Petroleum Potential of the Arctic: Challenges and Solutions

Although Arctic oil and gas have been E&P targets for decades, the petroleum potential of this region is far from being fully realized. The Arctic environment is fragile, climate conditions are harsh and the operational season is short. Success in this remote area will depend on appropriate selection of existing technologies and development of novel, more efficient ones.

The Arctic region has drawn attention since ancient times—attention well beyond mere curiosity about the great unknown. Fur, fin and feather from the Arctic coasts were the earliest attractions, enticing people from other regions to these frigid waters and icy expanses. Legendary treasures in distant Asian lands and the long, difficult and often dangerous southern sea route to obtain them impelled European travelers to dream about alternative paths and turn their eyes to the north.

Starting in the 16th century, explorers sought the Northwest Passage to the Pacific Ocean along the north coast of North America, as well as a Northern Sea Route along the north coast of Eurasia, often guided by fantastic notions of the geography of the region (next page). In the late 19th century, exploration of these northern territories reached the highest latitude: the North Pole. These far-reaching adventures and discoveries further enabled active scientific and commercial enterprises. The age of oil was coming, and explorationists extended their interest to even more-remote areas in a quest for what is now considered one of the greatest treasures of the Arctic—hydrocarbon reserves.

First Discoveries

The Arctic is variously defined in the E&P industry. Its geographic definition covers territories north of the Arctic Circle, at latitudes greater than 66°33’44” N. Other definitions include any regions with Arctic-like conditions, such as a particularly cold climate, or with permafrost, floating ice and icebergs. These extended definitions encompass vast areas—such as West Siberia and Sakhalin, Russia; northern Canada; and Alaska, USA—with rich hydrocarbon exploration and production histories.

The indigenous Inuit people of Alaska had long known about oil seeps on the Arctic coastal plain. Russia owned the Alaskan territory until 1867, and Russian settlers were the first westerners to report oil shows on the Alaska Peninsula.¹ The late 19th to early 20th century saw the first successful exploration and production efforts in Alaska, but the first major commercial oil and gas fields there were discovered only as recently as the late 1950s. However, all of these successes were achieved in southern Alaska. The discovery of the first true Arctic commercial hydrocarbon field in Alaska occurred a decade later.

³. Company names in this article are given as they existed at the time. British Petroleum became BP, ARCO was acquired by BP, and Standard Oil Company of New Jersey became Exxon, now part of ExxonMobil.
On March 12, 1968, ARCO and Standard Oil Company of New Jersey drilled a well that tapped North America’s largest oil field and the 18th-largest in the world—the Prudhoe Bay field on Alaska’s North Slope. British Petroleum drilled a confirmation well in 1969. An early estimate for the field was 1.5 billion m$^3$ [9.6 billion bbl] of recoverable oil. By today’s estimates, from the 4.0 billion m$^3$ [25 billion bbl] of original oil in place (OOIP), 2.1 billion m$^3$ [13 billion bbl] of oil can be recovered with existing technologies. The field also contains an estimated 1.3 trillion m$^3$ [46 Tcf] of natural gas in place in an overlying gas cap and in solution with the oil, of which about 786 billion m$^3$ [26 Tcf] are classified as recoverable.

Moving Prudhoe Bay oil to market required the operators to solve a variety of problems, from climatic and technological to environmental and legal. Completion of the Trans Alaska Pipeline from Prudhoe Bay to Valdez, Alaska, constructed
between 1974 and 1977, allowed oil production in the field to begin (above).

In the Canadian Arctic, east of Alaska, indigenous people had also been aware of oil seeps for centuries and had even used hydrocarbon pitch to seal seams on canoes. Oil seeping along the banks of the Mackenzie River was first reported by westerners in 1789. Some subarctic fields were discovered in the 1920s. But the first purely Arctic hydrocarbon field in Canada, discovered in 1969 by Panarctic Oils, was the Drake Point gas field on Melville Island in the Canadian Arctic Archipelago. The current estimated gas reserves of the field are 153 billion m³ [5.4 Tcf]. In 1974, Panarctic Oils discovered the first Canadian Arctic oil field—the Bent Horn field on Cameron Island. Although relatively small, this is the only Canadian Arctic oil field that has been commercially produced. The field was abandoned in 1997, but produced 453,16 thousand m³ [2.85 million bbl] of crude oil from 1985 to 1996. Today, natural gas is considered the most promising hydrocarbon reserve in the Canadian Arctic, and the highest gas potential is expected from the Mackenzie Delta–Beaufort Sea basin and basins of the Arctic Archipelago.

The petroleum potential of Greenland—east of Canada and a self-governing territory of Denmark—has not been extensively explored (below left). Much of Greenland’s territory lies north of the Arctic Circle. About 80% of the island is covered by the Greenland ice sheet—an ice body generally more than 2,000 m [6,600 ft] thick—which complicates exploration activities considerably. It was not until the early 1970s, the time of a dramatic rise in oil prices, that the first large seismic surveys were carried out offshore West Greenland, mostly within the Arctic Circle. This exploration period lasted until 1978, with no discoveries. Five exploratory wells were also drilled in 1976 and 1977—all dry holes. Exploration resumed in the early 1990s, with the first oil seeps in Greenland’s waters found in 1992. The Marraat-1 well, drilled in 1993, demonstrated substantial oil leakage from cores. Since then, seismic and airborne geophysical surveys have been commissioned, and a few more offshore and onshore wells have been drilled. Some structures with hydrocarbon potential have been identified, and onshore oil seeps and offshore slicks have been observed. However, to date, no oil or gas fields of any commercial significance have been discovered in Greenland.

Iceland, Greenland’s neighbor, may also have some Arctic petroleum potential. In 1981, Iceland and Norway agreed on a partition of the Continental Shelf in the area between Iceland and Jan Mayen Island and on a joint project to map the subsea resources of the Jan Mayen Ridge. A 1985 seismic survey and subsequent surveys identified two areas of the Icelandic shelf that are thought to have potential for commercial accumulation of oil and gas. In the Dreki area, east and northeast of Iceland, the thick continental crust potentially includes Jurassic and Cretaceous source rocks and is geologically similar to hydrocarbon basins in Norway and

Trans Alaska Pipeline. This pipeline system extends for 800 mi [1,300 km] from the north coast of Alaska to the south coast. The 4-ft [1.2-m] diameter pipeline is managed by the Alyeska Pipeline Service Company, which is owned by BP Pipelines (Alaska) Inc., ConocoPhillips Transportation Alaska, Inc., ExxonMobil Pipeline Company, Koch Alaska Pipeline Company, LLC and Unocal Pipeline Company. (Photograph copyright of BP plc.)
Greenland. Gammur, on the northern insular shelf of Iceland, is a relatively young sedimentary basin of about 9 million years, from which gas escapes have been reported.¹³ In 2009, Iceland held the first licensing round for exploration and production licenses in the Dreki area, and the second round opens in 2011. However, existing surveys estimate the probability of hydrocarbon discovery as low.

Norway, conversely, is one of the world’s largest petroleum producers and exporters. All of Norway’s petroleum reserves are located on the Norwegian Continental Shelf in three marine regions: the North, Norwegian and Barents seas, but only the Barents Sea has Arctic petroleum production. Seismic surveying began in the region in the early 1970s, followed by exploratory drilling in 1980, when the Norwegian parliament permitted drilling north of the 62nd parallel. In 1984, Statoil discovered the Askeladd, Albatross and Snøhvit fields, which are collectively called the Snøhvit development.¹² The Snøhvit development is now the world’s northernmost offshore gas field, and its estimated recoverable reserves are 194 billion m³ [6.8 Tcf] of natural gas, 18 million m³ [113 million bbl] of condensate and 5.1 million metric tons [53 million bbl] of natural gas liquids.¹⁴

Elsewhere in the Barents Sea, exploration activities continue, and this region is considered a promising area for hydrocarbon production not only by Norway but also by Russia (above right). The Kara Sea, the Barents Sea and its southeastern part, the Pechora Sea, are now the most explored areas of the Russian Arctic. The first offshore Russian Arctic field—the Murmanskoe gas field—was discovered in 1983 in the Barents Sea.¹⁵ The recoverable gas reserves of this field are estimated at 122 billion m³ [4.3 Tcf].¹⁶ In 1986, the first Russian Arctic offshore oil was discovered at the Severo-Gulyaevskoe oil and gas condensate field with estimated recoverable oil reserves of 11.4 million metric tons [84 million bbl].¹⁷ Fifteen hydrocarbon fields have been discovered to date in the Kara, Barents and Pechora seas, including three supergiant fields—Shotokman, Rusanovskoe and Leningradskoe—

8. The most recent attempt was made by Cairn Energy. By September 30, 2010, the end of the drilling season in Greenland, Cairn Energy had drilled two of the four planned wells in the West Disko area, Baffin Bay, West Greenland. The company found traces of hydrocarbons but no commercial discoveries.
9. All of the main island of Iceland is south of the Arctic Circle; however, Grimsey, a small island north of the country’s main island, lies on the Arctic Circle.
10. Jan Mayen, a volcanic island in the Arctic Ocean between Greenland and northern Norway, is a part of Norway.
13. Traditionally, in countries using the metric system, condensate is measured in metric tons (mass unit), whereas in the US it is measured in barrels (volume unit). Conversion of one unit to the other requires knowledge of density. The US Energy Information Administration provides an approximate conversion factor of 10.40 bbl/metric ton that is used here. http://www.eia.doe.gov/emeu/aia/tables1.html (accessed August 19, 2010).

[^Arctic fields (red dots) and other locations mentioned in this article.}
but none are producing yet. The Prirazlomnoe oil field in the Pechora Sea is expected to begin production in 2011. Its estimated recoverable reserves are 58.6 million metric tons [430 million bbl].17 Offshore regions farther east—the Laptev, East Siberian and Chukchi seas—are less explored but promising.

Almost all of the developed Russian oil and gas fields are located onshore, and many important ones, including giant fields, are north of the Arctic Circle. The Yamburg oil and gas condensate field, for example, is the world’s third-largest gas field with estimated reserves of 4 trillion m³ [141 Tcf] (above).18 Explorationists first investigated this remote area in 1943, during World War II, when the country was in acute need of hydrocarbons. These endeavors were suspended, and it was not until 1959 that exploration activities resumed. Discovered in 1962 near the Taz Estuary in the northern area of West Siberia, the Tazovskoe gas field was the first discovery in the Russian Arctic. The field has estimated gas reserves of about 200 billion m³ [7.06 Tcf].19 The Zapolyarnoe oil, gas and condensate field, discovered in 1965, was the first Russian Arctic oil field. This is also the world’s sixth-largest gas field with 2.7 trillion m³ [95 Tcf] of recoverable gas.20 However, the time from discovery to production may sometimes take decades in this challenging region. Although it was discovered 45 years ago, this field produced its first gas only in 2001.

Arctic Petroleum Reserves Estimates
Since the time of these early discoveries throughout the Arctic, explorationists have wondered about the size of Arctic resources and how they are distributed among different basins and countries. Estimates of Arctic reserves depend on the parameter values and methods used, and may change as new data become available or another evaluation technique is applied. In 2000, the US Geological Survey (USGS) estimated that the Arctic, with 6% of the world’s area, holds 25% of the world’s undiscovered oil and gas reserves. The USGS obtained this figure after assessing seven of the most studied oil and gas basins. Since then, with improved data and a growing level of interest in Arctic oil and gas, the estimate has been updated.

In May 2008, the USGS completed a new assessment, the Circum-Arctic Resource Appraisal (CARA), which was performed using a probabilistic methodology of geologic analysis and analog modeling.21 The total undiscovered conventional hydrocarbon resources of the Arctic were estimated to be approximately 14.3 billion m³ [90 billion bbl] of oil, 47.3 trillion m³ [1,669 Tcf] of natural gas and 7 billion m³ [44 billion bbl] of natural gas liquids—a total of 65.5 billion m³ [412 billion bbl] of oil equivalent (next page). This constitutes about 30% of the world’s undiscovered gas and 13% of the world’s undiscovered oil. Thus, the 2000 USGS estimate has been refined: The undiscovered gas resources are assessed as being even larger, whereas the undiscovered oil resources are only half as much as the earlier estimate.

However, none of the estimates is final for an area as underexplored as the Arctic, and the CARA appraisal induced further interpretations and criticism. On one hand, some believe that the undiscovered oil resources of the Arctic, while critically important to the interests of the stakeholder countries, are probably not large enough to significantly shift the current geographic

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patterns of world oil production.\(^1\) In addition, a postassessment review of the risks that CARA evaluated showed that the Arctic areas, on average, are less likely to hold large fields.\(^1\)

On the other hand, a separate appraisal of the Russian Arctic oil and gas potential suggests that the Arctic basins collectively constitute one of the world’s largest petroleum superbasins.\(^2\) Scientists calculated probabilistic estimates of hydrocarbon resources of Eurasian sedimentary basins in the Arctic Ocean shelves using a stochastic regression relationship between the initial oil-in-place and gas-in-place resources and characterization of the filling of the sedimentary basins, making allowance for their ages. The estimates suggested that, in the second half of the 21st century, the Arctic petroleum superbasin could provide consumers with energy resources that are comparable to those of the Persian Gulf or West Siberian petroleum basins.\(^3\)

Nonetheless, whatever the specific estimates, it is clear that the Arctic petroleum reserves are more than sufficient to attract exploration and create a demand for oilfield services. The following sections describe how companies address the challenges they face in finding and exploiting Arctic reserves.

**Logistics and Environment**

“Cold!” For most people that is the main challenge of working in the Arctic. Indeed, in Arctic areas, uncomfortably low temperatures dominate for a considerable part of the year. To work in the cold, companies must budget additional expenses for everything from warm work clothing and non-freezing fuels and oils to specially designed equipment and vehicles.

However, the Arctic is not always cold; temperatures vary significantly with place and season. The average temperatures in summer are above freezing over all Arctic areas except the central Arctic basin and interior Greenland.\(^4\) In the warmer areas, when temperatures are most comfortable for humans and suitable for machines, the ground is free of snow and ice and unfrozen to varying depths. But the result is that northern taiga, forest-tundra and tundra become almost impassable wetlands during the warm season.\(^5\)

Because of this almost impenetrable landscape and the sparse population, permanent roads are either uneconomical or impossible to construct. The absence of roads is one of the reasons the operational season for many onshore exploration activities is restricted to winter, provided that the temperature drops sufficiently low, down to at least \(-20^\circ C \text{ [} -4^\circ F\text{]}\), for the ground to be frozen hard enough to support heavy trucks and equipment.

Furthermore, it is often necessary to construct ice roads by taking water from beneath the ice of neighboring rivers and lakes and pouring it on the surface. Wherever possible, ice roads are laid along frozen waterways near the roadbuilding material—water. There are special requirements for the thickness and strength of
the ice roads, as well as driving and safety requirements for vehicle operators (above). In addition, ice bridges are built to cross frozen rivers and ponds, and sea-ice roads are constructed on the frozen sea.

All these types of ice routes are used by Schlumberger in the Northwest Territories, Canada, to connect its base in Inuvik to locations in the Mackenzie Delta–Beaufort Sea basin. The southernmost parts of most of the roads are laid along the frozen Mackenzie River, and northward, many rivers and lakes are crossed via ice bridges. On the Inuvik-Tuktoyaktuk road, the northernmost leg is a sea-ice road along the coast of the Beaufort Sea’s Kugmallit Bay.

Another equally important reason for taking care with roads and transport is the extreme fragility of the Arctic environment. Arctic soil, especially in tundra, is particularly vulnerable to damage. Some remnants of seismic exploration activity—trails made by drill, vibrator and recording vehicles—may persist for decades. To allow seismic operations to continue year-round, WesternGeco introduced the first rubber-tracked, low ground-pressure vehicles to Alaska’s North Slope (below). These vehicles have wide rubber-treaded tracks and a new drive system. When making a turn, conventional tracked vehicles lock one track, while keeping the other moving. The locked track drags along the ground, often causing damage. With the new drive system, both tracks continue to move during a turn, but one of them moves faster than the other, reducing potential damage to the soil.

WesternGeco takes other measures to minimize environmental impact. For example, drip pans or sorbent materials are placed beneath vehicles to avoid contaminating the snow with drops or spills of hydrocarbon-base products. These sorbent materials, together with other waste, are then disposed of in an on-site computer-controlled high-temperature incinerator. Another example of attention to detail is the use of wooden stakes instead of plastic and wire-pin flags for indicating source and receiver points in land seismic surveys. Wood, if inadvertently left in the field, will biodegrade much more rapidly. These measures and others significantly reduce damage to the sensitive Arctic environment.

**Exploration Challenges**

Along with infrastructure and logistics challenges, the use of basic technologies in Arctic exploration can be difficult. Results of land seismic surveys everywhere are affected by surface roughness and near-surface heterogeneity. In the Arctic, these problems are exacerbated. Glacial erosion and deposition lead to a complex geomorphology with moraines, lakes, ridges and rapid lithological changes. Thaw areas may induce low-velocity anomalies for body waves, whereas the ice cover may generate flexural waves with large amplitudes and very short wavelengths. In ground with permafrost and seasonally frozen layers, there are often abrupt transitions between the frozen and melted zones. These transitions usually result in large and rapid variations—both vertical and lateral—of elastic properties, inducing seismic arrival-time differences that require corrections, called statics.

An approach that uses instrumentation to cope with coherent noise is point-receiver acquisition, which WesternGeco introduced in 2002 with the Q-Land single-sensor land seismic system. The new-generation UniQ integrated point-receiver land seismic system, launched in 2008, was designed to work in complex-geology and high-noise environments. The UniQ seismic system is compliant with environmental regulations in the Arctic and other sensitive locations.

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^The danger of thin ice. A Super-B-Train truck hauling diesel fuel broke through the Mackenzie River ice crossing near Fort Providence, Northwest Territories, Canada. The truck weighed more than 60,000 kg (132,300 lbm), which is 15 times more than the maximum load limit of 4,000 kg (8,800 lbm) for the Mackenzie River ice crossing. (Photograph courtesy of Jeffrey Philipp, Yellowknife, Northwest Territories, and CBC News, reference 28.)

^A rubber-tracked vibrator. Wide tracks deployed with rubber treads produce less pressure on vulnerable Arctic soil, causing less damage.
WesternGeco performed a point-source, point-receiver test in the Russian Arctic to demonstrate how the effects of near-surface complexities can be identified and removed. The test area was located in a plain, at the border between tundra and taiga. The area is dominated by moraine features and outcrops in rivers, creeks, and glacial lakes. Along with glacial geomorphology features, the main geophysical factor in the survey was temperature, which affected the state and properties of the ground and surface water.

Elastic properties of water change drastically upon freezing, and as a consequence the seismic velocity of unconsolidated sediments may increase from 1,500 m/s [5,000 ft/s] to almost 4,000 m/s [13,000 ft/s]. Therefore, the near-surface properties may vary with the season (right). A thick, permanently frozen layer in continuous permafrost areas is characterized by high seismic velocity. However, in large lakes and rivers, the deeper water, which is insulated by the ice cover, may remain liquid throughout the year, thus forming low-velocity anomalies. Seismic wave propagation in discontinuous and sporadic permafrost areas and in areas with a thick seasonally frozen layer is additionally complicated by transitions between frozen patches and unfrozen zones.

The survey was located at the southern edge of the permafrost area, and continuous permafrost was not expected. However, relict permafrost was likely. Relict permafrost can be extremely heterogeneous laterally, representing the present or past surface drainage system. Imaging this interface by dense sampling in the near offset yielded a useful survey result: Relict permafrost can be a drilling hazard because it can seal underlying natural gas accumulations. Also, relict permafrost has a strong impact on seismic data, inducing large long-wavelength traveltime distortion and often generating strong multiples.

The test data were acquired as point-source, point-receiver seismic data, which allowed the detection and delineation of the extreme lateral variations in the properties of the seismic data. High-resolution refractions revealed the top of the permafrost with a velocity exceeding 3,000 m/s [9,843 ft/s] at a depth of 100 m [328 ft]. The refractions travel as Rayleigh waves in the solid ground and as flexural Lamb waves in the ice (below).

One of the biggest seismic data processing challenges in permafrost areas is long-wavelength traveltime distortion in the shallow part of the section. A number of techniques are used to resolve this effect, but many of them depend on

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31. Permafrost is defined as a soil layer that remains at or below the freezing point of water of 0°C [32°F] for two or more years.
well data. One method that does not require well data or assumptions about geology uses grid-based tomography to build a depth-velocity model of the shallow subsurface. This method was tested for suitability for processing the data acquired in West Siberia, Russia.

The permafrost-induced distortion was corrected in two steps. First, geoscientists built a high-resolution model of the shallow part of the section that contains permafrost. Second, they identified a shallow horizon below permafrost, tied the final depth-velocity model to well data, where available, and calculated replacement statics using either a constant velocity or gradient velocity field above the chosen horizon. The final high-resolution depth-velocity model for the shallow part of the geologic section showed a very good match to the well data (above left). This velocity model can be used for full depth migration or can serve as a basis for long-wavelength statics derivation. In the case from West Siberia, images produced from a model that incorporated the permafrost correction produced geologically realistic horizons, while those derived from the uncorrected model contained sag and bulge artifacts (above right).

Because exploration activities in the Arctic are characterized by high costs and short operating time windows, Schlumberger is focusing on integrating techniques to prioritize exploration targets. For example, PetroMod petroleum system modeling software helps assess basin potential by tracking hydrocarbon generation, maturation and accumulation throughout geologic history. The results are 3D geologic models that are fully scalable from regional to prospect scale. Through such modeling, exploration risk assessments are improved in advance of field operations, and time and effort can be concentrated in the areas with greatest exploration potential, while avoiding areas with lower chances of success.

Schlumberger and the USGS undertook a study combining basin and petroleum system modeling (BPSM) on a regional scale with prospect-scale modeling. This study was intended to help geoscientists understand the petroleum systems in Alaska’s North Slope and the Chukchi Sea—a region spanning vast underexplored territories and areas containing significant known reserves. The study area covered 275,000 km² [106,000 mi²] and included data from more than 400 wells.

Simulation results showed that hydrocarbon charging occurs quickly—instantaneously on a geologic time scale. If traps are not formed before or as soon as hydrocarbons are ready to move, there is a high risk the fluids will not be trapped. Events charts for two different areas overlying the thermally mature Shublik source rock demonstrate how relative timing between trap formation and source-rock maturation can
impact risk (right). At Prudhoe Bay, trap formation preceded generation, migration and accumulation by several million years, resulting in major oil accumulations. On the other hand, the events chart at a well in the foothills of the Alaskan Brooks Range indicates significant timing risks exist for stratigraphic traps, which formed at about the same time as generation and migration of fluids from the Shublik Formation. In addition, risk is high for the structural traps because they can be filled only by remigration of petroleum from older stratigraphic traps or by hydrate displacement from other areas.

Drilling in the Arctic

Drilling in Arctic areas is complicated both onshore and offshore. In both environments, the main subsurface challenge is permafrost, which may be a drilling hazard because accumulations of natural gas hydrates can exist within and beneath it.\(^\text{35}\) A dangerous gas kick may occur when a gas hydrate–bearing layer is penetrated or if free gas is trapped below the gas-hydrate zone.\(^\text{36}\)

Most drilling problems encountered in gas hydrate–bearing strata are attributed to gas-hydrate dissociation, which can produce more than 160 volumes of free gas for every volume of gas hydrate affected. Typically, this can occur if drilling operations or warm drilling mud alters the temperature or pressure regime of the gas hydrates within the formation sediments or within drill cuttings. In situations where the temperature equilibrium of the gas hydrates has been disrupted, conventional well control methods, such as weighting up the drilling mud, may have little effect because the gas is being produced as a result of thermal, not pressure, disequilibrium. In a worst-case scenario, gas-hydrate dissociation may be so vigorous that the drilling mud is displaced, thus reducing the hydrostatic head and creating the potential for an influx of free gas. Drilling problems in the Mackenzie Delta and northern Alaska have been attributed in part to this phenomenon.\(^\text{38}\)

Because of the potential drilling hazard that gas hydrates present, industry practice in most regions typically has been to drill through gas hydrate–bearing strata as rapidly as possible in order to stabilize the interval and install surface casing. However, in Arctic wells, chilled drilling muds have worked effectively to maintain gas-hydrate stability conditions. Therefore, the typical strategy employed when problems are encountered is to slow the rate of penetration and circulate the gas-hydrate cuttings out of the hole. More recently, chemical agents have been added to the drilling mud to stabilize the gas hydrates both in the formation and in the drill cuttings.\(^\text{39}\)

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**Prudhoe Bay**

**Brooks Range Foothills**

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Winter 2010/2011
Drilling operations in Arctic conditions can be improved by using casing while drilling (CWD). This technique employs well casing as a drillstring: The casing is equipped with a drill bit at the bottom, rotated until the target depth is reached and then cemented. In this manner, CWD allows the operator to drill and set casing through problematic zones in one operation with relatively low flow rates to avoid hole enlargement. The lower flow rates also enable use of smaller, lighter rig equipment, reducing the minimum ice thickness required during rig moves, thereby lengthening the winter-season operating period.

Offshore operations in the Arctic encounter the same subsurface difficulties as those onshore, but have more-severe surface challenges. The open-water season is very short, and the conditions are harsh. Strong currents, fierce storms, multyear ice, intense floating ice motion, and, in some areas, icebergs all combine to increase the danger associated with drilling in open water. To withstand such challenges, offshore drilling and production facilities—vessels, platforms and submerged structures—must be particularly rugged. In shallow waters, artificial islands, typically made from gravel or ice, are the most technically and economically efficient solution.

Gravel islands are constructed by dredging and filling with gravel during the summer. In Arctic areas, it is possible to truck the gravel over the ice to the site in the winter and dump the gravel through a hole excavated in the ice sheet. Ice islands lack the stability of gravel islands. The former are relatively thin and tolerate only low-weight loads; therefore, they need to be protected against the lateral movement of the surrounding ice.

Along with artificial islands built from various materials, different caissons, or retaining structures, are used as drilling facilities. For example, in its Arctic activities, ExxonMobil uses gravel islands, ice islands, caisson retained islands (CRI), concrete island drilling systems (CIDS), Molikpaq and single steel drilling caisson (SSDC) systems (above). The CRI structure requires less gravel than a traditional gravel island and is less expensive and faster to install. A CIDS is a reusable gravity-based structure developed to further reduce construction costs. The heavily instrumented Molikpaq drilling and oil production platform is a steel caisson filled with granular material. An SSDC employs an ice-strengthened, converted supertanker that rests on a mobile steel platform, allowing for year-round drilling.

The deeper the water, the larger the earthwork required for building artificial islands and the more costly and more difficult they are to build. An alternative in such cases is extended-reach drilling. The two methods can be efficiently combined. A recent example is the BP Liberty Project, which is estimated to cost more than US$ 1 billion and will tap into a new 100 million-bbl [16 million-m³] reservoir.

The Liberty field is located in 20 ft [6 m] of water inside the Beaufort Sea barrier islands off-shore Alaska. The project will take advantage of existing infrastructure in the BP-operated Endicott oil field, which has been producing since 1987. BP plans to reach the Liberty oil reservoir, about 6 mi [10 km] east of Endicott, using state-of-the-art, extended-reach wells. The wells will be drilled from the Endicott satellite drilling island, which will be expanded for these drilling operations (next page). Producing the oil through these long-reach wells will eliminate the need for a new drilling island and subsea oil pipeline. It is expected that the Liberty field will yield about 40,000 bbl [6,360 m³] of oil per day.

Preparing Arctic Wells
Well cementing in Arctic environments is particularly challenging. Cement setting is usually accompanied by heat release in hydration reactions of cement components. This property of exothermicity, which may be ignored in many other areas, becomes significant in Arctic environments because the heat release causes permafrost to thaw. The formation, previously firm and strong, becomes unconsolidated and unstable as liquid water forms around the borehole. If the permafrost contains gas hydrates, they can decompose to release methane in dangerous quantities. These multiphase conditions around the wellbore threaten its integrity. Because permafrost thickness varies from less than 1 m [3 ft] to more than 1,500 m [5,000 ft], extremely long portions of the wellbore may be damaged if cemented improperly.

Schlumberger developed a solution to this problem—ARCTICSET cements, designed specifically for low-temperature applications across permafrost zones. The compositions of these cements are selected so that the heat of hydration is low and the heat release in cement setting is minimal. ARCTICSET cements do not freeze, but set and develop adequate strength in wells having temperatures as low as −9°C [16°F]. The cements have low free-water separation, low permeability, excellent durability to temperature cycling and controllable pumping times and gel strength properties. An antifreeze is used to ensure that the mix water does not freeze before the cement hydrates. ARCTICSET formulations are available for a variety of conditions, including wellbores that require low-density cements and cements with lost circulation materials.
Harsh, cold climates also pose difficulties for well stimulation operations. Hydraulic fracturing and matrix acidizing share common logistics and environmental safety challenges, but have their own specific difficulties related to handling and storage of supplies, especially chemicals. Hydraulic fracturing is a complex oilfield service: It requires equipment to transport and store water and chemicals, prepare fracturing fluid, blend the fluid with proppant, pump the fluid down the well and monitor the treatment. To operate efficiently in these conditions, Schlumberger engineers designed a fracturing fleet for operations in West Siberia, including Arctic areas.41

41. Some CWD techniques employ a system for retrieving the bottomhole assembly before pumping cement; other systems require the bit to be cemented in place and this option can be further modified by using a drillable bit that can be removed by milling. For more on CWD: Fontenot KR, Lesso B, Strickler RD and Warren TM: “Using Casing to Drill Directional Wells,” Oilfield Review 17, no. 2 (Summer 2005): 44–61.


43. Multyear ice has survived at least one melt season, may be much thicker than first-year ice and typically continues to grow over time.


45. The Molikpaq is an ice-resistant structure originally built to explore for oil in the Canadian Beaufort Sea. It is currently installed in the Astokh area of the Piltun-Astokhskoye field offshore Sakhalin Island, Russia, as part of the Sakhalin II Project. Offshore-technology.com: “Sakhalin II, Sea of Okhotsk, Russia,” http://www.offshore-technology.com/projects/sakhalin/ (accessed December 22, 2010).


Hydration tank

Polymer-storage bin

8 x 6 centrifugal pump

Hydration tank

GelSTREAK polymer hydration unit, fully winterized for the West Siberian climate. Unlike previous continuous-mix systems, the GelSTREAK unit uses dry polymer to produce linear gel at concentrations up to 6 kg/m³ [2.1 lbm/bbl] and at output rates up to 6.4 m³/min [40 bbl/min]. The onboard storage bin holds 1,810 kg [3,990 lbm] of dry polymer powder. Polymer hydration requires time and fluid shearing. Therefore, the onboard hydration tank has five agitation compartments, each 23.8 m³ [150 bbl] in volume, through which the fluid passes sequentially, providing first-in, first-out flow. Equipment operation is automated and remotely controlled from the FracCAT computer-aided treatment carrier, a part of the PodSTREAK unit.

Built on a Russian six-wheel-drive truck chassis and powered by a 400-horsepower engine, the GelSTREAK gel continuous mixing and hydration vehicle, which is easy to transport, is a compact version of the PCM precision continuous mixer (above).

The unit uses the CleanGEL hydrocarbon-free polymer-base fracturing fluids—refined, fast-hydrating, dry guar that have higher molecular weights than conventional products and therefore impart higher linear and crosslinked gel viscosities, allowing a 20% polymer-concentration reduction. Using less polymer is beneficial because less filtercake is deposited on the fracture face, and the proppant pack contains less polymer residue after fluid cleanup. Schlumberger has developed a simplified and robust fluid that is compatible with Siberian fluid-preparation logistics and climate—the YF100RGD crosslinked, water-base fracturing fluid. In this fluid’s name, RGD is an acronym for “reduced guar, delayed,” meaning that less guar is required to attain a given fluid viscosity, and that crosslinking is delayed to reduce friction pressure during fluid placement.

The linear gel produced in the GelSTREAK vehicle is fed to a winterized PodSTREAK stimulation blending, monitoring and control unit. This unit allows continuous mixing of all chemicals required for the fracturing treatment, and an operator in its cabin controls the operation.

Systems have also been designed for matrix acidizing in a Russian Arctic oil field. Field operator Total determined that a well was underperforming in its Kharyaga field in the Timan-Pechora region of Russia 60 km [37 mi] north of the Arctic Circle. The field produces principally from a Devonian-age carbonate reservoir. The productivity index of the subject well dropped to 2.5 m³/(kPa·s) [1.1 bbl/d/psi] from the previous 6.5 m³/(kPa·s) [2.8 bbl/d/psi]. In this well, deviated by 40° at the pay zone, the total length of the perforated interval was 40 m [131 ft], and the bottomhole static temperature was 42°C [107°F]. The permeability of the formation ranged from 20 to 150 mD. The 40 degree API gravity oil had high paraffin content (17% n-paraffins) and a wax-appearance temperature of 29°C [84°F], which raised concerns about compatibility with treatment fluid as well as solidification. Exacerbating conditions included low-temperature surface environment, long perforated intervals, flowback through an electric submersible pump (ESP), and H₂S presence in the oil. Planned workover operations would not allow immediate flowback, and therefore the client selected a polymer-free solution to avoid formation damage.

Total chose VDA viscoelastic diverting acid for even distribution and the DAD dynamic acid dispersion system for acid stimulation. VDA fluid can be used in a wide temperature range, maintaining an ideal thin consistency while being pumped into the well. Upon acid spending, the...
Changing rheology of VDA viscoelastic diverting acid. The VDA fluid in 20% hydrochloric acid has a viscosity of less than 3 mPa·s (left). Upon reaction of hydrochloric acid with formation carbonate rocks, VDA fluid develops viscosity rapidly, and after completion of the reaction, it converts to a gel (right).

A mutual solvent was pumped as a preflush ahead of the acid treatment. Then, VDA fluid was bullheaded alternately with DAD fluid. The DAD acid-external phase emulsion includes a dispersing and stabilizing agent often used as a preflush ahead of matrix acidizing treatments. It was used to remove oily paraffinic deposits and to simultaneously dissolve acid-soluble minerals (below left). The well was flowed back 14 days later without incident, and the restored productivity index was measured at 4.6 m³/(kPa·s) [2.0 bbl/d/psi], which represented an 84% improvement.

A sample of carbonate rock etched by DAD dynamic acid dispersion treatment. The acid enhances permeability by creating large conduits that facilitate the flow of oil.

Arctic Petroleum and Economic Challenges

Although aspects of technology, climate and environment affect Arctic hydrocarbon production, its potential is ultimately determined by a cumulative factor—profitability. The Arctic holds a disproportionate amount of the world’s undiscovered gas and oil. Although these reserves occur in a favorable concentration, they are mostly stranded; the situation is even more difficult for gas because it is more problematic to transport than oil.

The development of liquefied natural gas (LNG) technologies has made natural gas increasingly available for remote consumers, but the advantage of this technology has so far mainly been realized by LNG plants built in low and middle latitudes. Of the 21 operating LNG plants, only one, on the island of Melkøya, Hammerfest, Norway, is in the Arctic; others at Kenai, Alaska, and Sakhalin Island, Russia, are located in similarly harsh climates.

Nonetheless, the determining factor for the future of Arctic oil and gas development seems to be the world’s growing demand for energy. The satisfaction of that demand may require marshalling all conceivable hydrocarbon resources, wherever they are located. Continually improved technologies may help bring the hydrocarbons of the remote Arctic within reach of consumers worldwide.

—VG