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Summary

Congressional debate over opening the coastal plain of the Arctic National Wildlife Refuge (ANWR) on a portion of the North Slope of Alaska to petroleum exploration and development is under way in the 109th Congress. Current law prohibits such development in ANWR.

The North Slope is home to the two largest oil fields in North America and to the largest U.S. oil field discovered in the last decade. The North Slope also is home to a diverse, unique, and fragile ecosystem – resulting in extensive federal, state, and local regulatory protection. Partly due to increased restrictions since the discovery of Prudhoe Bay, operators have developed less environmentally intrusive ways to recover arctic oil, primarily through innovations in several types of technology.

Seismic technology offers the exploration sector advanced analytical methods that generate high resolution images of geologic structures and that help identify oil and gas accumulations by looking for anomalies or hydrocarbon indicators in the seismic data. Ice-based technology has been improved so as to better serve remote areas during exploratory drilling and production. Computers now allow the manipulation and interpretation of vast amounts of data, offering more precise well locations, thereby reducing the number of wells needed to find hydrocarbon accumulations.

Recent advances in drilling can reduce the footprint of petroleum operations in arctic environments. New drilling bit designs, fluid formulas, and advanced forms of drilling, such as extended reach, horizontal, and designer wells, permit drilling to reach as far as five miles from a wellhead location and to drill around geological barriers to find and develop hydrocarbon accumulations. Advances in drilling allow less space for a drilling rig, and reduce volumes and weights of both equipment and drilling waste.

Production facilities are now more compact, with modules performing many functions. A project goal of operators on the North Slope is zero discharge of solid and fluid wastes. Production drilling techniques using slim hole technology, such as coiled tubing and multilateral drilling, can contribute to smaller footprints, less waste, and better recovery of hydrocarbons from each well.

Proponents of opening ANWR to energy development maintain that these technologies substantially mitigate the effects on the environment of oil and gas operations, and assert that the increase in domestically-produced energy would be worth any minimal environmental impacts. Opponents counter that a facility of any size would still be an industrial site and an intrusion on the ecosystem, and argue that the need for gravel and scarce water, the permanent roads, ports, and airstrips that would follow, and the unknown number of spills would destroy vegetation, contaminate water resources, and interfere with wildlife.

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Introduction and Overview

Background and Scope

Congressional concern over high oil prices, growing U.S. dependence on oil imports, budgetary pressures, and maintenance of the Alaskan oil infrastructure has revived discussion over possibly opening part of the Arctic National Wildlife Refuge (ANWR) to oil and gas exploration and development. That part is a 1.5-million-acre area called the "coastal plain"—the so-called 1002 area. Among the arguments put forward by proponents of opening ANWR is that there would be a much smaller surface impact, or footprint, from the petroleum industry's presence compared with procedures, operations, and equipment discussed in the 1987 Final Legislative Environmental Impact Statement (FLEIS) on the Refuge prepared by the Department of the Interior.[1] Current law prohibits petroleum and gas development in ANWR.

Some environmental impact is unavoidable with industry activity. Searching for oil and gas involves drilling into the earth with heavy equipment; and various facilities and other activities are necessary to support such drilling. The downscaling of petroleum equipment and operations and the advanced technological solutions to exploration, drilling, and production difficulties have reduced these impacts, however. Improved exploration and development technologies that have become more widely available include advanced seismic data analysis, ice-based technology, slim hole and high performance drilling techniques, and methods to reduce waste.

Such innovation also is a factor in addressing the economic obstacles to finding and developing hydrocarbons. Technological advance has more than doubled exploration success rates and markedly improved drilling and production performance and efficiency. Petroleum industry worker productivity has increased[2] and the industry indicates that the potential impact of oil and gas operations on the arctic environment has decreased.[3]

Of course, use of the new technologies in ANWR or elsewhere significantly depends upon the nature of the requirements for exploration, development, and production, and on oil prices.

The policy issue of whether ANWR should or should not be opened to oil and gas development is not addressed in this report. For more information on ANWR controversies and legislation, see CRS Issue Brief IB10136, *Arctic National Wildlife Refuge (ANWR): Controversies for the 109th Congress.* Similarly, the report does not discuss in detail possible effects on the biological environment of industry operations, or the use of the new technologies in light of regulatory requirements for pipeline construction, spill containment, and reclamation of exploration and production sites.[4] Discussion and analysis of some of these matters can be found in CRS Report

[1] U.S. Dept. of the Interior, Fish and Wildlife Service, U.S. Geological Survey, and Bureau of Land Management, *Arctic National Wildlife Refuge, Alaska, Coastal Plain Resource Assessment,* Report and Recommendation to the Congress of the United States and Final Legislative Environmental Impact Statement (Washington, DC: 1987), 208 p.

[2] U.S. Dept. Of Labor, Bureau of Labor Statistics. "Industry Productivity and Costs," data/bls.gov/PDQ/servlet/SurveyOutputServlet viewed on February 27, 2005.

[3] See description of the Alpine field on page 6.

[4] Because most fields discovered on the North Slope are still producing, there is limited experience with restoration measures. However, reclamation sites are being identified and procedures, such as use of microorganisms and plants for cleanup, are being investigated.

RL31278, *Arctic National Wildlife Refuge: Background and Issues*, by (name redacted) et al. However, to put the technology developments—the focus of this report—in perspective, the report's initial section summarizes some of the concerns expressed by opponents of development in the Arctic National Wildlife Refuge, as well as some of the benefits of ANWR development offered by proponents.

Exploration and drilling technologies are discussed next, as exploration is the first step toward commercial production of hydrocarbons. After successful drilling of an exploration well or wells, there are a variety of technological options available to the industry for starting the development of the discovery. Production technologies that make it possible to effectively recover the hydrocarbons will complete the technology discussion. The report also compares the procedures and potential environmental effects described in the 1987 FLEIS report with today's available procedures and their possible impacts.

Potential Issues

While it can be reasonably argued that advanced arctic petroleum technologies substantially mitigate the environmental impact of oil and gas operations compared with how North Slope Alaska oil was developed originally, it also is contended that the use of natural resources such as gravel and water, the probability of spills, and the loss of wilderness as a result of human intrusion are issues that technology advances cannot address.

Gravel would be used in development of the 1002 area—at least for things such as main pads, airstrips, and connecting roads. Mining the gravel might result in local changes in topography; roads may have to be built to transport the gravel to exploration and production sites; and there would be a direct loss of coastal plain habitat due to secondary effects of gravel spray, dust deposition, and altered snow melt and erosion patterns stemming from facility construction and gravel mining. Very large quantities of water will have to be used for various activities, such as drilling, ice road and ice pad construction, and support of camp facilities, including human consumption. Water probably would have to be transported into the area.

The long-term effects of winter exploration, drilling, and production operations are unknown. Summer erosion and melting of permafrost may due to the heat generated near productions sites. Tundra may be destroyed around the perimeter of insulated ice pads. Compaction, destruction, and delayed growth of vegetation may occur around ice pad production sites. And even minor spills may cause some destruction of vegetation, contamination of waters, and mortality of small food organisms. Surface disturbances probably would be numerous, with production facilities connected by a gathering network or a system of pipelines to an existing or a future pipeline; and production and related equipment may have to be staged at another location over the summer months, then transported to the field during the winter. The use of ice roads may be limited by hilly topography.

On the other hand, oil and gas development of the Refuge, it is argued, could yield possibly significant gains in energy security and economic benefits. Development supporters contend that ANWR oil would reduce U.S. dependency upon foreign petroleum, create jobs in Alaska and elsewhere in the United States, generate tax revenues, extend the economic life of the Trans Alaska Pipeline System, and possibly lower oil prices. These potential benefits are discussed and analyzed at length in CRS Report RL31278, *Arctic National Wildlife Refuge: Background and Issues*, by (name redacted) et al., and in CRS Report RS21030,*ANWR Development: Economic Impacts*, by (name redacted) .

Status of Exploration, Drilling, and Production Options

The petroleum industry has accelerated the introduction and use of new technology for operations in the harsh Arctic environment since 1987, the year the Department of the Interior released the FLEIS with its recommendation to drill in ANWR. **Tables 1 and 2** summarize the increasing availability of these technological changes since 1987. Some technologies are reported to have gone from the embryonic stage to the mature stage. Interim stages indicate that technology is characterized by a continuum of application and integration by the industry. Four of the now mature technologies were in early stages of commercialization in 1987.

Embryonic and emerging technologies are those first supported by scientific fundamentals and theory, and then introduced to industry as technology. Transfer to and initial testing of the technology by industry characterizes a growth technology. As the technology is used, it may or may not prove to be successful to the industry. If the technology is successful, repeated use establishes a track record. In the appropriate situations, mature technologies become common operating procedures.

New exploration technologies (**Table 1**) give petroleum geologists a clearer picture of underground structures and fluids before drilling begins, and thus reduce the need for exploratory drilling. The use of ice roads during the winter and insulated ice pads during the summer can reduce surface disturbance, and high performance drilling can reduce surface footprint of industry operations and waste generation.

Table 1. Exploration and Drilling Technology

Technology	Status in 1987	Status in 2005	Improvement
Determination of Structure and Fluid			
Advanced 2-D seismic data	Mature	Mature	Fewer dry wells
3-D offshore seismic data	Growth	Mature	Fewer wells or dry wells
3-D land seismic data	Emerging	Track Record	Fewer wells or dry wells
Determination of Fluid			
Advanced seismic modeling	Emerging	Mature	Fewer wells
Determination of Reservoir and Source			
Advanced geological modeling	Emerging	Track Record	Fewer wells and less waste
Data acquisition by satellites	Emerging	Track Record	Fewer wells and less waste
Ice-Based Technology			
Ice roads	Growth	Mature	Roads thaw in the summer, avoiding permanent damage to tundra; less movement of equipment
Insulated ice pads	Embryonic	Mature	
Advanced Drilling Technology			
High performance drilling	Growth	Mature	Site size for drilling 25% smaller (e.g., 65 acres at Prudhoe, 8.7 at Kuparuk); gravel surface area for production pads cut 76%.

Production technology that is more available than in 1987 (**Table 2**) requires fewer workers, less land, and less waste than earlier production methods. Subsequent sections discuss all of these technologies in greater detail.

Table 2. Production Technology

Technology	Status in 1987	Status in 2005	Improvement
Compact facilities	Embryonic	Mature	Controlled remotely with fewer people, less land, and modules can be reused
Zero discharge of solid and fluid wastes	Emerging	Mature	No reserve pits; 95% recycling of all associated wastes (office wastes)
Slim Hole drilling	Embryonic	Mature	Equipment is smaller and less waste is generated
Improved production drilling	Growth	Mature	Fewer wells, smaller units, less use of drilling fluids, and less drilling waste generated
Advanced production drilling	Embryonic	Growth	Smaller drilling units

Note: Sources for Tables 1 and 2: Discussion in the text.

History of North Slope Petroleum Activities

The North Slope is home to the two largest developed oil fields in North America; and it has the largest oil field discovered in the United States in the last decade. Logistical barriers posed by harsh environmental conditions—such as extremely low temperatures, freezing and thawing of the tundra, and remoteness—have limited but not prevented exploration, drilling, and production in this region.

Evolution of the Oil Industry on the North Slope

There has been interest in and geological exploration of the petroleum potential of the 65,000-square-mile North Slope coastal plain—11% of the land area of the state of Alaska—since about 1906. Federal exploration of the North Slope can be documented for 50 of the last 80 years, beginning in 1923; and industry exploration has been continuous since 1958.[5] A description of the exploration that has taken place within ANWR in particular is presented in the appendix to this report.

The possibility of petroleum in the subsurface was hinted at by the presence of oil seeps and oil-stained rock at the surface. Mining claims were staked on the seeps outside of ANWR in the early 1900s but never fully exploited. Oil seeps and oil-stained rock also were found within the coastal plain of ANWR. From 1944 to 1953, the Navy conducted a program in the Naval Petroleum Reserve #4, now the National Petroleum Reserve-Alaska (NPRA). There, 37 wells were drilled to test 18 structure types that appeared prospective for hydrocarbon accumulation. Three oil and

[5] For maps of the North Slope areas under discussion, see http://www.wilderness.org/images/images-other/map_AK_NS_leases.jpg, and Fig. 1.1.1-1, and Fig. 2.4.6-1 in the Final Alpine Satellite Development Plan Environmental Impact Statement EIS, found at http://www.alpine-satellites-eis.com/alpeis.nsf on Feb. 15, 2005.

seven natural gas fields, all uneconomic, were discovered.[6] Although uneconomic quantities of petroleum were found, this federal exploration program supported the conclusion that the North Slope had most of the elements of a major petroleum province. The information from the federal exploration program combined with subsequent economic studies indicated that profitable operations could be conducted on the slope despite the remoteness and harshness of the area, and several companies began North Slope exploration in 1958.

Three fields illustrate different methods of exploration and development in the Arctic environment. Prudhoe Bay, discovered in 1968 with production starting in 1977, Kuparuk River, discovered in 1969 with production beginning in 1981, and Alpine, discovered in 1994 and placed into production in 2000.

Prudhoe Bay Field

Prudhoe Bay is the largest known oil field in North America. In 1968, reserves were estimated at 9.6 billion barrels of oil and 29 trillion cubic feet of natural gas.[7] With advanced technology, estimated original reserves of oil (taking into account past production) have increased to14 billion barrels.[8] With no current economic means of getting the natural gas to markets, there has been little or no incentive to produce gas or pursue reserve estimation.

The subsurface hydrocarbon accumulation at Prudhoe Bay spans 125,000 acres. Six central production facilities (CPF) are used to separate oil from the gas and water. Extensive gravel roads branching off of a main gravel road 30 miles long and 30 feet wide connect the various development well pads. Waste treatment facilities and an airstrip are included at the main operations center. A central power station running on natural gas from the field provides all power to the facility.

Between 1977 and 1987, the field produced about 1.5 million barrels a day of oil. All wells were vertical or directional wells. Production began to decline in 1989, and the field was producing only about 680,000 barrels per day by early 1999. In anticipation of the decline in production, the first production horizontal well was drilled in November 1985. Horizontal wells generally have higher production rates and produce greater quantities of oil and gas than conventional wells because the well encounters more of the reservoir rock. Exploration is still occurring around the Prudhoe Bay field, with exploratory wells drilled each year to test outlying potential petroleum accumulations. Production from North Slope and fields in southwest Alaska, once about two million barrels per day, now is about 900,000 barrels per day.

Kuparuk River Field

The second largest producing oil field in the United States, the Kuparuk River unit (with satellite fields) is estimated to have had 2.9 billion barrels of reserves. It was deemed economic for

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[6] Morgridge, Dean L. and William B. Smith, Jr., Geology and Discovery of Prudhoe Bay Field, Eastern Arctic Slope, Alaska in Stratigraphic Oil and Gas Fields – Classification, Exploration Methods, and Case Histories," American Association of Geologists Memoir 16 (1972), p. 489-501.

[7] U.S. Dept. of Energy, *Alaska Oil and Gas: Energy Wealth or Vanishing Opportunity?* (Jan. 1991), pp. 2-8.

[8] Alaska Dept. of Natural Resources, Division of Oil & Gas, *2004 Annual Report* (Dec. 2004), Section IV, Table IV.1. (Hereafter referred to as Alaska DNR, *2004 Annual Report.*)

development in 1977 after completion of the Trans Alaskan Pipeline. It is producing about 160,000 barrels per day, with estimated remaining reserves of 1.0 billion barrels.[9]

About 2,000 wells have been drilled to fully develop the Kuparuk River field; all are directional or horizontal. Kuparuk's three major field installations are central production facilities, which include a water desalinization plant for use in production. The salt is mixed with water that is produced during oil production, and this mixture is injected into appropriate zones in the subsurface. Project goals were to reduce costs and to reduce the environmental impact of industry activities. The landfill for Kuparuk-associated solid wastes is 50 miles away, and hazardous wastes initially were shipped 2,000 miles. Advances in recycling and a 95% reduction in construction and waste material at Kuparuk River won the U.S. Environmental Protection Agency's (EPA) Evergreen Award for Pollution Prevention in 1999.[10]

Alpine Field

Alpine field, with initial reserve estimates of 365 million barrels of oil, was discovered in 1994, but not declared commercial until October 1996 after field work and delineation drilling were completed. The delineation effort included six wells, all drilled in the winter. Reserve estimates increased to 429 million barrels of oil as a result of data from the wells and a 3-D seismic survey. With the increase in the estimated size of the reserves, 112 horizontal wells instead of 94 conventional and directional wells were used to develop the field. Alpine started producing approximately 40,000 to 50,000 barrels of oil per day in November 2000.

During construction of the two drilling pad sites, equipment (e.g., 4,800-ton modules used for living quarters, power plants, and processing facilities) was stored at the Kuparuk River field during the spring and summer, then moved to the Alpine site by ice roads during the winter. The ice roads melted during the spring and summer months with no evidence of long-term damage to the tundra.[11] The drilling pad sites and the central processing facilities are on two gravel pads linked by a gravel runway/road. Operations at Alpine are similar to the operations on an offshore platform for the warmer summer months of the year. More than 350 truckloads of equipment are pre-positioned at Kuparuk River field during the winter months to make Alpine self-sufficient. Drilling solids and fluids and other waste are ground up, mixed with water, and injected underground.

Now operated by ConocoPhillips, the field has continued to be actively developed, with production rising to an average of about 120,000 barrels per day in January 2005.[12] In December 2004, the Bureau of Land Management and the Corps of Engineers approved development of two satellite drill sites containing five drill pads. About 28 miles of gravel roads will be added to the existing three miles of roads to allow movement of equipment, supplies, and personnel.

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[9] Alaska DNR, *2004 Annual Report*, Tables IV-1 and IV-3. The 2005 report was not available at this writing.

[10] U.S. Environmental Protection Agency, Region 10, "1999 Evergreen Award for Pollution Prevention, ARCO Alaska - Kuparuk River Oil Field," *Environmental Fact Sheet*, (Nov. 1999).

[11] Beez Hazen, Northern Engineering & Scientific, "Use of Ice Roads and Ice Pads for Alaskan Arctic Oil Exploration Projects," *NPR-A Symposium Proceedings* (Anchorage, AK: Apr. 1997) http://aurora.ak.blm.gov/npra/sympos/html/paper3.html, viewed Jan. 10, 2005.

[12] Kristin Nelson. "Alpine field hits one-day production of 128,363 bpd," *Petroleum News*, week of February 6, 2005.

Exploration and Drilling: Lower-Impact Approaches

Overview

Petroleum exploration starts with interpretation of geological and geophysical data to predict hydrocarbon potential. The different possible interpretations of that data lead to an estimate of the geologic risk. Then, the economic implications of these interpretations, the economic risk, is evaluated by the company and an overall risk is estimated before it is decided to drill an exploratory well.

Advanced techniques in seismic data interpretation allow a geophysicist to "see" and to interpret the likely presence of hydrocarbons thousands of feet below the surface. These highly quantitative techniques use advanced mathematical modeling. With the technology available to them, they work toward avoiding the costs (and environmental damages) of unnecessary wells during exploration for and production of hydrocarbon fields.

The use of advanced exploration techniques has contributed to the more than doubling of exploration success—the percentage of new field wildcat wells drilled that find any amount of hydrocarbons—since the 1980s.[13] Higher success rates mean fewer wells drilled, and because there are fewer wells, there may be less impact on the environment. However, especially in sparsely explored regions, exploration carries a high risk of dry holes despite the advanced techniques. The process of evaluating exploration is important because the most probable outcome of an exploratory well is a well without sufficient quantities of economically recoverable hydrocarbons. Quantifying this risk is a fundamental part of the petroleum business.

There are three common factors in ascertaining geologic risk. For petroleum to be present, a *structure* is needed to concentrate hydrocarbons; *reservoir rock* is needed to hold hydrocarbons; and *source rock* is needed to form hydrocarbons. Geologists and geophysicists try to determine if these three factors are present. If hydrocarbons are thought to occur in sufficient quantities, an exploratory well may be justified.

The advanced techniques used to identify and characterize the geologic and geophysical opportunities for commercial quantities of petroleum are described below. These techniques help improve predictions of the potential for the presence of the three factors: *structure*, *reservoir*, and *source*.

Exploration Methods

Exploration is the prospecting for accumulations of resources, but because it goes beyond discovery in extending the known limits of the accumulation, it is a much broader term than prospecting. Today, the oil and gas success rate in areas with little data is 20%-25%, but historically, that success rate has been 10%.[14] This increase in the success rate is due to advanced

[13] The success ratio of new-field wildcat wells in 2004 was 47.5%, compared with an average of 17.9% in 1980 to 1982. American Petroleum Institute. *Basic Petroleum Data Book*, August 2005, Section III, Table 1.

[14] Anthony B. Hayward, "Exploration Frontiers for New Century Determined by Technology, Politics," *Oil and Gas Journal* (Dec. 13, 1999), pp. 42-44; Charles Stabell and Norman Sheehan, "Competitive Advantage in Petroleum Exploration," *Oil and Gas Journal* (Apr. 23, 2001), pp. 30-35.

technologies that have improved the mapping of structure and identification of reservoir rock and has improved the determination of finding hydrocarbons.

State of the Art for Determining Structure

Seismic data, either two dimensional (2-D) or three dimensional (3-D), are the data most geophysicists in petroleum companies use to interpret the subsurface structure and fluid type of potential reservoirs.

2-D Seismic Data

Seismic data have been extensively used since the mid-1940s, when large-scale marine surveying was first done by the industry. Today, improved 2-D seismic data acquisition and interpretation techniques more accurately identify subsurface features or structures. Data resolution resulting from better designed seismic surveys and better models that interpret data make 2-D seismic data viable in areas with little data and limited access. Today, almost all companies rely on 2-D seismic for interpreting structure and for selection of exploratory well sites.

3-D Seismic Data

The first offshore 3-D seismic survey was acquired and interpreted in 1975-1976, and, since then, the application of 3-D seismic techniques has significantly improved success rates. Success rates as high as 47% to 70% have been recorded in offshore areas.[15] The use of 3-D seismic data on land and in areas with little data is growing, and the appropriate application of land 3-D seismic data may lower exploration costs and improve data accuracy.

Costs have been lowered in offshore 3-D seismic acquisition, but costs on land are up to 75% higher. Initially too expensive for small independent operators, 3-D seismic data in offshore areas are now routinely used by independent operators in the offshore areas of the United States and Europe. In 1989, only 5% of the wells in the Gulf of Mexico were based on 3-D seismic data, and the cost for a 50-square-mile survey was $8.0 million. For the same 50-square-mile survey, the cost was reduced to $90,000 in 2000.[16] 3-D seismic surveys require more seismic crew members at the survey site; consequently, 3-D seismic is more expensive and disruptive to the environment than 2-D.

Data Acquisition and Interpretation

Difficulties in onshore seismic acquisition and interpretation include ownership of the surface rights, physical and geomorphological barriers, and difficulties in interpreting the data as a result of attenuation or weakening of the data because the sound signal can be absorbed by the upper

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[15] E. O. Nestvold, "Overview – The Impact of 3-D seismic data on exploration, field development, and production," *SEG Geophysical Developments Series*, No. 5, American Association of Petroleum Geologists and the Society of Exploration Geophysicists (1995), pp. 1-5.

[16] U.S. Dept. of Energy, Office of Fossil Energy, *Environmental Benefits of Advanced Oil and Gas Exploration and Production Technology* (Oct. 1999). (Hereafter cited to as DOE, *Environmental Benefits of Advanced Oil and Gas Technology*.)

layers of the Earth and is converted to heat instead of an echo. In Alaska, 3-D seismic surveys have been acquired in the NPRA and in areas surrounding the producing fields on state lands.

2-D and 3-D seismic interpretations, however, are indirect exploration methods, because seismic work results in the mapping of structure in the units of time that it takes the sound echo to reach the surface. Converting the time recorded to the depth from which that echo is generated involves integrating geological data from wells, if available, and advanced processing and mathematical modeling. Characterizing the type and properties of the reservoir rock and identifying fluid type, such as oil or gas, is improving, but seismic data cannot yet routinely determine if a rock is a source of petroleum.[17]

Recent advances in interpreting seismic data in permafrost regions enable the use of winter-acquired seismic data. 3-D seismic acquisition in the 1002 area[18] of ANWR (see **Figure 2**) would not be hindered by ownership conflicts in many cases, as most surface rights are owned by the federal and state governments. In addition, northwestern ANWR is relatively flat with very few physical barriers.

State of the Art for Determining Type of Fluid

Seismic data not only are used to interpret subsurface structures that have the potential to contain hydrocarbons, but the technique also is routinely used to identify and estimate the amount of hydrocarbons contained in reservoir rock.

Advanced Seismic Modeling

Acoustic waves or energy are sent through the subsurface and the echos generated from rock intervals have velocities that are interpreted from the seismic data. These velocities depend on the rock properties and the type of hydrocarbon that fills the holes in the reservoir rocks. Gas and oil generate different velocities that generally have a specific amplitude. The amplitudes generated from a given fluid will have different strengths and can be used as hydrocarbon indicators (HI). HI can be detected in both 2-D and 3-D seismic data, and can identify the type of fluid present. In addition, HI are used to predict the thickness of the reservoir and hydrocarbon volumes.

In unexplored regions, identifying a hydrocarbon may be difficult because of uncertainty of the significance of the echo velocities. Well data increase the knowledge of the velocity differences of various rocks, and HI analysis may be used with high degrees of success. HI analysis is commonly used in areas that have high-resolution 2-D or 3-D seismic data to indicate the presence of petroleum.

Analysis of ANWR Oil Seeps: Oil seep data together with advanced modeling techniques can ascertain the possibility of finding just oil, just natural gas, or both oil and natural gas. Oils that have naturally risen to the surface (oil seeps) in the 1002 area have been analyzed and suggest that one rock formation is the most likely source for oil in the 1002 area. However, none of the

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[17] John T. Smith. "Petroleum system logic as an exploration tool in a frontier setting," *The Petroleum System - From Source to Trap*, L.B. Magoon and W.G. Dow, eds., American Association of Petroleum Geologists Memoir 60 (1994), pp. 25-49. This article also describes the methodologies for determining the possibility of a source rock in a basin.

[18] This portion of ANWR is named after §1002 in the Alaska National Interest Lands Conservation Act (ANILCA, P.L. 96-487); the section required a study of the area.

oils sampled at the surface is similar to Prudhoe Bay oil. This formation is capable of generating oil and gas or just gas, depending upon the depth to which it has been buried by younger rocks. The best technology to use in exploration may be determined by the type of hydrocarbon.[19]

State of the Art for Determining Reservoir and Source

Advanced geological models and satellite data provide geologists with improved techniques with which to interpret data more completely and to reduce the number of exploratory wells that may have to be drilled to find hydrocarbon accumulations.

Geologic Models

Geologic models, with the input of data from exploratory wells, have improved the accuracy of predicting the distribution and types of reservoir and source rocks in a given area. In addition, these models are used to convey reservoir rock properties to engineers and geophysicists during field development. Advances have been made in: computer power, speed, and accuracy; remote sensing via airplanes and satellites; image-processing technology; and satellite gravity and radar data. These technologies help geologists interpret surface and subsurface data more completely; manage, visualize and evaluate larger volumes of data simultaneously; and more accurately communicate the interpretations. The tools commonly used today are global positioning systems (GPS), which accurately locate data points, and geographical information systems (GIS), which manipulate and display the data.

Satellite Data

Optical satellite imagery has been the dominant source of data for identifying and mapping onshore geology since 1970, when the first Landsat satellite was launched. Satellites can now “see” up to 20 feet below the surface of the Earth. Additionally, early satellites required visible or near-infrared light to collect data. Now, radar satellites emit energy at microwave frequencies, enabling them to acquire data under any atmospheric condition. Interpretation of light frequencies from the surface of the Earth as measured by satellites may indicate oil seeps and oil and natural gas seepage over undrilled hydrocarbon traps.

Ice-based Technology

Ice-based technologies have reduced the need for permanent gravel roads in the Arctic to move equipment and have allowed industry to conduct seismic operations and to drill exploration wells in the winter with reduced impact on the physical environment. Ice technologies substantially reduce the need for gravel structures (with their high and long-lasting environmental impacts) at the exploration phase, and may offer some advantages in the development and production phases as well. However, use of ice technologies is constrained by the availability of fresh water, hilly terrain, and rising winter temperatures.

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[19] Anders, Donald E., Leslie B. Magoon, and Sister Carlos Lubeck. “Geochemistry of Surface Oil Shows and Potential Source Rocks,” in *Petroleum Geology of the Northern part of the Arctic National Wildlife Refuge, Northeastern Alaska*, Kenneth J. Bird and Leslie B. Magoon, eds. U.S. Geological Survey Bulletin 1778, 1987.

Ice Roads

Ice road construction begins with the use of vehicles, called Rolligons, with huge tires (and very low pressure on the ground) to transport and stage equipment. Rolligons compact the ice crystals as they travel over the surface of the frozen tundra, removing air and promoting further freezing of the ice. Snow (collected along temporary snow fences) and fresh water are added to the surface to increase the thickness of the ice. Also, ice chips are trimmed from frozen lakes to increase the road thickness. A warming trend over the last 30 years has delayed the start of ice road construction from mid-November to, usually, mid- or late December.

Insulated Ice Pads

Changing climatic conditions that have shortened the time available for exploration have resulted in widespread use of insulated ice pads. Drilling an exploratory well to 10,000 feet takes 90 to 140 days if no problems arise. Problems can seriously delay exploration, as equipment may have to be demobilized and transported to a storage area; and drilling operations would have to be completed the following winter. Higher average temperatures from the Fall to the Spring on the North Slope have restricted exploratory operations from over 200 days in the early 1970s to 75 to 110 days in recent years. Because of the economic and environmental effects of short drilling seasons, industry attention in the 1990s focused on lengthening drilling seasons—primarily through the use of insulated pads. A drilling site is selected, a pad of ice is constructed toward the end of the winter and covered with insulation over the summer months. Insulated ice pads about 400 feet by 300 feet can be covered with wind-resistant insulating panels to preserve the drill pad through the summer; the drilling rig is then moved to the insulated pad site the following winter.[20] A drilling season can then be increased by 50 to 70 days.[21] But even with this method, drilling seasons are shorter than they were 30 years ago.

If oil is not found in economic quantities, ice pads and roads are allowed to melt, with little effect on plants under the ice. Where pads are maintained over a summer, environmental impact occurs if the tundra around the perimeter of the pad thaws and is blocked from sunlight. In this case, the plants consume stored nutrients completely and die. However, research is being conducted on designs to minimize the perimeter impact. If economic quantities of oil are found, a gravel pad is constructed to support long-term development and construction (and vegetation underneath the gravel dies).

Factors Limiting Use of Ice Technologies

Several factors limit the use of ice technologies. These include (a) the total amount of available fresh water, (b) the distance from sources of fresh water, (c) the topography of the area, and (d) the distance from staging areas.

The supply of fresh water is crucial to using ice technologies as melted saltwater would kill underlying vegetation. The FLEIS noted that the supply of fresh water is limited in the 1002 area

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[20] British Petroleum Exploration Alaska built an insulated pad in March 1996 and, reportedly, eliminated the time needed for demobilizing and mobilizing the rig. See M.J. Stanley and Beez Hazen, "Insulated ice pad technology enables extended season drilling on Alaska's North Slope," *SPE Paper 35686*, Society of Petroleum Engineers (1996).

[21] DOE, *Environmental Benefits of Advanced Oil and Gas Technology*.

and is confined to the surface and the shallow zone of soil located above the impermeable permafrost layer.[22] The Refuge receives an average of six inches of precipitation annually. Most lakes are shallow and therefore freeze solid in winter. A 1989 study found 255 lakes, ponds, and puddles within the 1002 area.[23] Less than 25% were deeper than seven feet; only eight contained enough unfrozen water to build a mile or more of ice road. A number of rivers and streams exist in the 1002 area, and these, too, are usually shallow. Ice chips from lakes and rivers can be used to supplement ice road construction. Each mile of ice road uses an estimated one million gallons of liquid water that road builders typically transport no more than 10 miles, as it may freeze before it is used. Water shortages might be addressed with greater use of chipped ice scraped from lakes, and/or development of new technologies using a desalination plant and a heated elevated pipeline.[24]

Ice road construction also may be limited by the area's topography. Developed areas on the North Slope (e.g., Prudhoe Bay, Kuparuk, and Alpine) are very flat, facilitating ice technology, whereas the 1002 area is hillier, its drainage is better established, and its vegetation is more woody than the wetland grasses that dominate Prudhoe Bay and other developed areas. Foothills and the hilly portions constitute 45% and 22%, respectively, of the ANWR coastal plain. Where topographic relief is high, the State of Alaska has allowed gravel roads in lieu of ice for safety reasons.[25]

Distance from developed areas or potential staging areas can also limit ice technology. As noted, heavy equipment usually would be stored in the nearest possible gravel staging areas, and once ice roads are finished, moved to the drill site. If the distance for ice road construction is great, there will be delay in reaching the drill site, thereby adding to costs. At the production phase, when still more equipment must be moved, the cost of delay could rise further.

As noted above, solutions to these problems exist; if not (as in the case of topographic limits on use of ice roads), gravel construction can be substituted. However, if polar warming continues, use of ice technology may be limited still further. Standards for cross-tundra travel are being changed to accommodate industry needs, while still attempting to balance effects on tundra habitat.

Because it is regarded as a model of modern development, the history of the Alpine field is relevant. Located along the border of the National Petroleum Reserve -Alaska (NPRA), it is considered a model of "roadless" development because of the short (three-mile) road connecting the two initial pads and the lack of connection with the remainder of North Slope development, except in winter via ice road. As noted earlier, however, the recent approval of five additional pads will add about 28 miles of gravel roads to the existing three miles, and create 1,845 acres of disturbed soils. About 150 miles of roads would be built if the field is fully developed.[26]

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[22] FLEIS, p. 13.

[23] Internal FWS study by Steven Lyons, Chief Hydrologist, ANWR, cited in Wayt Gibbs, "The Arctic Oil and Wildlife Refuge", *Scientific American* (May 2001), pp. 62-69. (Hereafter cited as Gibbs, "The Arctic Oil and Wildlife Refuge.")

[24] Gibbs, "The Arctic Oil and Wildlife Refuge."

[25] FLEIS, p. 18-19.

[26] Department of the Interior, Bureau of Land Management, *Alpine Satellite Development Plan Environmental Impact Statement*. See Figure 2.4.6-1, Volume 3, Alternative F, Preferred Alternative, and p. S-8, S-19, S-30 of Summary, at http://www.alpine-satellites-eis.com/, visited on Dec. 13, 2004.

In sum, ice technologies can significantly limit the footprints of development in the exploration phase, especially in flat terrain, with corresponding benefits to tundra vegetation. Experience at Alpine, however, suggests a somewhat more modest mitigation role for ice technologies in development phases after exploration.

Exploration Technology Comparisons

Exploration today is much more efficient, with the use of advanced exploration technology, than it was 20 years ago when the FLEIS was being prepared.

Late 1980s Exploration Technology

In its 1987 FLEIS, the Department of the Interior assumed that additional surface geological work, or field studies, probably would occur in ANWR in the summer months prior to exploratory drilling. Access would be by helicopter, and actual ground time would be only a few hours.

The FLEIS assumed that additional seismic exploration, which would occur in the winter, would take place to obtain more detailed information on subsurface geology,. Use of equipment that generates sound waves by vibrating the earth probably would be the preferred method, and DOI raised the possibility of requests for authorizations to conduct 3-D seismic surveys. It also anticipated a large number of seismic crews, because different companies would want to obtain data in different areas using different acquisition parameters and techniques. Movement of equipment was assumed to take place on ice roads crudely built by packing snow by all terrain vehicles. Ice roads would be constructed of packed snow thick enough to protect the vegetation mat. At that time, the Alaska Department of Natural Resources required 12 inches of frost and 6 inches of snow before vehicles could operate on the tundra.

A single drilling season, from onset of construction through testing and demobilization, was expected to be approximately 170 days. One moderately deep well (less than 10,000 feet) could be drilled in one season. A well deeper than 10,000 feet would require two seasons. If two seasons were required, year-round drilling or a second demobilization and mobilization would be required to continue drilling the following season.

Drill pads were anticipated by DOI to be constructed of ice, excavated material, gravel-foam-timber, or other possible combinations. A pad would be large enough to hold a rig, camp, and facilities for storing equipment and supplies.

Current Exploration Technology

It is likely that field work still would be required in ANWR, as it is the only method that allows the study of the vertical and lateral relationship of the different rock types at the surface or outcrops that one would expect to be potential reservoir targets in the subsurface. While the length of time required in the field may not change, other work could be accelerated by faster interpretation of many data sets and new remote sensing and positioning techniques, compared to those available in the 1980s. Additionally, advances in computer technology help make interpretation of field work more efficient. For example, over the decade, some of the major petroleum companies have been using vast amounts of outcrop-derived rock data from around the world to design and calibrate powerful computer models to predict potential reservoir rock and its properties in the subsurface of an area.

In ANWR, vibrators probably would be used to acquire the seismic data during the winter. This type of seismic data equipment usually is the largest, heaviest piece of equipment used by seismic crews, and requires special methods of transport. The number of seismic crews in the field in a given area may well be about the same as in other regions being explored, as seismic contractors may follow the common practice of conducting seismic programs for multiple companies interested in acquiring data.

3-D seismic data is of interest to the companies interested in exploring ANWR, but 3-D seismic data are not commonly used to explore far from known hydrocarbon fields. Their greatest value is in areas with sufficient data and in the use of the production of a known hydrocarbon accumulation.

Depending on the kind of information needed, the geology expected, and the type of terrain, 2-D seismic surveys can be customized to obtain the necessary seismic data for exploration. Today, 2-D seismic data are of much higher quality than even 15 years ago; and, if programs are laid out correctly, 2-D seismic data are a valuable exploration tool.

Advanced Drilling Technology

Drilling is the only way to measure directly the amount of subsurface petroleum; there is no substitute. It is possible for industry on the North Slope today to drill for thinner and deeper reservoir targets with fewer wells, smaller drill rigs, and with less fluid and solid waste than it was 20 years ago.

An Introduction to Drilling: The Processes and Terms

Drilling a well requires the use of a *drilling rig*, which controls rotating pipe or *drill pipe*, on which a cutting tool, or *drill bit*, is attached. The drill bit needs to be lubricated by drilling fluids, usually a natural or synthetic fluid called *mud*. Equipment can be placed on the bit to direct the location and movement of the bit. As the pipe rotates and cuts through the rock below the surface, it produces rock chips or *cuttings*, which flow to the surface in the mud and placed in shallow, plastic-lined holes on the drill pad, called *reserve pits*, or *reinjected* into the subsurface. *Evaluation tools* are used measure the rock characteristics. To preserve the well hole, or *borehole*, being drilled, mud is used to hold back the subsurface rocks during drilling, and *casing*, or pipe, is placed in the hole to protect the overlying rocks and the reservoir rocks. Casing also controls the flow of drilling fluid and oil, gas, and water from the reservoir after a part of the hole is drilled. The borehole also is the conduit for petroleum and water from the reservoir to the surface. If the flow of fluid up the borehole is uncontrolled, a *blowout* (in the least extreme case, a *kick*) occurs. Prevention techniques are used first to *kill the well*, or stop the fluid flow. As a last resort, equipment, a *blow out preventer stack, BOP*, or *blind rams* placed at or near the surface over the top of the well-bore are used to stop the flow of fluids. The direction of the borehole is the *well path*, and the equipment at the beginning of the borehole at the surface is the *wellhead*. If the well encounters hydrocarbons, the casing and formation are *perforated* to allow hydrocarbons to flow into the borehole to the surface. Wells drilled from a common borehole are called *sidetracks*

Directional Drilling

Directional drilling—accurately drilling through rock layers in the subsurface at angles other than vertical while guiding a well-path to a predefined target—involves integrating a complex set of technologies to solve technical, control, and safety problems. These problems can be related to unexpected subsurface pressure regimes and fluid types. As these problems have been and are being solved, directional drilling has gained widespread acceptance. The advantages of directional drilling are:

- multiple wells can be drilled from a single location, allowing easier connections to production facilities and less surface disruption;
- targets below environmentally sensitive areas can be reached from a different location up to five to seven miles away;
- more of the target reservoir formation can be accessed from a borehole, reducing the number of wells; and
- in case of a *kick* (see box), relief wells can be drilled at an angle to kill the well.

Technology now allows wells to deviate from the vertical from a few degrees to horizontal, depending on the subsurface geology and the environmental constraints. Types of directional wells are extended reach, horizontal, and designer or complex wells. (See **Figure 1**).

Extended Reach Drilling (ERD) and Horizontal Well Drilling

ERD wells evolved rapidly in the 1990s, and generally are used to reach targets in environmentally sensitive areas from fewer surface locations. ERDs have a horizontal displacement of two to five times the vertical depth. Wellheads can also be located closer to each other, allowing for easy hookup to production facilities. In the late 1960s, ERD could reach out a little more than a mile. Now, ERD wells can routinely go out about four miles, and five- to-seven-mile long ERD wells have been successfully completed in the North Sea and China.[27] The seven-mile distance between the discovery and the confirmation well at Prudhoe Bay could have been drilled by ERD from one location.

Horizontal wells are ERD wells drilled vertically to the desired depth and then turned 90 degrees to continue horizontally through rock formations for up to five miles. Drilling ERD and horizontal wells require specialized equipment such as motors placed near the bit and equipment to stabilize the well-path. Because of the difficulties of using standard evaluation tools in these wells, evaluation tools have been developed that measure the rock characteristics at the drill bit while drilling.

Designer Wells

These are drilled with high precision at sharp angles, at times less than 90° and even to a near circle. They are designed to reach small targets, several small oil accumulations at one time, or to go around geological barriers. Complex well drilling has been made practical by the use of 3-D seismic data that allow reservoir engineers to plot subsurface features to within 10 feet, and made possible by new technologies that allow tight turns with steel pipe.

The drilling of a well itself (see box on the previous page) has not been the limiting operation in horizontal and ERD wells. The limitations are the physical operations of working with long, non-vertical strings of steel pipe. As discussed in the next section, drill bit technology and new drilling fluid systems have been developed to help alleviate the problems of high performance drilling.

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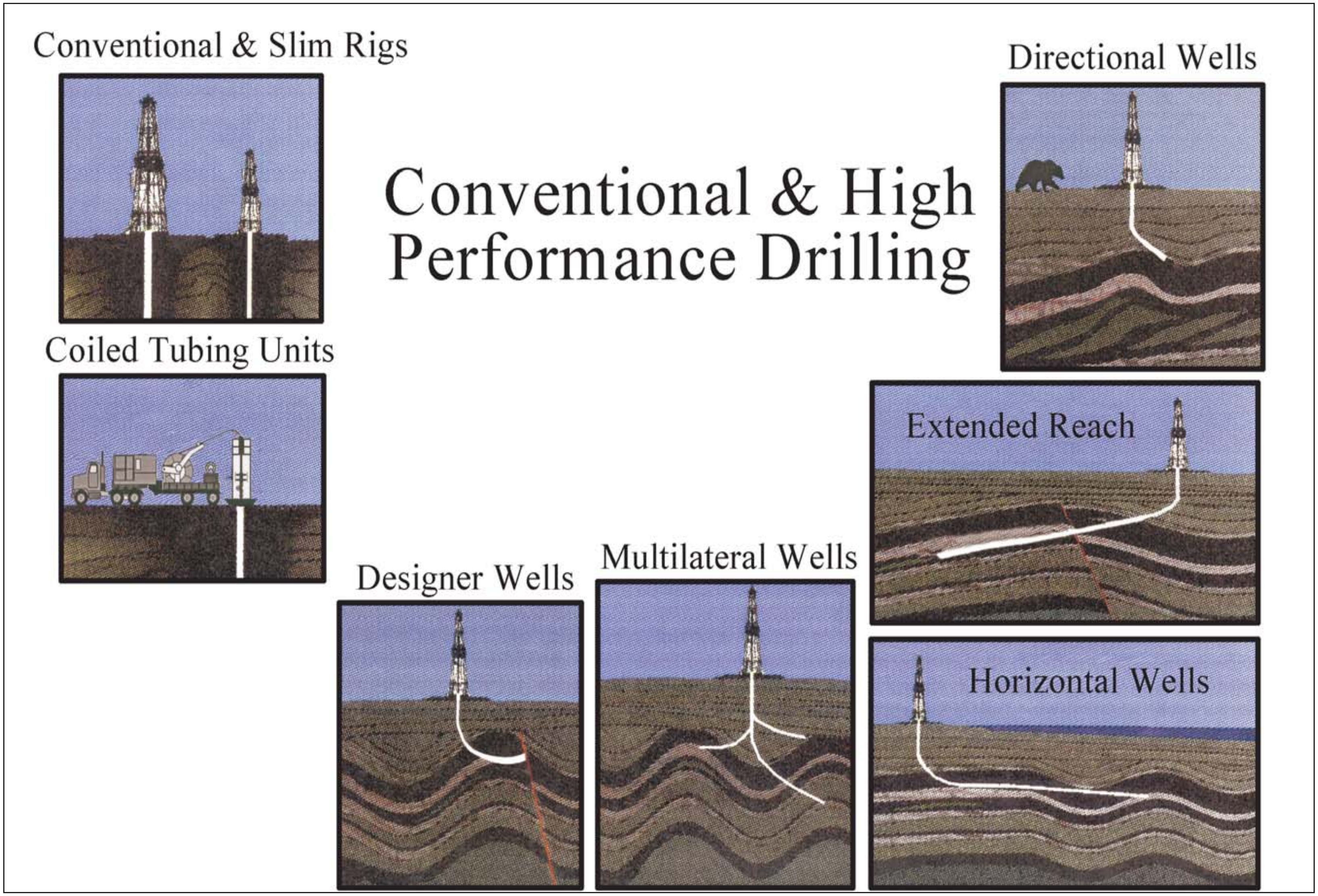
[27] DOE, *Environmental Benefits of Advanced Oil and Gas Technology*; C.J. Mason and A. Judzis, "Extended-reach drilling – What is the limit?," *SPE Paper 48943*, Society of Petroleum Engineers (1998).

Figure 1. Conventional and High Performance Wells Used in Drilling Today



Drill Bit Technology and Drilling Fluid Systems

Advances in drill bit technology and drilling fluids have improved drilling performance significantly by allowing wells to be drilled more quickly.

Drill Bits

Greater efficiency during the drilling phase allows for shorter times in an area. Extending the drill bit life at the bottom of the hole saves time. Bits such as the polycrystalline diamond compact (PDC) bit provide for faster drilling and can be used much longer. The PDC bit was introduced by General Electric in 1973. The bits use cutters made of a thick layer of tungsten carbide impregnated with bonded diamond particles. Diamond is 10 times harder than steel and is the most wear-resistant material in existence.

Drilling Fluids

Drilling fluids, or muds, are essential to carry drill cuttings of the rock to the surface, for maintaining pressure balance and stability in the open hole in the subsurface, for lubricating and clearing the down-hole cutting equipment, and for preventing the influx of other fluids from the rock. Millions of research and investment dollars have been spent over the last decade to improve the performance of these drilling fluids, and to avoid problems caused by inappropriate fluids.

Three types of fluids are used in drilling: water-based mud (WBM), oil-based mud (OBM), and synthetic-based mud (SBM). Because OBM is hard to handle and to dispose, SBM is being developed to act like OBM without the environmental problems. In developing of SBMs, operators are using other organic substances to replace oil. SBMs combine the performance of OBMs, which cannot be discharged on-site, with the easier, safer disposal of water-based muds.

Drilling Technology Comparisons

Drilling Paradigm in the Late 1980s

DOI described drilling as a large-scale operation using heavy equipment confined to a localized area for an exploration well, and spreading over multiple sites to delineate a newly discovered field. Drilling typically was expected to be conducted during the winter for the exploration and delineation wells.

A typical drill pad including the reserve pit covered five to ten acres, which included facilities to house 100-135 workers during construction and drilling of the well. Reserve pits were excavated on the pad. The reserve pit generally covered 0.5 to 2.0 acres and was 10 to 20 feet deep. A flare pit or a vent system for excess gas was also included on the drill pad.

Current Technology

Conventional vertical wells most likely would be used for drilling exploratory wells in ANWR. If a potentially commercial hydrocarbon accumulation were found, high performance drilling techniques likely would be used to reduce the number and size of drill sites and allow drilling fewer delineation wells. Probably all wells would be drilled in the winter. Prudhoe Bay had 42 drill sites constructed in 1971-1977 to develop the estimated 9.6 billion barrels of oil. If Prudhoe Bay were developed with horizontal drilling only, 11 sites would be needed to develop an estimated 14 billion barrels of oil.[28]

Temporary reserve pits, if needed for storage of well cuttings, would be surrounded by walls of ice on the ice pad. According to ARCO Alaska, now Phillips Alaska, cuttings would be transported to sites where they could be cleaned and could be used for construction material. Cuttings might also be reinjected into special wells for solid and fluid drilling wastes, if permitted.

Production Methods: Reduction in Physical Presence

Production facilities are necessary to extract hydrocarbons through the life of a field. They consist of airstrips, power plants, production pads, access roads, flowlines, and crew offices and living quarters. New developments in production field facility construction and maintenance and in production drilling techniques have reduced the footprint of oil and gas operations and should reduce environmental impacts. A by-product of both drilling and production advances has been the reduction in oilfield solid and fluid waste volumes.

Compact Facilities or Central Processing Facilities (CPF)

Compact production facilities are transportable unmanned production facilities that may be used to exploit remote accumulations in environmentally sensitive areas such as the Arctic. Four elements common to these facilities are design integration, equipment elimination, multi-use systems, and automation. The use of 3-D animation graphics, borrowed from the automobile and airplane manufacturing industries, allows for the design of compact facilities. 3-D graphics combine engineering design and the different ways one would be able to construct the production modules. The ability to “see” on a computer screen how the modules will function in the Arctic and to instantly “see” the effects of suggested changes results in more efficient design and construction of the facilities.

Zero Discharge of Solid and Fluid Wastes

The major drilling wastes are drilling mud, water produced along with the oil, and drill cuttings. Drilling mud is pumped down a borehole into rock layers in the subsurface containing enough pore space to accept additional fluids without inducing cracks in the rock. The borehole must be adequately protected by casing strong enough to contain the fluid in the rock that would flow into the borehole as a result of the higher reservoir pressures. Currently, all liquid and all solid drilling and associated wastes generated at the recently developed Alpine Field are disposed of by injecting them into the subsurface. At Prudhoe Bay, all drilling wastes are treated and reinjected into the subsurface. Associated wastes such as office paper and food waste are burned on site and the ash is transported elsewhere for disposal.

[28] DOE, *Environmental Benefits of Advanced Oil and Gas Technology*.

Water almost always is produced together with oil, and the amount of water increases as oil production from a given field decreases. Usually water and oil are pumped to the surface for separation, but systems below the surface can now separate oil and water. New down-hole separation technologies may be able to reduce the amount of produced water by as much as 97% in some wells.[29] Dual pump systems at and above the reservoir level pump the oil and reinject the water into the subsurface.

British Petroleum Exploration Alaska built a prototype grinding and injection facility that recycled cuttings into construction gravel in 1990. The facility also ground associated operational wastes for subsurface re-injection. By 1994, refined grind-and-inject technology enabled Prudhoe Bay operators to achieve zero surface discharge of drilling wastes, eliminating the need for reserve pits. Additionally, in 1988, ARCO conducted a pilot project indicating that cleaned and processed drill cuttings could be used safely as road construction material. The composition of the cuttings is said to be very close in to that of native gravel and surface soils.

Improved Production Drilling

Over the past 100 years, industry has employed only two basic drilling rigs, cable and rotary. Cable drilling is pounding a hole in the earth with a heavy rod to depths of up to 7,000 feet. Rotary drilling with the use of surface-rotated, jointed drill pipe, much like a household electric drill, is now used to drill into the subsurface to much greater depths. Today, production drilling technologies allow for smaller drilling units than conventional ones, contributing to reduced equipment size.

Slim Hole Drilling

Slim hole drilling has been used in one form or another by the oil and gas industry since 1960 as a way of reducing costs and improving exploration and drilling results.[30] Slim holes are 3-4.25 inches in diameter, while conventional holes are 8-10 inches at the bottom of the well. A slim hole drill rig uses 97% less drilling fluid, generates one-third less cuttings volume, and has a 25-man drill crew instead of a conventional rig crew of 40.[31] Transport of equipment and rig can be by helicopter for easier access to remote areas.

Slim hole drilling also can be used in exploratory wells to gather cores from the subsurface, and slim holes are used in improved production drilling techniques discussed below. However, the shortcomings of slim hole drilling are poor methods to keep fluids from escaping the borehole and the need for non-standard bits and well evaluation tools. Also, if a drill pad were to benefit from slim hole drilling, all wells on that site may need to be slim hole wells.

Coiled Tubing Drilling (CTD)

Traditional rotary drilling rigs are as tall as 200 feet and include 30-foot portions of drill pipe that must be connected to increase the length of the pipe as the well goes to greater depths. In CTD

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[29] DOE, *Environmental Benefits of Advanced Oil and Gas Technology*.

[30] Petroleum Technology Transfer Council, *Developments in Well Stimulation and Slim Hole Technology*, based on a workshop sponsored by PTTC's Central Gulf Region on December 5, 2000, in Lafayette, Louisiana.

[31] DOE, *Environmental Benefits of Advanced Oil and Gas Technology*.

units, a large drum containing a reel of seamless steel pipe that is quite flexible is used. CTD units drill rock with the use of a motor on the bit to drive the coiled steel through the formation. CTD drilling was used first on the North Slope in 1991.

Some of the advantages of CTD are:

- very little pipe handling and no drill pipe connections;
- better control of fluids in the borehole, allowing for the use of lighter, less toxic muds;
- noise at 45 decibels instead of 55 decibels;
- smaller sites (less than half) and less surface disturbance because it is easier to handle the equipment during the preparation for drilling;
- less heavy equipment, lower fuel consumption and emissions; and
- no personnel necessary at the wellhead.

Disadvantages of CTD are:

- small diameter drill pipe is used and limits the utility for some drilling objectives, such as exploration wells;
- the drill pipe cannot be rotated from the surface, mandating more-advanced drilling practices and equipment; and
- the reel of coiled pipe is heavy and often difficult to transport and lift.

Multilateral Drilling

Multilateral wells were first used in production drilling on the North Slope in 1999. From a central borehole, additional boreholes are drilled to different locations—branching from a common borehole. Because the secondary boreholes share a central borehole, they can share the same surface facility.

Through-Tubing Rotary Drilling Wells

The most recent, and very innovative, technology developed on the North Slope in years, is through-tubing rotary drilled (TTRD) wells. With TTRD, a new well is drilled through the production tubing of an older well as a multilateral well. Because the old tubing doesn't have to be pulled out of the ground by a drilling rig, a rig even smaller than a CTD unit can be used for drilling. One of the benefits of TTRD equipment is that the unit can be transported over ice bridges with stringent weight restrictions. These benefits allow access to areas not open to conventional rigs and decrease the number of surface drilling sites. However, the technology is useful only in areas where production wells have been completed in the past.

Comparison of Production Technology

Production in the Late 1980s

The 1987 FLEIS evaluation assumed the production facilities would be producing from a hydrocarbon accumulation of 35,000 acres in the subsurface. This accumulation was estimated to require 220 production wells and 90 injection wells. Expected well spacing was 120 feet, requiring seven 20- to100-acre drill pads constructed of gravel and containing 40 to 50 wells on each drill site. The production facilities posited would have included operations offices, fuel and water storage, electrical power-generation units, solid and fluid waste and water-treatment facilities.

The impact of petroleum operations on the surface was estimated in 1987 to extend only to the size of the accumulation (i.e., 35,000 acres). DOI projected that the subsurface size and shape of the productive field would define the areal extent of the surface disturbance from the central production facilities. Directional drilling from one pad site was posed as an option, and the directional wells were assumed to have been drilled at angles up to 60°.

Peak production was assumed to be attainable in two to five years and to remain at this level for three to eight years, with the productive life of the field projected at 20-30 years. While difficult to determine in the Arctic, about a 10 year time lapse was expected from lease acquisition to initial production under optimal conditions.

The drill cuttings would have to be placed in a reserve pit (0.5 - 2.0 acres, 10 - 20 feet deep) on the drill pad. Drilling muds would be reinjected into previous drilled wells, and hazardous solids and wastes removed and held in a government-approved site.

Current Production Technology

Today's production facilities are more compact, with multi-faceted, multi-functional modules and production techniques. Computer graphics now allow operators to plan a site and to make changes before construction begins at the site.

The Alpine field is a 40,000-acre accumulation with operations including two production drilling sites connected by a road/airstrip; these structures cover 97 acres. Alpine field operations occupy only 0.2% the area of the hydrocarbon accumulation, whereas Prudhoe Bay facilities occupy twice the area of the accumulation. Alpine's footprint is reduced by drilling all wells horizontally and from compact facilities.

Permanent drill sites can be much smaller today, partly because drill solids and fluids are reinjected and not put in reserve pits. Multilateral wells and coiled tubing wells drilled as slim hole wells require less mud and produce less waste. TTRD units can be used to access hard-to-reach areas over light-load bridges and in seasons with barely frozen tundra. Gas may not be flared, except for safety reasons, but can be used in projects during production, and may be flared for safety reasons only.

However, today in Alaska, drill sites still would be constructed of gravel or recycled cuttings from the exploration wells. Well cuttings may be treated and used as construction material in place of gravel. Produced water today is greatly reduced by improved production techniques. By 2001, more than 95% of the associated operational waste were being recycled at Prudhoe, and operators at the Alpine field had a project goal of zero discharge of all wastes.[32]

Observations

Gains from North Slope Experience

Thirty years of development experience on the North Slope have led to considerable advances in exploration, drilling, and production operations, and a reduction in the size of the footprint of petroleum operations in Arctic environments. These advances, many of which are used at the Alpine field, would be available for use in the 1002 area of ANWR, should it be opened by Congress.

Exploration success rates have improved dramatically, which probably would mean fewer exploration wells. The use of 3-D seismic technology during the exploration for hydrocarbon fields and the production stages of fields on the North Slope enables geologists and geophysicists to be more proficient in interpreting seismic data and in identifying the type of hydrocarbon. And the use of computer-aided models results in fewer and better-placed wells.

Partly to protect the North Slope's tundra, exploration operations are conducted exclusively in the winter with extensive use of ice roads and all-terrain vehicles.[33] Advances in seismic acquisition and processing techniques allow for permafrost exploration using vibrating instead of explosive techniques.

Reductions in the size of production facilities have decreased the footprint of more recent North Slope operations. The minimum spacing between onshore wells has been reduced by about 80%, from 160 feet to 35 feet. An average production drill site has shrunk about 85%, from 65 acres to fewer than 9 acres, and fewer dril sites are needed with new high performance drilling techniques and production drilling technology; and reserve pits have been eliminated or used on insulated ice pads only temporarily.

North Slope operators are using advanced technology to manage drilling wastes more effectively. Cleaned well cuttings can be used for construction material in roads and other gravel structures. Grind-and-inject technology can enable 100% of all drilling solid and fluid wastes to be injected into the subsurface, which eliminates the need for reserve pits. Additionally, fewer wells drilled means that less solid and fluid waste is generated.

Conclusions

There are supportable grounds for proponents of opening ANWR to energy development to assert that the advanced technologies for oil and gas development in the Arctic might significantly

[32] Personal communication with Dawn Patience, Phillips Alaska, at Anchorage, May 2001.

[33] However, warming trends in the high Arctic have shortened the exploration season over the last 30 years. The shorter season is now addressed by having two starting dates and two stopping dates—a shorter season for heavy equipment, and a longer season for lighter vehicles. In addition, studies (conducted jointly by federal and state agencies, as well as academic experts) are underway to modify current standards for cross-tundra travel; these may result in a further lengthening of the exploration season.

mitigate the effects on the environment of oil and gas operations. But opponents assert that, notwithstanding technological improvements, facilities of any size would be an industrial site and an intrusion on the ecosystem that would use the area's natural resources, interfere with wildlife, risk spills of hazardous materials, and result in a permanent loss of wilderness. In the final analysis, the issue of whether to open ANWR to energy development remains a policy decision.

Exploration Within ANWR

Section 1002 (a) of, the Alaska National Interest Lands Conservation Act of 1980 (ANILCA) directed the Department of the Interior (DOI) to assess the plant and animal resources and the hydrocarbon potential in 1.5 million acres of the coastal plain portion of ANWR, referred to as the 1002 area. This assessment included surface geological and geophysical work, but no exploration drilling.[34]

1983-1985 Oil and Gas Exploration Programs

Exploration crews from 15 companies visited the 1002 area during the summers of 1983-1985. Access by helicopter was allowed, but no ground vehicles were permitted. The work was monitored by the U.S. Fish and Wildlife Service (FWS), which observed no adverse effects on fish and wildlife from geological field operations such as collection of rock samples and mapping. The goal of the field work was to collect rock or outcrop data to better understand the rocks that could be potential reservoir and source rocks. However, the data to determine rock type and distribution in the area were from outcrops covering only 4.0% of the 1002 area.

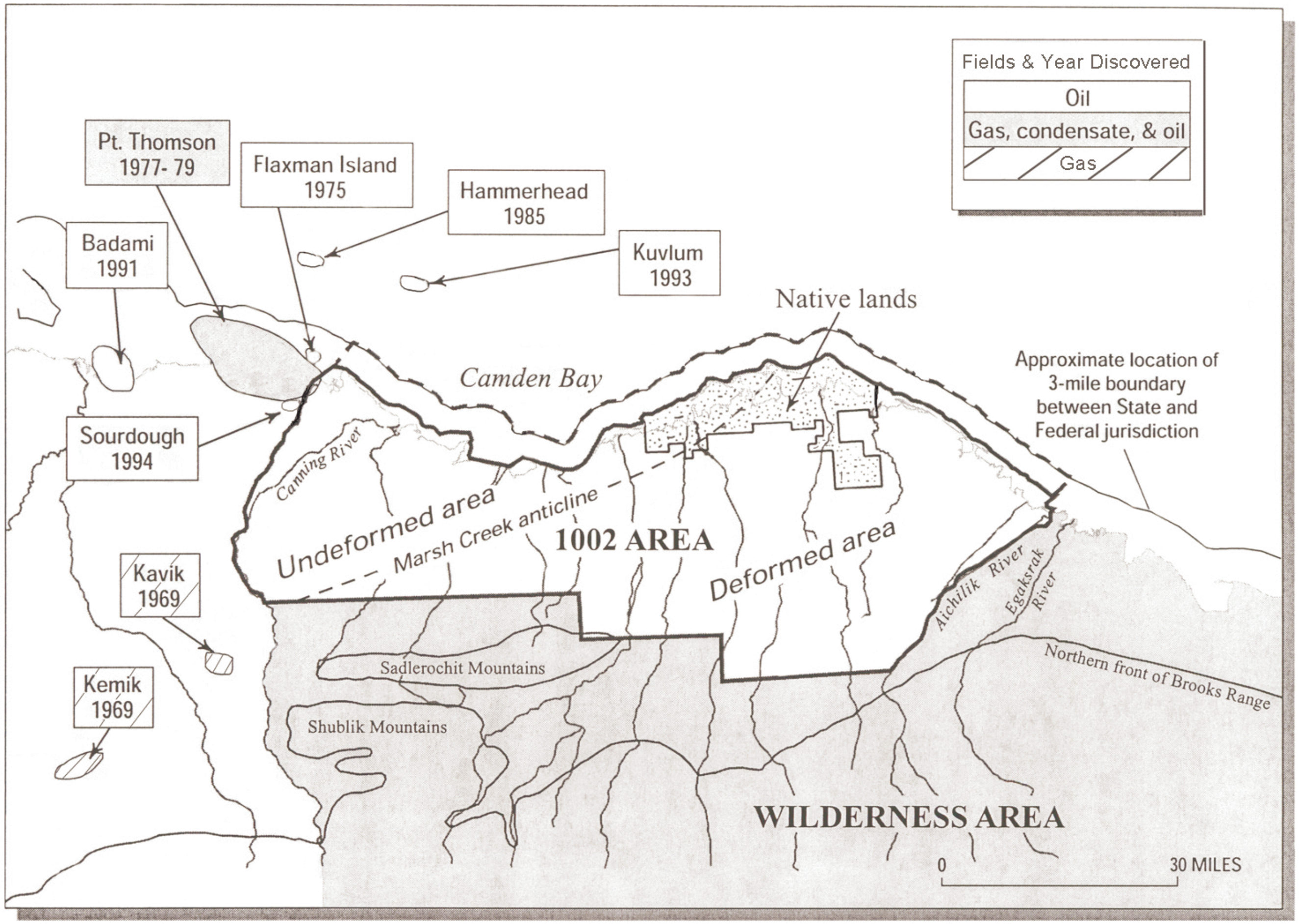
Seismic operations were permitted during the winters of 1983-1984 and 1984-1985, when most wildlife species were absent or present in smaller numbers. As seismic surveys are the only exploration technique involving mechanized surface transportation, it posed the greatest possibility of adverse environmental effects. To avoid significant adverse impacts, access was limited to one seismic contractor and activities in acutely environmentally sensitive areas were restricted. The total distance in straight and parallel tracks called line-miles in the 2-D seismic survey was restricted to approximately 1,300 line-miles, which the FWS believed was sufficient to identify potential areas for the purpose of the FLEIS report. Full-time FWS monitors accompanied each seismic crew. The FWS effectively limited short-term adverse environmental effects, but followup studies were planned to determine the long-term impacts. It is unclear if such studies were carried out or published.

Petroleum Geology

ANWR's 1002 area is between two known petroleum provinces, the U.S. North Slope to the west and the Canadian Beaufort Sea and Mackenzie Delta province to the east. Interpretation of the regional geological data collected during the summers of 1983-1985 and more recent nearby well data by the Bureau of Land Management (BLM) in 1991 and the U.S. Geological Survey in 1998 indicate that the rocks of both provinces may extend into the 1002 area (**Figure 2**).

[34] For additional information, see U.S. Department of the Interior, *Arctic National Wildlife Refuge, Alaska, Coastal Plain Resource Assessment*.

Figure 2. Map of the 1002 area of the Arctic National Wildlife Refuge.



Source: Arctic National Wildlife Refuge, 1002 Area, Petroleum Assessment, 1998, USGS Fact Sheet FS-040-98, May, 1998.

The dashed line labeled Marsh Creek anticline marks the approximate boundary between the undeformed and the deformed areas established by the USGS in 1998. Fields and discovery dates are shown surrounding the 1002 area.

The approximate 1,300 line-miles of seismic data were reprocessed and reinterpreted between 1987 and 1998. These data, in addition to the geological data, were used in the 1991 petroleum assessments of ANWR by BLM and by the USGS

in 1998.[35] In its 1998 study, the USGS divided the 1002 area into two areas based on the type of geological structures or potential hydrocarbon traps. The first is a structurally simple area called the undeformed area, and the second a more structurally complex, more stressed area called the deformed area. The geological sequence in the northwestern portion of the 1002 area, the undeformed area, is similar to the sequence encountered within the North Slope, which includes the Prudhoe Bay, Kuparuk River, and Alpine fields.

The southeastern deformed region of the 1002 area is more like the Canadian Beaufort and Mackenzie Delta, which include more than 36 hydrocarbon fields totaling 740 million barrels of oil and 10 trillion cubic feet of gas. Because of the geologic complexity, selection, acquisition, and interpretation of data in the deformed area is difficult compared with acquiring and interpreting data from the undeformed area. If ANWR were opened, drilling and production techniques in the deformed area would be different than in the undeformed area because of this complexity.

The determination of the existence of a source rock that can generate petroleum is important before active exploration begins in a new area. The potential for rocks to generate hydrocarbons is determined by the organic geochemistry of the rocks on the surface or in the subsurface. The geochemistry of the outcrops, analyzed from the outcrop samples taken in 1983-1985, indicate that five rock sequences sampled in the 1002 area have the potential to generate oil and gas. Gas can be generated from the same rocks that produce oil, but the rocks need to have been buried to greater depths and higher temperatures. Gas can also be generated from rocks with a different organic content than the oil-generating rocks. Only one of the five rock sequences in the 1002 area is more prone to producing oil than gas. The other four identified rock sequences are more likely to produce gas.[36]

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