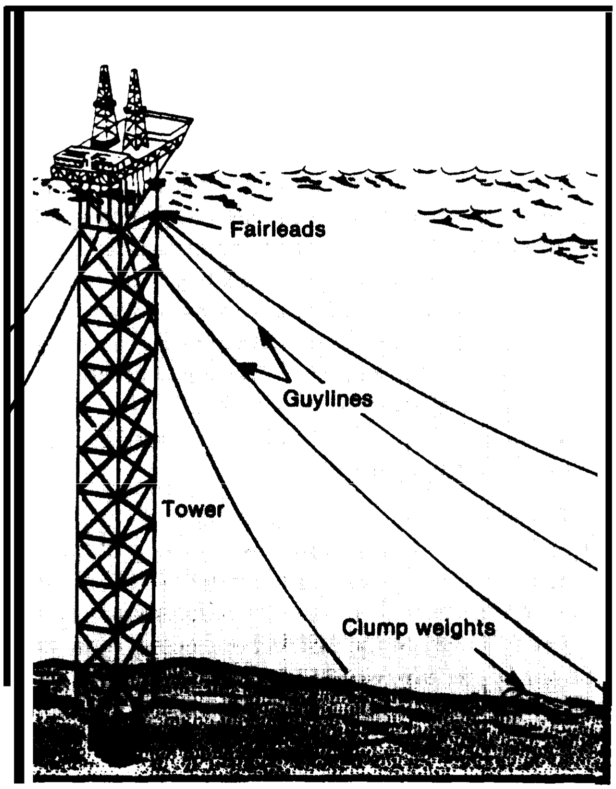
A number of technological areas are critical in deepwater petroleum development. These include: 1) structural design, which ranges from the metallurgy of the steels or composition of materials used, through welding techniques and ocean floor platform foundation engineering; 2) techniques for installation, maintenance and repair of structures, risers, and pipelines; 3) drilling, well control, and completion; and 4) technologies for support operations, such as diving and navigation. Human diving capability is limited to approximately 1,640 feet, with only experimental dives to 2,300 feet. Thus, one-atmosphere manned vehicles and remotely controlled unmanned vehicles may become increasingly important for support services. Navigation technologies are important during seismic surveys, exploration drilling, and platform and pipeline installations. This includes acoustic, radio, and satellite technologies for seismic survey navigation; directional drilling; and ship, submersible, and remote vehicle operations.

Historically, the offshore petroleum industry has a good record of developing adequate technology to meet ever more challenging conditions as development has moved to more hostile environments farther offshore. Some existing systems—especially compliant platforms and subsea wells—have the capability of fairly direct extension to deeper water. Others—e.g., deepwater risers, control and well maintenance technologies—may need further development for use in deep water.

New technological achievements are being made continually as new resource discoveries are made in deeper waters. For example, in Norske Shell's Troll Field in 1,148 feet of water in the North Sea, a large concrete gravity structure is under detailed design and testing. Exxon has initiated production from its Lena guyed tower in approximately 1,000 feet of water in the Gulf of Mexico (see figure 3-11). Other structures are planned for Gulf of Mexico discoveries in up to 1,500 feet of water.

In addition, advanced conceptual designs exist and some component testing has been accomplished for systems to be used in water depths up to 2,000 to 2,500 feet. Among these systems are Exxon's submerged production system, Chevron's subsea wellhead system, and Conoco's tension leg platform. It is reasonable to expect that in a few years several types of structures and production systems will be built for use in these water depths.

Figure 3-11 .—Guyed Tower



Beyond about the 2,500-foot depth, there has not yet been as much activity aimed at developing specific production systems because opportunities for significant petroleum discoveries at that depth are still more speculative. However, oil exploration in deepwaters of the U.S. Exclusive Economic Zone (EEZ) is underway. Sonat's drillship Discover Seven Seas drilled for Shell Offshore, Inc., in water depths of more than 6,000 feet in the Wilmington Canyon area of the Atlantic coast during 1983-84. Other leases have been sold in the Atlantic with water depths of about 7,500 feet. Blocks were leased in water depths of approximately 5,800 feet in the April 1984 Gulf of Mexico sale. And blocks in approximately 10,000 feet of water are now being offered offshore California.

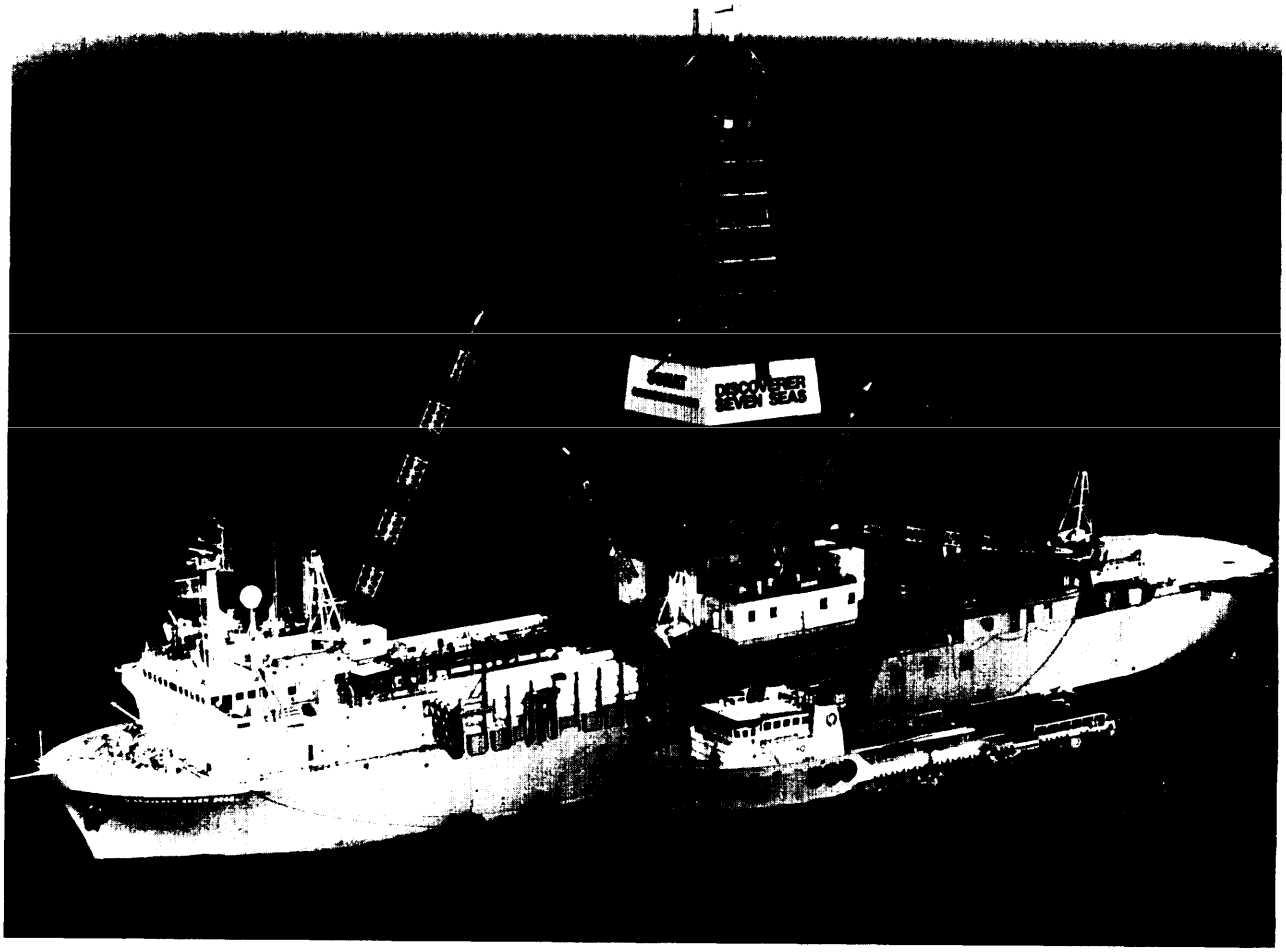
Deepwater achievements of various system components are shown in table 3-5. The history and status of subsea well and facility water depth records are shown in figure 3-12.

Based on its deepwater drilling and production achievements, the petroleum industry believes that there are no significant technological limits to operations in up to 8,000 feet of water. Petroleum basins which are developed in the deepwater frontiers will require new technologies which will be deployed for the first time. Because these new systems are being developed continually, it may not be reasonable to establish water depth or other regulatory limits based on present technologies. But sufficient precautions must be taken to assure that the gov-

Table 3-5.—Deepwater Drilling and Production Achievements (through March 1985)

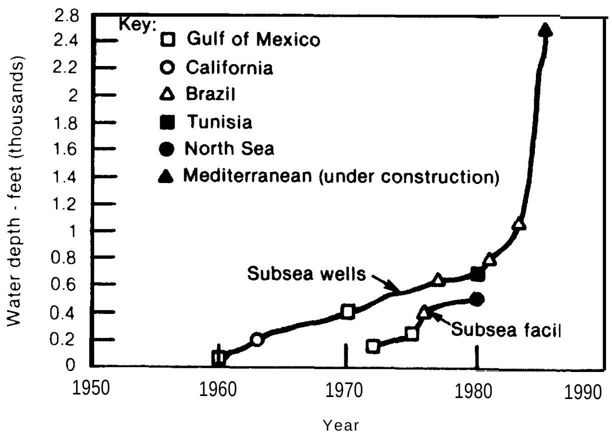
Component or activity	Record water depth experience to date (feet)	Place, date
Exploratory drilling	6,952	U.S. Atlantic, 1984
Development drilling	2,500	Mediterranean, 1983
Fixed steel/production platform	1,025	Gulf of Mexico, 1978
Guyed tower production platform	1,000	Gulf of Mexico, 1983
Floating production platform . .	460	Tunisia, 1982
Tension leg platform	485	North Sea, 1984
Subsea wellheads	1,007	Brazil, 1984
Subsea production system	500	North Sea, 1982
Deepwater pipeline	2,060	Sicily, 1979
Tanker loading systems	530	North Sea, 1980

SOURCES: *Proceedings of the Offshore* Technology Conference (1984); USGS Circular 929, EEZ Symposium *Proceedings* (November 1983); *Ocean Industry* (July 1984); *Engineering News Record* (Aug. 16, 1984); Oil *and* Gas *Journal* (July 16, 1984 and Oct. 15, 1984)



M

Figure 3-12.—Subsea Wells & Production Facilities History and Current Status



SOURCE DOI EEZ Symposium, November 1983, update 1984

ernment regulations imposed on offshore operations are appropriate and the responsible government agencies monitoring offshore operations have the skills and technology necessary for judging the adequacy of industry's engineering designs, equipment, and procedures.

Field Characteristics

The three key offshore planning regions including deepwater frontier areas are the Atlantic, Gulf of Mexico, and the Pacific. This section describes the field characteristics for these three regions.

Atlantic

Since there have been no commercial oil discoveries in the Atlantic region, it is not possible to predict the field characteristics. There is reason to believe, however, that some of the reef formations present in the Bay of Campeche, Mexico, may extend northward to the deepwater basins in the Atlantic. If this is the case, oil fields could be similar to the prolific offshore fields with high well flow rates now producing in Mexico, If such fields were found in the Atlantic, it would be a significant commercial discovery.

Gulf of Mexico

The Gulf Coast reservoirs range in size from very small (less than 5 million barrels of recoverable oil) to major oil fields of over 100 million barrels. The median oil field size is 29 million barrels and the mean size is 66 million barrels. Of the 105 analyzed oil fields, 21 are over 100 million barrels. These reservoirs also vary widely in other characteristics. Formations often consist of unconsolidated sands which require gravel packing and hole conditioning. Generally, production rates are modest. A 1,500-barrel-per-day well in the Gulf of Mexico is considered very good. Drilling rates (feet per day) are high. This high drilling rate may not be sustainable in deepwater if the upper formations require several casing strings to be set near the surface. More often 4 weeks is required to drill a deepwater well. As experience is gained, these deepwater operations may speed up.

Pacific

All the known West Coast oil fields lie off central and southern California. Many of these fields produce relatively heavy oil. In addition, the oil often contains sulfur. The West Coast oil is shipped to the Gulf Coast for refining.

Drilling is slower and more difficult in this region. Structures are often faulted and are hard to delineate. However, there are some very large and productive fields in California. The Point Arguello field is one of the largest discoveries in U.S. (Outer Continental Shelf (OCS) history. Recoverable reserve estimates range from 400 to 500 million barrels, and combined field flow rates are projected to reach 160,000 barrels per day by the end of the century. In addition, total flow rates from the fields off Santa Barbara County are expected to reach 450,000 barrels per day by the early 1990s. The east Wilmington field further south in Long Beach produces 120,000 barrels per day. These three fields have the highest production rates in the lower 48 States.

West Coast drilling rates offshore are slow by comparison with the Gulf Coast. A typical offshore well requires 6 to 8 weeks to complete. Gravel packing is often necessary. If more than one reservoir is present at a drill site, the casing may be perforated to enable the wells to produce from multiple zones.

The low gravity, asphalt-base oil means that processing facilities are complex. This, coupled with the thick formations, makes the typical West Coast platforms larger than Gulf Coast platforms. Sixty-well platforms are common, and large expensive production facilities are the norm. It can be expected that this trend will continue in deep water.

Environmental Conditions

Important environmental parameters that affect the design of production platforms and systems are summarized in table 3-6 for the Atlantic, Gulf, and Pacific regions. These values are based on general industry practice. Conditions that are peculiar to a specific region are discussed below.

Table 3-6.—Deepwater Environmental Design Conditions

Region	Maximum wind velocity* • (knots) (1 hour duration)	Maximum 100 year wave height (feet)	Typical current velocity* (surface to 200 ft.) (knots)
Atlantic	90	85	3.0
Gulf	90	70	3.0
Pacific	60	60	2.0

“Exact value of current velocity varies and is highly dependent on precise location, particularly in the Atlantic and Gulf,

“ “For 10 meter elevation; higher elevations may be subject to higher velocities and gusts.

SOURCE: Office of Technology Assessment.

Atlantic

Hurricanes, other severe storms, and the Gulf Stream are major environmental factors in the Atlantic region. The Gulf Stream presents problems in both exploratory drilling and for production systems if commercial discoveries are in areas affected by its currents. The current velocity is up to 5 knots near the surface and in the range of 3 knots to a depth of more than 1,000 feet. This high current velocity may require streamlined risers for exploratory drilling and must be considered in the design of compliant structures if they are used. The major impact of the Gulf Stream is confined to the southern portion of the Atlantic region. The Mid-Atlantic a-rid North Atlantic areas are only slightly affected since they are not in the main stream of the current. However, warm core eddies may spin off the Gulf Stream and affect systems in these areas.

Seafloor instability, especially on the Continental Slope, may require that specific sites be avoided or that special foundation stabilization techniques be used and/or developed. Other environmental conditions in the Atlantic region generally are less severe than in the North Sea and more severe than in the Gulf of Mexico. The design methods, as well as the operational experience gained from the Gulf, probably can be upgraded to meet Atlantic development requirements.

Gulf of Mexico

Hurricanes are also a major environmental factor in the Gulf of Mexico. Industry has a great deal

Photo credit: Scripps Institution of Oceanography

Rough seas are an important environmental design condition in offshore frontier areas of experience in designing fixed offshore structures to withstand the high winds and waves generated by these intense storms, and this experience recently has been applied to Exxon's Platform Lena which is a compliant structure. Mud slides are another unusual environmental factor in the Gulf. These slides may cause foundation instability in some areas. Another factor is the Gulf of Mexico loop current and the eddies which are produced by that current. These eddies affect operational practices and the design of structures since they may cause vibrations which could lead to metal fatigue or other failures. Generally, in the Gulf, there is a wealth of experience to draw upon as development moves into deep water.

Pacific

The wind and wave conditions in the Pacific region are less severe than either the Atlantic or the Gulf of Mexico, but earthquakes area factor which must be considered in system designs. Design criteria and analytical methods have been developed for the entire West Coast, and these have been applied successfully to numerous offshore structures. Earthquakes should not pose serious problems for properly designed compliant structures since the natural vibration response periods of these structures are well outside the high energy portion of the earthquake spectrum. Soil characteristics must also be considered in system designs for the Pacific region because of the steep slopes present in some areas.

Technology Development

Exploratory Drilling

The offshore drilling industry currently has a fleet of 13 drillships and semi-submersibles capable of drilling in waters deeper than 3,000 feet. Of these, four drilling units are capable of drilling in 6,000 feet of water and one in 7,500 feet of water.

Several technical advances have made this deepwater capability possible. These include: 1) dynamic positioning utilizing controllable pitch thruster propulsion units and computerized automatic station-keeping systems (see figure 3-13); 2) reentry systems utilizing television and sonar instead of guidelines; 3) electrohydraulic blow out preventer control to reduce signal transit time; and 4) marine risers equipped with syntactic foam buoyancy material and improved riser couplings.[10]

Limitations to exploratory drilling in very deep water come primarily from environmental conditions and a low formation fracture gradient. Excessive current velocities (approximately 5 knots or greater) could prevent some dynamically positioned drilling units from maintaining their position because of the large amount of power required to counteract such forces. Also, wave heights exceeding 20 feet can interrupt drilling operations from a dynamically positioned drill ship. Some of these limitations may be overcome through the use of a dynamically positioned semi-submersible with substantially greater station-keeping capability than existing vessels. Abnormally high formation pressures, particularly at shallow formation depths, can also cause difficulty in deepwater drilling and could limit or prevent development of some deepwater reserves.

Field Development

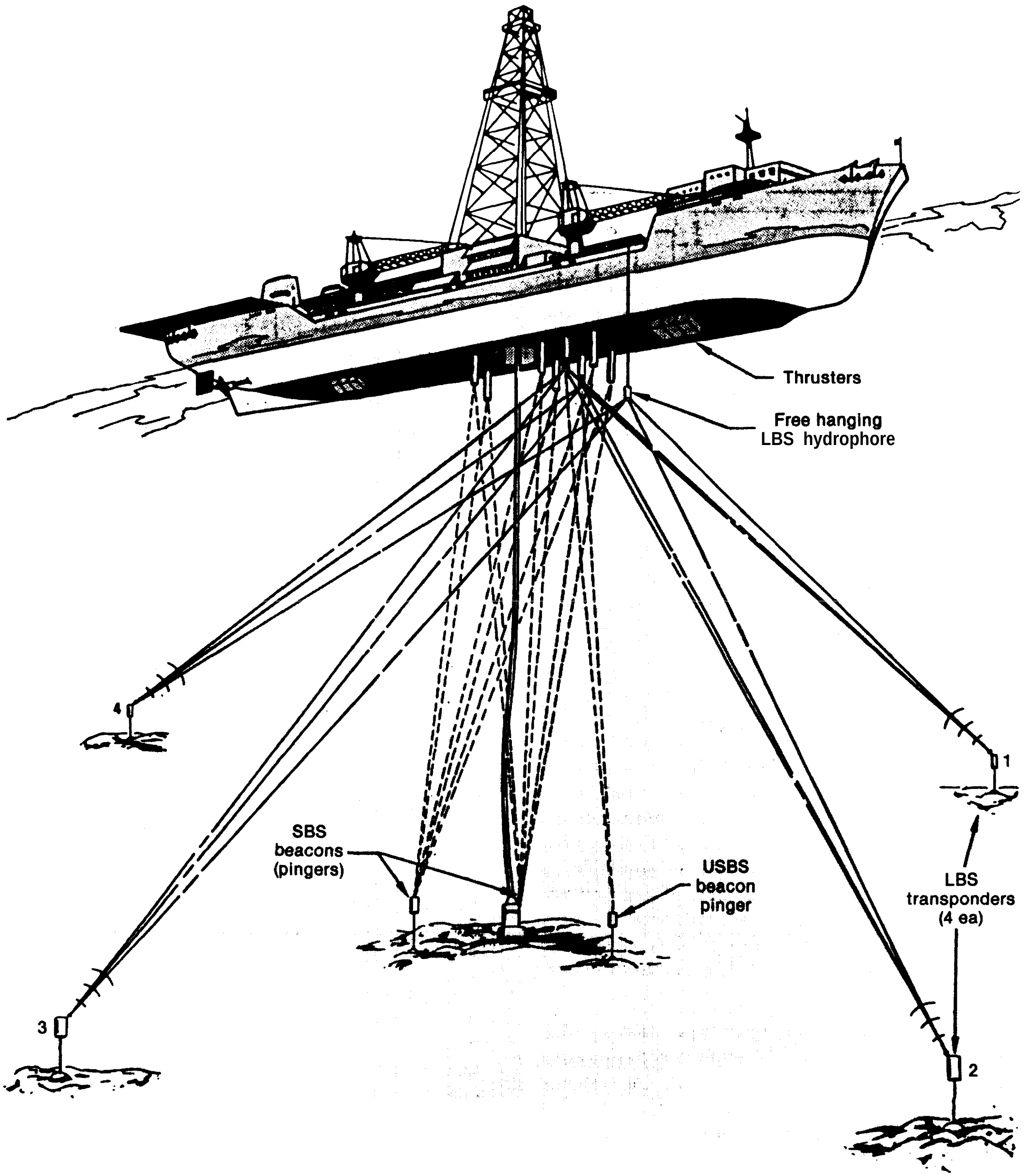
Nearly all offshore fields to date have been developed using fixed-leg platforms. During the 1970s, industry progressed from the capability to design and install fixed-leg platforms in about 400 feet of water to design and installation for the current record depth of 1,025 feet for Shell's Cognac platform in the Gulf of Mexico. Designs also have been completed by Exxon for a fixed-leg platform for installation in 1,200 feet of water in the Santa Barbara Channel. Technically, fixed-leg platforms can be built for a water depth of 1,575 feet or more. However, due to the large amount of steel required and limitations of fabrication and installation methods, there is probably an economic limit for these structures at a water depth of about 1,480 feet.[11]

There are several concepts for extending water depth at which production systems can be installed; for example, the guyed tower, the buoyant tower,

[10] A.S. Johnson and G, O. Smith, ' 'The Technology of Drilling in 7,500 Feet of Water' (Society of Petroleum Engineers, Paper 12793, 1984); and J. C. Albers, "Exploratory Drilling Systems" (Outer Continental Shelf Frontier Technology Symposium, 1979).

[1] IF. P. Dunn, ' 'Deep Water Drilling and Production Platforms in Non-Arctic Areas" (National Academy of Sciences, 1980); and R. L.Geer, " Engineering Challenges for Offshore Exploration and Production in the 1980s' (BOSS Conference, 1982).

Figure 3-13.—Dynamic Positioning for Deepwater Drilling



SOURCE: Proceedings of the Offshore Technology Conference, 1984 the tension leg platform, and the subsea production system. All but the subsea production systems are "compliant structures, which are designed to move slightly with environmental forces of wind, waves, and current as opposed to conventional structures which rigidly resist such loads.

The guyed tower is a tall, slender structure that requires less steel than a fixed-leg platform. Guy lines or anchor lines are used to resist lateral forces and to hold the structure in a nearly vertical position. Exxon has recently installed the first guyed tower, Lena, in 1,000 feet of water in the Gulf of Mexico. The platform, with space for 58 wells, is secured with 20 guy lines, eight main piles, and six perimeter torsion piles.[12] Current technical opinion is that guyed towers are structurally and economically feasible in water depths to about 2,500 feet. Beyond these water depths, the guyed towers will require much greater amounts of steel to maintain an acceptable stiffness.

The buoyant tower is a tall, slender structure like the guyed tower but is maintained in a vertical position by large buoyancy tanks rather than by guy lines. Rotation at the base is accounted for either by an articulated joint or by a flexible foundation.

The tension leg platform is a floating platform fixed by vertical tension legs to foundation templates on the ocean bottom. OTA has selected a tension leg platform for its hypothetical deepwater scenario (see box). Buoyancy is provided by the pontoons and columns of the hull. The buoyancy that is in excess of the platform weight maintains the legs in tension in all loading and environmental conditions. The floating hull of the tension leg platform, similar to that of a semi-submersible, is secured at each corner by a number of so-called tendons. The hull pulls upon the tendons so that they never go slack, even in the trough of the maximum design wave and when carrying maximum operating loads.

The substantial advantage of the tension leg platform is its relative low cost sensitivity to increases in water depth. The principal design influence of increasing water depth is in the tendon and riser lengths, with the hull size and weight increasing relatively slowly with water depth. The main disadvantages of a tension leg platform are the operational complexity of its well and tendon systems relative to fixed platforms and its limited deck load capacity.

The first tension leg platform was installed in 1984 by Conoco in 485 feet of water in the North Sea. This probably is not an economical water depth for a tension leg platform, but its installation in the North Sea will provide the experience and information needed to successfully install these units in deeper waters.

Practical application of tension leg platforms will start where it is no longer economically attractive to construct a fixed-leg platform. This water depth is estimated to be around 1,500 feet, depending on location. For intermediate depths of 1,000 to 2,500 feet, the guyed tower is thought to be the attractive alternative. Theoretical maximum water depths for tension leg platforms are estimated by Conoco to be 6,000 feet by the year 1990 and 10,000 feet by the year 2,000.

Subsea production systems are also a major alternative for deepwater field development. With these systems, wells are drilled from a floating rig and completed on the seafloor. Several such systems have been extensively tested in operations in shallow water. These include Exxon's system in the Gulf of Mexico (see figure 3-14), Hamilton's Argyll Field in the North Sea, and Shell/Esso's system in the Cormorant Field in the North Sea.

Currently, there are more than 100 offshore subsea well installations in operation in water depths of up to 960 feet. An additional 36 subsea well completions currently are scheduled for installation. *[13] One of these is a subsea well completion by Chevron offshore Spain in a water depth of 2,500 feet.

Subsea well completions can be either "wet' or "dry" systems. The wet system is relatively insensitive to water depth and can be installed in deepwater in the same manner as shallow water. Its application is limited only to the water depth capability of the floating drilling unit and the flowline installation technique, In the dry system, the well head

[12] P. H. Kelly, F. B. Plummer, and P. J. Pike, "The Lena Guyer Tower: A Pioneering Structure" (Proceedings of the DOT Conference, 1983).

[13] M. Tubb, " 1983 Subsea Completion Survey, " Ocean Industry (October 1983).

Deepwater *Technology* Scenario

To assess deepwater technology, OTA selected one hypothetical prospect located offshore the central California coast approximately 3$ miles west of Point Conception in water 3,000 to 4,100 feet deep. Assumptions about field conditions, exploration and development, infrastructure and support services, and transportation for this deepwater scenario are shown in the accompanying table. It should be noted that the assumptions made for this area are illustrative, and actual conditions may vary substantially. The oil accumulation could be deeper, the gravity of the crude could be sour, and well spacing might need to be closer. All of these factors would increase the cost of development and change the technical approaches chosen for this scenario.

Schedule

The schedule begins with the lease sale and ends with the completion of development drilling-a total of 13 to 14 years. First production is assumed to occur 10 years from the lease sale date. This schedule is probably optimistic because it assumes the minimum time to obtain the necessary governmental approvals. It also assumes that detailed design of the platform will begin at the time of discovery and proceed concurrently with permitting and approval. Timeframes would also increase if the area is more difficult to develop than postulated (e.g., heavier crude, sour crude, nonsircular field), or if two platforms are required instead of one.

Exploration and Development

Water depth in the scenario area is within present industry capabilities for exploration. Several dynamically positioned drilling units, ship-shape and semi-submersible, currently are able to drill exploratory wells in water depths of 6,000 to 7,500 feet. Drilling units of this type are equipped with computer controlled main propulsion and thruster units. The unit is kept on location by these thrusters with positioning data from a continuous acoustic signal emitted by one or more beacons located on the seafloor. The use of this dynamic positioning equiment has made these drilling units independent of the constraints imposed by a mooring system.

Development of a discovery in a water depth of 3,000 to 6,000 feet appears to be technically feasible but has not yet been achieved. Several development methods are possible, including tension leg platforms, floating production systems, and subsea production systems. The method selected for this scenario is the tension leg platform with surface completed wells. These have been designed for water depths up to 3,000 feet, but there has not yet been a commercial discovery in such depths. A subsea production system is an alternative for this scenario but most designs to date are not self-contained units; storage and processing facilities would be required on a separate platform. Satellite subsea wells oculd be used in conjunction with a tension leg platform especially with a more elongated field shape.

Sixty directional wells would be drilled from the tension leg platform and would have individual conductors from the ocean bottom to the lower deck for completion and hook-up in a manner similar to (although operationally more complex than) methods used for fixed, bottom-founded platforms. Alternative designs provide for incorporation of the conductors inside the mooring legs or for completing the wells on the seafloor. With the latter method, an ocean floor manifold would be required and one or two risers would bring oil to the surface.

Transportation and Infrastructure

For environmental reasons, California State prefers a subsea pipeline rather than shuttle tankers to transport crude oil to shore. Deepwater pipelaying capability has advanced to where the technology (but not the actual equipment) exists to install a 20-inch pipeline in water depths of 7,500 to 10,000 feet. However, actual experience has been limited to water depths of about 2,000 feet. A tensioned 20-inch pipeline riser would be installed between the ocean floor template and the deck of the tension leg platform. The pipeline would be connected to the riser through a pull-in assembly.

This scenario assumes that all production would be treated to pipeline quality on the platform, which would involve the installation of oil, gas, and water separation and treatment equipment onsite. An alternate approach is a joint industry trunkline carrying an oil-waste emulsion for treatment onshore, with the gas not used for fuel reinjected into the formation for pressure maintenance, and the water treated to EPA standards and discharged overboard.

Support of a single exploration and development operation in the central California offshore area would require at least one supply vessel, one crew boat, and one helicopter. The crew boat would also function as a standby boat, and would transport small supplies to the rig. The helicopter would be used for routine transportation of drilling crews and small supplies.

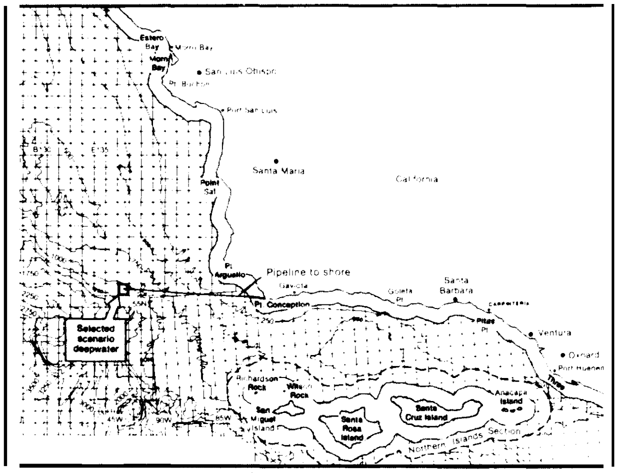
Deepwater Scenario

Parameters	Offshore California
Field conditions:	
Water depth	3,000 to 4,000 ft
Water depth at platform	3,300 ft
Distance from shore	80 mi
Top of producing zone	8,900 ft subsea
Producing zone thickness	800 ft
Type of crude	Sweet
Crude gravity	28° API
Gas-oil ratio	1,000
Exploration:	
Number of wells	6
Type of rig	Dynamically positioned drillship
Development:	
Type of platform	Tension leg platform[a]
Number of platforms	1
Number of rigs	2
Total number of wells	60 (directional)
Well spacing	80 ac
Maximum inclination	50°
Recoverable oil reserves	300 million barrels
Initial well production rate (B/D)	2,000
Peak field production rate (B/D)	70,000
Decline rate	10 percent
Infrastructure and support services:	
Support base	Port Hueneme, CA
Supply vessel	Standard 180 ft without anchor handling equipment
Crew boat	120 ft, operating out of Carpinteria, CA
Air service	Helicopter out of Santa Maria or Santa Barbara
Transportation:	
To shore	Subsea pipeline, 30 mi long, 20 in diameter[b]

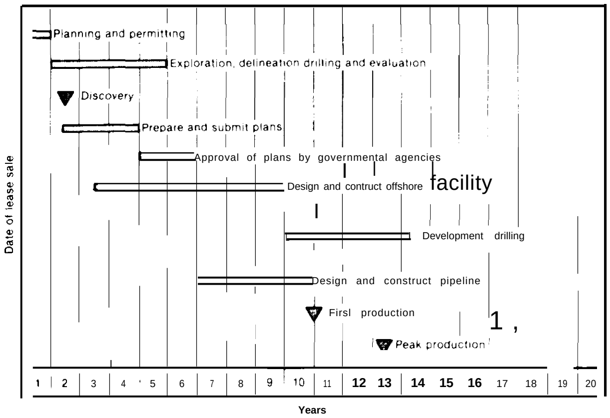
[a]Alternatives include floating production system and subsea production systems.
[b]Preferred for environmental reasons, alternative is shuttle tankers.

SOURCE: Office of Technology Assessment.

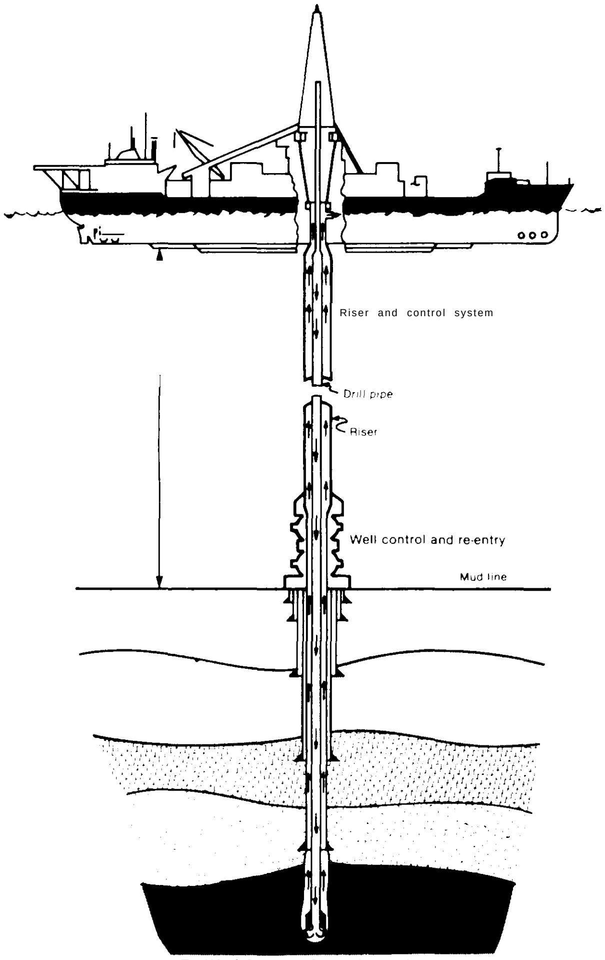
Deepwater Scenario
(Offshore California)



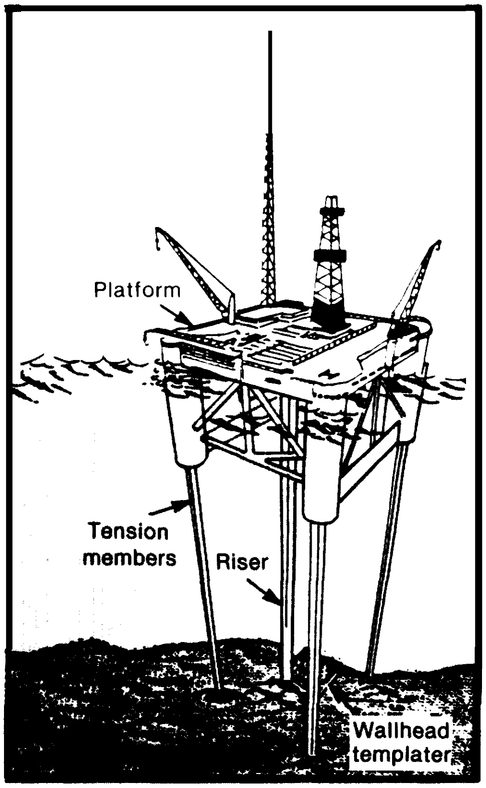
Location of discovery



Schedule

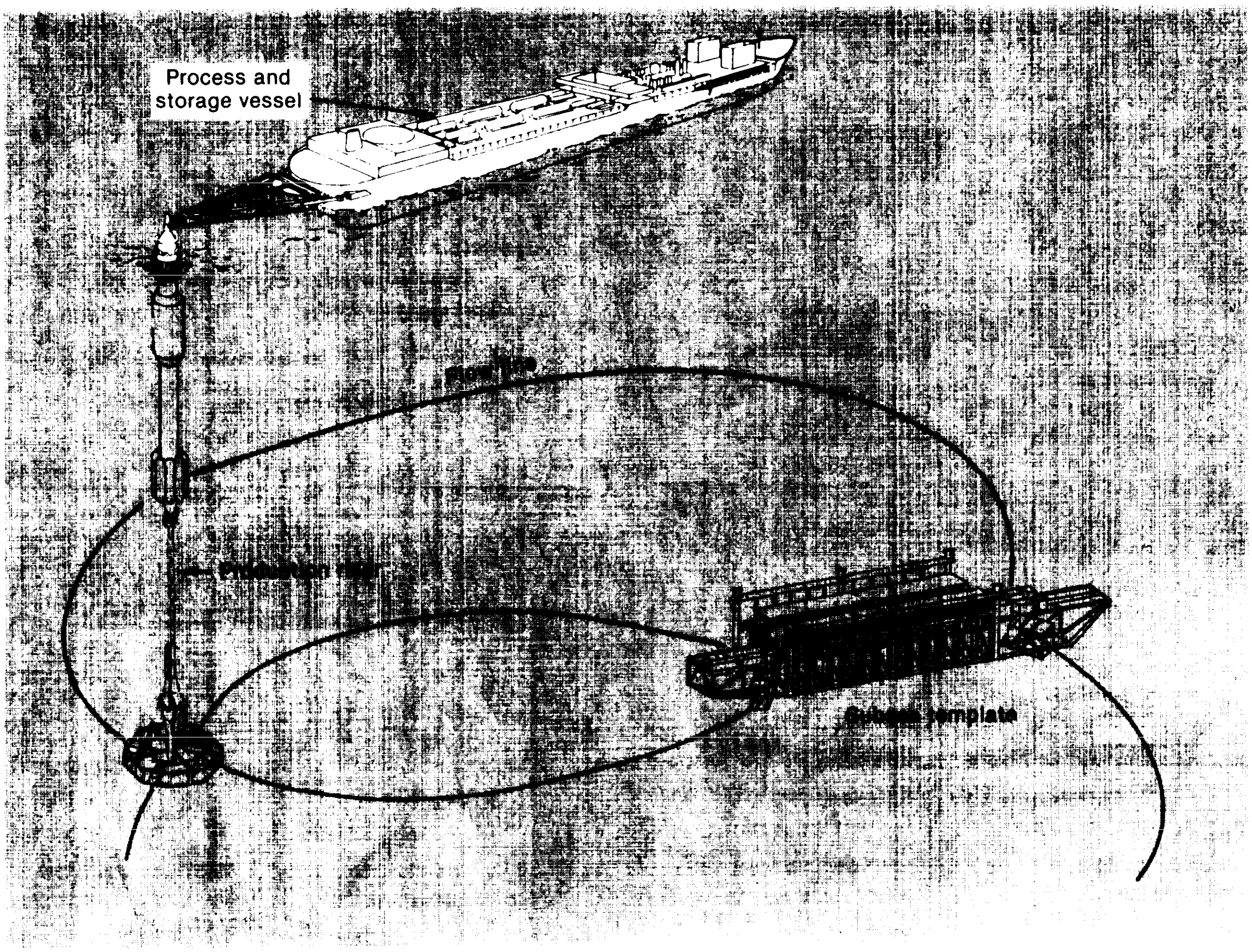


Drillship exploration rig



Tension leg production platform

Figure 3-14.—Subsea Production System



SOURCE: Exxon.

is housed in a dry, atmospheric chamber on the seafloor. Flowline connection and maintenance work can be performed by workmen inside the chamber in a normal atmospheric, shirt-sleeve environment. The workmen are transported to and from the chamber in a tethered, atmospheric diving bell which mates to the chamber allowing completely dry access for nondivers. Current development of subsea systems seems to favor the wet instead of the dry system.[14]

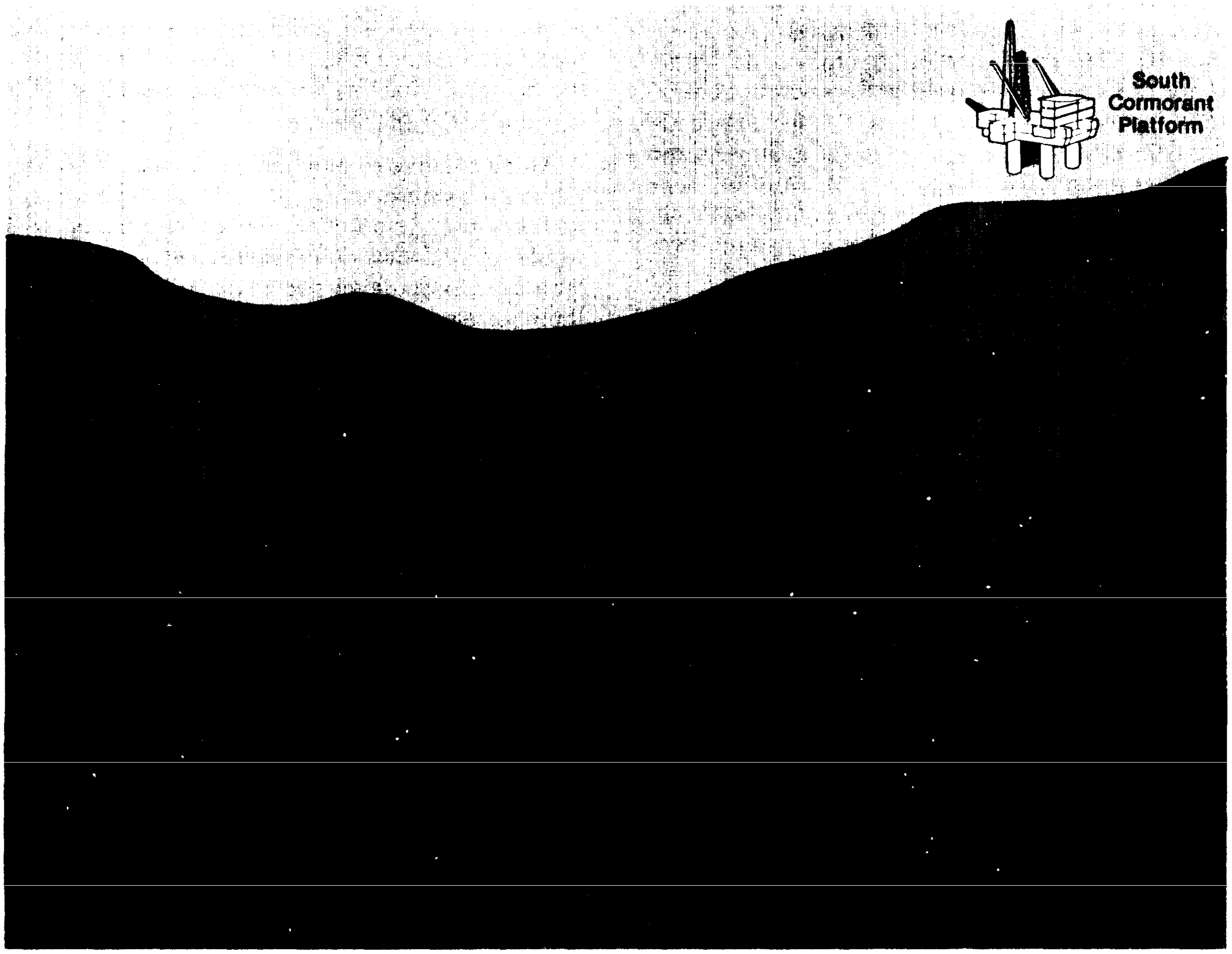
Most of the subsea installations are single well completions with the well producing through a flowline to shore or to a fixed or floating platform. In a few installations, the subsea wells are tied into an underwater manifold with a common production riser to a floating production unit. One such system is represented by Shell/Esso's Underwater Manifold Center recently installed in 500 feet of water in the North Sea (see figure 3-15). This system provides for a number of subsea wells clustered on an underwater template with associated manifolding and control equipment. Maintenance operations are performed with a remote vehicle connected to a production platform located several miles away.[15]

An inherent limitation of the subsea production system is the need to have surface facilities to proc-

[14] Robert C. Visser, "Deep Water Drilling and Production Capabilities, Department of Interior Hearing (May 1977).

[15] T. Bastiaanse and J. R. Liles, "Overview of the Central Cormorant Mannifold Centre Project (1974- 1983), Proceedings of the Offshore Technology Conference (1983).

Figure 3-15.—Underwater Production System



ess the oil and gas for transport to market. Additionally, all well work that cannot be handled by thru flow-line techniques requires an expensive, floating platform. Artificial lift to bring the product to the sea surface is complex and difficult to maintain with hydraulic or electric pumps. However, gas lifting is suitable for these subsea wells. The application of subsea production systems is expected to be more suited to the development of satellite reservoirs where oil can be routed to a preexisting platform.

One of the assumptions that was made for OTA's deepwater scenario was an essentially circular field. This enables the use of a single tension leg platform from which directional development wells can be drilled to fully develop the discovered reserves. In reality this is rarely the case and, particularly with a long and narrow field, it may be desirable to use subsea completed wells in conjunction with a tension leg platform. This approach may make it possible to more completely drain the reservoir and to develop a deepwater field more economically.

Transportation

Conventional pipelaying techniques such as the lay barge, reelship, surface tow, and bottom tow will require adaptation before they can be applied to deepwater situations such as those involved in offshore California. While deepwater pipelaying capabilities have improved considerably, driven particularly by the need to lay pipelines in deepwater areas of the Mediterranean, such techniques and required equipment are not fully developed, widely available, or in commercial demand. Semi-submersible, ship-shape, and more conventional barge-shape hulls have been used in the current generation of deepwater pipelay vessels. Other more advanced vessel designs are based on inclined ramp or J-curve methods as opposed to using the conventional "stinger. Bottom-tow or flotation techniques are also considered viable deepwater techniques. [16]

Pipelay capabilities have advanced considerably in order to deal with the specific problems attached to deepwater pipeline installations. These problem areas include: pipe failure due to propagating buckle phenomenon, longer unsupported span lengths, higher strain levels, more severe sea states, longer pipe exposure time during pipelays, and the need for greater accuracy in the control of vessel motions, new mooring techniques, and new classes of thicker diameter pipe.

In general, most of these problems have been successfully solved or are being solved through improved techniques, equipment modifications, or changes in basic technological applications. Vessels capable of laying pipe in deep water may now incorporate the following features: automatic position control systems; high tension capacity; advanced mooring systems; automatic welding, including single-station pipe joining or double joining capability; large pipe storage capacity; and use of computer simulations to optimize a pipelaying spread.

At the present time, it appears feasible that pipelines up to 20-inch (51 centimeters) diameter can be laid in water depths of 4,000 feet using existing or slightly modified equipment, although proven installation has taken place in only 2,000 feet. Saipem's dynamically positioned semi-submersible pipelayer Castoro SEI laid 3 20-inch lines across the Strait of Sicily in the Mediterranean in 1979 in waters to 2,000 feet.

An alternative to pipeline transportation of the crude oil to shore is the use of a floating storage and loading system from which shuttle tankers would move the crude to market. A variety of systems have been developed to provide floating offshore storage and/or treatment and loading systems for transferring oil to shuttle tankers. Offshore storage and loading systems were initially designed to allow continuous production in areas with severe weather conditions or with deep trenches inhibiting pipelines such as in the North Sea. These systems now have been greatly expanded or modified to aid in the use of subsea production systems, to allow marginal field development, and to initiate production from a field as early as possible.[17]

Floating ship-shape or semi-submersible production facilities and combined production/storage/loading facilities recently have become attractive to offshore operators. Floating production units are gaining acceptance by the oil industry as alternatives to fixed platforms for deepwater applications. Many floating systems are already in operation, mostly converted semi-submersible drilling rigs and tankers. State-of-the-art installations include Shell's multiwell floating production, storage, and offloading system for Tunisia's Tazerka field in 460 feet which is tied-in to subsea wells. No systems of this type are currently available for use in water depths in excess of about 3,000 feet.

[16] Dames & Moore, GMDI, and Belmar Engineering, "Deep Water Petroleum Exploration and Development in the California OCS, report prepared for the Minerals Management Service (January 1984).

[17] D. M. Coleman, "Offshore Storage, Tanker Loading, and Floating Facilities, Outer Continental Shelf Frontier Technology Symposium (1979); and "A Complete Producing System for Deep Water, Proceedings of the DOT Conference (1983).