FEB
10
V01

brBR

BIG RISK, BIGGER REWARDS

FEATURED INSIDE

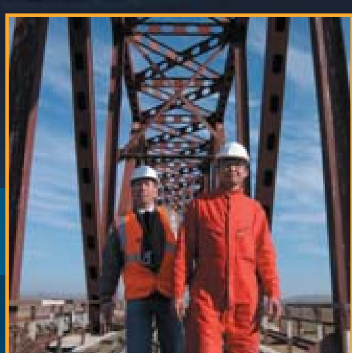
ExxonMobil's challenging Point Thomson project

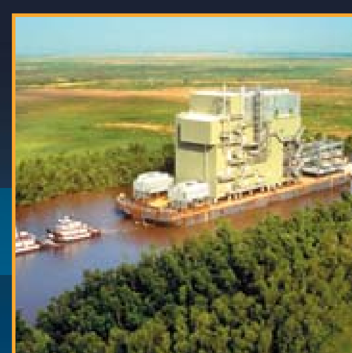
What Alaska has to offer oil and gas companies, investors

Life expectancy of trans-Alaska oil pipeline climbs as it ages

A special publication from Petroleum News

Petroleum news





CONTENTS

Big Risk, Bigger Rewards

Released Feb. 12, 2010

BIG RISK, BIGGER REWARDS is a special annual supplement to Petroleum News, which is owned by Petroleum Newspapers of Alaska LLC.

MAILING ADDRESS:
PO Box 231647
Anchorage, AK 99523-1647
Phone: (907) 522-9469
Fax: (907) 522-9583
Email:
circulation@PetroleumNews.com
Web page:
www.PetroleumNews.com

To order additional copies of this special publication, contact Clint Lasley, Petroleum News general manager and circulation director, at clasley@petroleumnews.com

Cover photo: Courtesy ExxonMobil

Printed by Journal Graphics, Portland, Oregon

CONTENTS

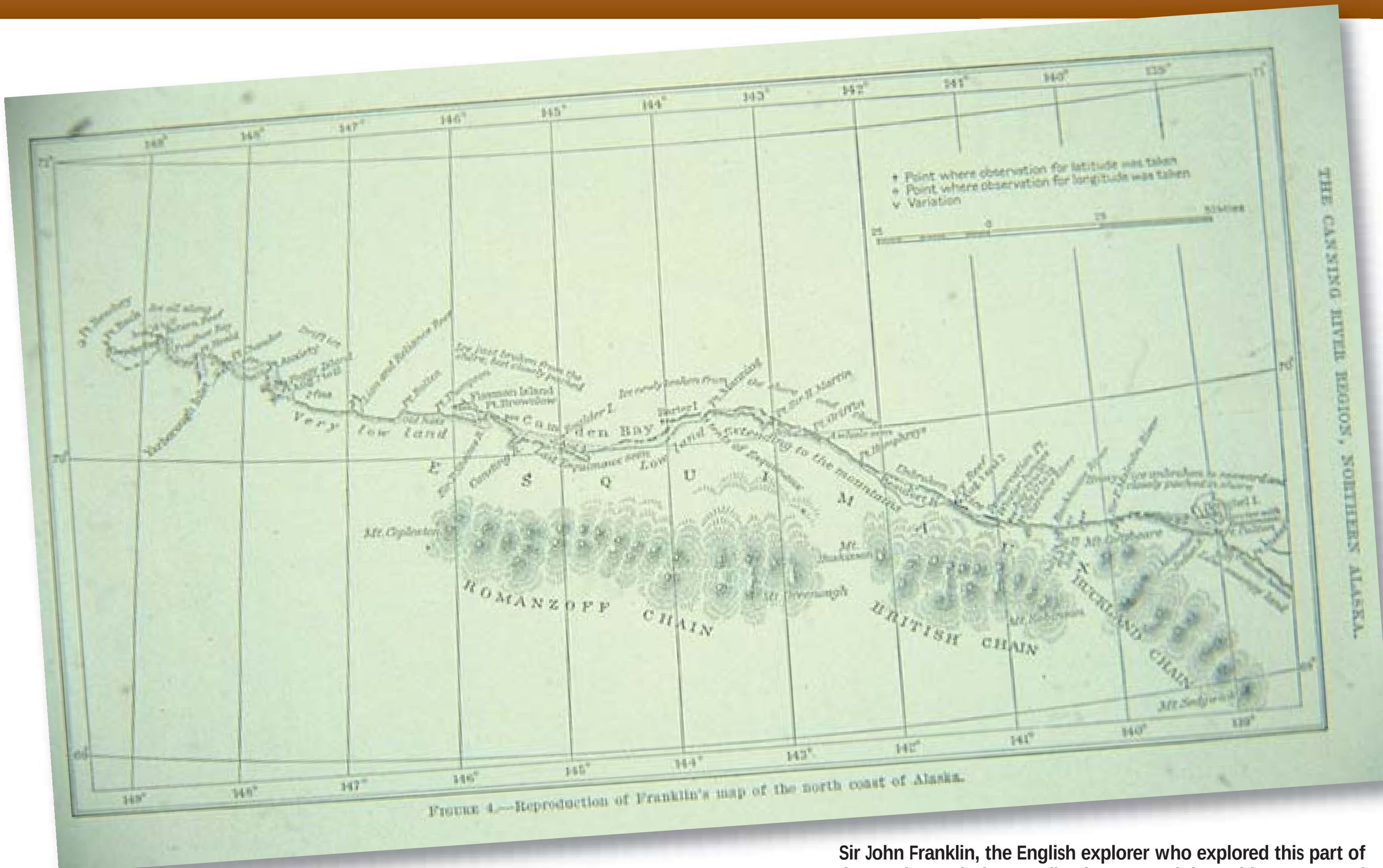
26

45

76

48

Section 4, Alaska's geology and exploration trends, is reprinted from The Explorers 2009 magazine, which was largely written in October 2009.



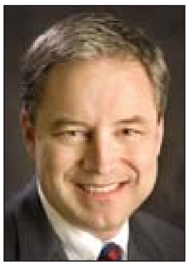
Sir John Franklin, the English explorer who explored this part of the northern Alaska coastline in 1825 and drew this map named Prudhoe Bay after his friend, Baron Prudhoe. Courtesy Gil Mull.

Alaska remains a sure, sound choice for America's future energy needs

America needs energy, and it needs to become more self reliant

By Gov. Sean Parnell

Alaska, like the rest of our nation, sits at an energy crossroads. In the coming months our country and its largest state will make crucial decisions about how to address their energy needs. The right choices will open up new domestic oil and gas developments to meet increased U.S. energy demands and will reduce our country's reliance on foreign energy. For Alaskans, making the right choices would mean more energy to meet in-state energy needs, more jobs, and a stronger state economy.



Sean Parnell, Governor, Alaska

Fifty years ago, when Alaska gained statehood, the right choices were made. At that time, Alaska committed to become self-sustaining and to contribute to our country through the wise and responsible development of Alaska's abundant natural resources. After statehood, we worked alongside the federal government with some of the best companies in the world to fulfill the promise of responsible resource development.

Alaska's territorial residents understood our state's oil and gas potential. After the Mineral Leasing Act was adopted in 1920, the federal government set aside 23 million acres on the north coast of Alaska, called the Petroleum Reserve No. 4. This reserve, renamed the National Petroleum Reserve-Alaska, or NPR-A, in 1980, is believed to hold 12 billion barrels of oil and 73 trillion cubic feet of natural gas.

Anchorage Daily Times

RICHFIELD HITS OIL

PRODUCTION CHIEF FLIES HERE

Dulles Pleads For World Disarming

Lake Iliamna Blaze Nearly Under Control

Alaska Talks, Thinks Oil As Predictions Spread

Top Oil Man Called Here

Lease Filing Rush Starts

A July 23, 1957 news article with the headline "Richfield Hits Oil" in the Anchorage Daily Times proclaims the discovery of the Swanson River oil field on the Kenai Peninsula that kicked off the Alaska oil boom, over 10 years before the Prudhoe Bay discovery. Photo courtesy Gil Mull

Oil at Swanson River

At the time of statehood, oil had been discovered at the Swanson River on the Kenai Peninsula by Richfield Oil Co. Within two years, Unocal had discovered a natural gas field in the same area. In 1962, oil and gas were discovered in the Middle Ground Shoal near Port Nikiski, leading to the construction of numerous wells in Cook Inlet and an economic boom for the Kenai Peninsula.

At the same time, the discovery of oil and

continued on next page

CHOICE *continued from page 7*

gas at Prudhoe Bay, the development of our world-class oil fields on Alaska's North Slope, and the construction of the trans-Alaska oil pipeline system served as a tremendous boost for our nation's economy. Oil production through TAPS began in 1977, and in 1988, production peaked at 2.1 million barrels of oil per day, representing nearly 24 percent of the nation's crude production. Although production is down to 700,000 barrels of oil per day, Alaska still produces 14 percent of U.S. oil production.

North Slope oil proved to be economically beneficial for Alaskans, creating good jobs and increasing state revenues. Historically, the royalty, tax, and lease payments from oil and gas production have provided approximately 90 percent of Alaska's unrestricted state revenue. In recognition of these revenues, the State of Alaska coupled its commitment to responsible resource development with the decision to create a permanent fund to responsibly manage Alaska's share of its oil and gas resources. The fund is a multibillion-dollar savings account, providing surety for the State of Alaska to weather tough economic times.

Today's opportunities

Today, we have another opportunity to make good choices for our nation and our state. These choices involve understanding our options and opportunities in areas like the North Slope and Cook Inlet, exploring opportunities in the foothills and Interior basins of the state, and supporting responsible development off the coast of Alaska, within Alaska's Outer Continental Shelf.

Significant progress has been made to slow the decline in oil production. BP is preparing to drill its Liberty Project, utilizing the longest directional drilling mechanics ever employed by any producer. Other efforts to protect oil production levels include BP's work targeted to produce North Slope heavy oil, the success of Pioneer with permitting and construction at the Oooguruk offshore field, Eni's efforts to develop Nikaitchuq and ExxonMobil's development of two wells at Point Thompson — the first since the 1980s.

In 2007, the Alaska Legislature, in concert with the Executive branch, passed legislation to incentivize a project aimed at commercializing the North Slope's known gas reserves. Alaska created a framework for moving a gas pipeline forward by creating incentives and requiring performance in return. Specifically, the state would invest in the development costs for designing a line and allow the project sponsor to negotiate a deal with potential gas shipping companies. TransCanada, in a competitive process, won the right to the state's incentives. Among other things, TransCanada has committed to obtaining a certificate of public convenience and necessity from the Federal Energy Regulatory Commission to sanction construction of the proposed pipeline. This project provides an excellent opportunity to monetize Alaska's gas resources and to provide for in-state energy needs. My most recent budget proposes authorizing $156.5 million in FY2011 to further that goal.

Infrastructure needed

There are also exciting prospects for developing oil and gas in the foothills and Interior basins of our state. To do so will require an investment in transportation infrastructure to provide access to those resources. To that end, this year's budget also includes $8 million to the Alaska Department of Transportation and Public Facilities for the "Road to Resources" effort. The "Road to Resources" program includes an aggressive transportation plan to build a road from the Dalton Highway, west to Umiat, in order to access both the known and the prospective oil and gas reserves in this area. Building this road will provide year-round access to the Umiat oil field and Gubik gas complex. It will also allow for the placement of seasonal equipment on the doorstep of the NPR-A. Umiat is believed to contain 250 million barrels of economically recoverable sweet oil.

All of these options have great potential to create jobs for Alaskans, provide a steady and affordable source of energy for Alaska homes and businesses, attract new business and exploration in Alaska, and create new sources of revenue for the state.

Alaska's OCS

Looking beyond our border, making the right choices will allow Alaska to continue its contribution to our country's resource needs through production of our abundant North Slope natural gas, and through the development of the vast reserves of oil and gas located off Alaska's OCS. We live in a time of both economic promise, and peril — something all of us endure as our nation works to recover from a severe recession and a mounting federal deficit.

America needs energy, and it needs to become more self-reliant. These two needs can be addressed by the promise of Alaska oil and gas. Tremendous resources still underlie state lands in Alaska, but as a state, we also encourage development of the vast resources on federal lands, and offshore. We applaud the U.S. Department of Interior's decision to hold a lease sale in the National Petroleum Reserve-Alaska in 2010, and strongly support development of the OCS off the coast of Alaska.

Consider that over TAPS' 30-year lifespan, 15.5 billion barrels of oil have flowed through it. By some estimates, at least that amount of oil can still be recovered on the Slope, thanks to improvements in technology that will allow production of heavier crude. Prudhoe Bay has at least 24 trillion cubic feet of natural gas, which has largely been injected back into the ground for storage, and to increase oil production from the field. Point Thomson, located between Prudhoe Bay and the Arctic National Wildlife Refuge, is Alaska's largest undeveloped oil field with the potential to contribute hundreds of millions of barrels to TAPS throughput. It is also thought to contain trillions of cubic feet of natural gas. The prospect of building a natural gas pipeline to develop Prudhoe Bay gas — and potentially Point Thompson gas — represents a significant source of natural gas for domestic energy consumption in coming years.

Tremendous potential exists for responsible oil and gas development of the Outer Continental Shelf. According to a 2009 assessment by the Minerals Management Service the OCS has 27 billion barrels of oil and 132 trillion cubic feet of natural gas. Combine OCS reserves with the rest of the state's oil and gas reserves, and Alaska has 30 percent of the nation's recoverable oil and gas. OCS oil could nearly double the amount of oil transported through the TAPS and provide more needed energy for our nation.

USGS assessment

The world-class potential of Arctic Alaska was also evidenced in the 2008 Circum-Arctic Oil and Gas Assessment from the United States Geological Survey, which highlighted that Arctic Alaska is second only to the West Siberian Basin in total Arctic hydrocarbon potential, and has the highest Arctic potential for oil. The USGS study estimates that Arctic Alaska (state and federal lands, and offshore) holds technically recoverable resources amounting to 30 billion barrels of oil, 6 billion barrels of natural gas liquids and 221 trillion cubic feet of conventional natural gas.

My administration supports opening the OCS to development because it makes economic sense, and is in the best interests of

Alaska has a strong record of responsible offshore oil and gas development. In over three decades, since 1973, 84 oil and gas wells have been drilled in Alaska's OCS without incident.

our country. Developing the Alaska OCS will create well-paying jobs for Alaskans and other U.S. citizens, reduce energy prices, and lessen the kind of price volatility that contributed to our recent economic downturn. At a time when Americans are concerned about a growing federal deficit, it is important to note that Alaska's OCS leases have generated over $9 billion in revenue for the federal government since 1976, and promise much more if development is allowed to proceed.

Increasing domestic production would also reduce our massive trade deficit, since it would reduce the import of foreign oil. Opening the OCS is an important part of a national energy policy. Developing our own resources means royalties from production will benefit our government rather than foreign governments. It would also advance national security and foreign policy interests, limiting our dependence on imports from regions and countries hostile to the United States and its interests.

Alaskans support a credible national energy policy that includes wise, responsible use of conventional fuels, in addition to development of renewable energy sources, to meet our growing demands. I believe that Alaska's oil and gas resources can, and must, be a major part of the implementation of any of our nation's energy policies.

Challenges

There will be challenges. Some groups will continue to challenge development of Alaska's offshore reserves, claiming that exploration and development in the Beaufort and Chukchi Seas will harm the environment. However, Alaska has a strong record of responsible offshore oil and gas development. In over three decades, since 1973, 84 oil and gas wells have been drilled in Alaska's OCS without incident. During this time period the federal government has spent $300 million studying Alaska's waters to ensure that oil and gas development occurs responsibly.

Alaska has always been a land of promise for the people who live and work here, and for the people of our country who benefit from Alaska's bounty. Alaska wants to contribute more of our natural resources to our nation's security and to meet America's energy needs. We also want to continue the path set at statehood to sustainably provide jobs and resources for our people. Fifty years from now, when Alaskans celebrate our 100-year anniversary of statehood, I want it said that Alaska remained true to that promise. ■

Oil and gas opportunities abound in Alaska

The last frontier has always been a land of opportunity

By Tom Irwin

Commissioner, Alaska Department of Natural Resources

Tom Irwin, Commissioner, Alaska Department of Natural Resources

WANTED: The State of Alaska seeks independent, ambitious and responsible business partners with knowledge of oil and gas industry and dedication to safety and responsible resource development for opportunity of lifetime. Must already work in or be willing to relocate to Alaska. Preference given to businesses that are willing to hire qualified Alaskans. Good corporate citizenship a plus. Pay is competitive. A tremendous benefit package includes exploration investment and other credits. Only serious applicants need apply.

If I were buying space in the classifieds I might use an ad like this to invite producers, shippers and businesses to come to Alaska and support our oil and gas industry. The last frontier has always been a land of opportunity and this will continue to be the case for many more years to come.

Alaskans have a very special relationship to our environment. The land is our back yard. We use it for recreation and subsistence. The land provides our livelihood. Alaska is a land of amazing natural beauty, and the resources that underlie that beauty sustain our economy. Our founding fathers worked hard to protect Alaska's land and resources. Responsible development, sustainable yield and resource stewardship were written into the state's constitution and our laws.

Early discoveries

When Alaska was a newly minted state, Alaskans understood our state's potential resource bounty. Responsible companies with a nose for oil and gas and the willingness to invest time and money into exploration discovered an oil and gas bounty on the Kenai Peninsula's Swanson River, in the shallow waters of Cook Inlet, and on the state's North Slope.

In 1977 construction of the 800-mile trans-Alaska oil pipeline system was completed. TAPS is an engineering marvel that crosses three mountain ranges and connects Prudhoe Bay and the North

Slope to the beautiful community of Valdez in Prince William Sound. TAPS production peaked at 2.1 million barrels of oil per day in 1988, transporting nearly 24 percent of the nation's crude oil production. Today production has declined to 700,000 barrels of oil per day, yet Alaska still produces 14 percent of U.S. oil production.

Though Prudhoe Bay oil production is slowing, as long as oil is flowing, the TAPS will not be tapped-out. New opportunities exist that can extend the working life of the 48-inch pipeline. These opportunities include the National Petroleum Reserve-Alaska, Point Thomson and Alaska's Outer Continental Shelf.

The NPR-A, located west of Prudhoe Bay, is believed to hold 12 billion barrels of oil and 73 trillion cubic feet of natural gas. Sandwiched between Prudhoe Bay to the west and the Arctic National Wildlife Refuge to the east is the Point Thomson field. Point Thomson is believed to hold hundreds of millions of barrels of oil and up to 8 trillion cubic feet of natural gas.

15.5 billion barrels produced

Over its 30-year life Prudhoe Bay has produced 15.5 billion barrels of oil. By some estimates the field is still believed to hold nearly that same amount of oil, much of which is heavy crude that for years was either too challenging or too expensive to develop. Today, through research into new recovery techniques by BP, that oil may soon be available for production. In addition to oil, the Prudhoe Bay field holds 24 trillion cubic feet of natural gas. To date, gas produced at Prudhoe has primarily been re-injected into wells to pressurize the field to enhance oil recovery. A small portion of that gas has been used to provide power to facilities in the area.

But as the man in the infomercial says, "That's not all."

On several occasions Gov. Sean Parnell has expressed his support for responsible development of Alaska's Outer Continental Shelf. In a 2009 assessment the MMS estimated that the OCS contains 27 billion barrels of oil and 132 trillion cubic feet of gas. I wholeheartedly concur with Gov. Parnell that it is critical to develop this resource for the benefit of Alaska, and our nation. To put things into perspective, the OCS alone holds almost twice the amount of oil that has been recovered at Prudhoe Bay and has five times the amount of gas. Bringing the OCS on line would be an economic bonanza for the state and our nation, and equally important, could add significant life to TAPS.

Exploration plan supported

Recently I notified John Goll, the regional director of the MMS, that I fully supported Shell's proposed 2010 OCS Lease Exploration Plan in the Beaufort Sea. Shell has voluntarily taken action that significantly modifies the company's exploration plans, spent $25 million retrofitting its drilling ship with the best available technology to reduce air emissions, reduced ocean discharges for drilling operations to 1 percent of what is currently allowed in the Beaufort Sea, and has committed to reduce vessel activity to accommodate North Slope whalers looking to meet their harvest quota. I applaud Shell's efforts because the company is acting in a responsible manner in its approach to exploration. This is especially important given the concerns raised by certain groups that repeatedly turn to litigation as a means for shutting down all oil and gas activity in the Beaufort and Chukchi Seas. It should be noted that 84 wells have been successfully and safely drilled in Alaska's OCS.

Most everyone is familiar with the names of the largest oil and gas corporations doing business in Alaska: ExxonMobil, BP and

JUDY PATRICK

The trans-Alaska oil pipeline

ConocoPhillips. In recent years several other smaller companies decided to respond to the ad to do business in Alaska.

In 2008 Pioneer Natural Resources became the first company to join with BP and ConocoPhillips as an operator on the North Slope producing oil from its offshore Oooguruk unit. The unit is in the Beaufort Sea, northwest of the Kuparuk River. The unit is expected to produce over 100 million barrels during its lifetime. Eni also owns a 30 percent interest in the field.

Italian energy giant Eni has acquired a 100 percent interest in the Nikaitchuq field, located offshore of Alaska's North Slope. This project involves the drilling of 80 wells, which will be tied back to the production facility at Oliktok Point. At the time the acquisition was announced production was anticipated to reach 40,000 barrels of oil per day. Their investment will total nearly $1.5 billion.

Foothills, Kenai exploration

Two years ago Anadarko and its partners, Petro-Canada and BG,

continued on next page

CHALLENGE *continued from page 11*

conducted exploratory work in the Foothills region of the Brooks Range south of the North Slope. Anadarko is in the process of evaluating natural gas prospects in the Gubik Complex. Because transportation costs often place limits on the ability to develop our resources, Gov. Parnell asked for $8 million in his proposed FY2010 budget for the Department of Transportation in support of the "Road to Resources" effort. This project would fund construction of a road from the Dalton Highway west to Umiat, crossing a number of additional potential gas fields.

Farther south, in Southcentral Alaska, Armstrong Cook Inlet LLC took over as the operator of the North Fork gas unit. The North Fork gas field is anticipated to provide infrastructure extensions into the Southern Kenai Peninsula. Expanding the Southcentral gas market will provide additional investment incentive to successful gas explorers.

In addition to opportunities on the Kenai Peninsula there are opportunities offshore. In December the Department of Natural Resources' Division of Oil and Gas released a comprehensive geological study that announced that there is sufficient gas in Cook Inlet to supply Southcentral Alaska and the Railbelt for the next 10 years. The study is only the first part of an analysis intended to show that there is still a significant amount of gas in Cook Inlet. I requested that this study be done as part of an ongoing effort by the state to evaluate energy opportunities in the coming years. I believe that it is prudent to explore for and develop gas reserves in this area. Companies interested in natural gas development in Cook Inlet should examine these economic opportunities and challenges.

Staying the course

The last opportunity I wish to address, but by no means the least, is the need for Alaskans to stay the course on the development of a major natural gas pipeline connecting the North Slope to Alberta, and the possibility of a spur line to Valdez. Three years ago this project was nowhere. Today, undeniable progress has been made to achieve an Alaska gas line. Despite near unanimous legislative support for the Alaska Gasline Inducement Act, there were some people who were concerned that no one would commit to take on this project and that no potential shipper of gas would be interested in exploring the possibility to commit gas under the framework of this legislation. The naysayers were wrong.

Today, TransCanada — the premier pipeline company in North America in sub-arctic pipeline construction and design — has undertaken this opportunity. ExxonMobil, one of the premier energy companies in the world, has agreed to partner in the effort to advance the Alaska Pipeline Project to open season. This important infrastructure is the future for Alaska's economy and represents the next amazing investment opportunity for energy explorers. Literally hundreds of trillions of cubic feet of natural gas underlie our North Slope waiting to be commercialized by willing investors. I encourage readers to learn more about this important project by visiting us online, at: http://gov.state.ak.us/agia/.

I would refer you once again to the advertisement at the beginning of this article. It is clear that Alaska possesses the incredible resources to attract oil and gas development in our state. It is also clear that there are companies that are taking advantage of these opportunities. The last question is, "Why?"

In order to induce interest, the state has worked hard to improve the investment climate. Companies that explore in Alaska have the opportunity to obtain exploration incentive credits that can be used, transferred or carried forward. These credits can amount to 30-40 percent of remote drilling costs and seismic work.

There are other economic benefits for potential shippers that wish to commit gas to the Alaska Pipeline Project. For those taking capacity in the initial open season, there will be no change in gas taxes for 10 years and there will be increased certainty on royalty valuation. Once operational, the Alaska Pipeline Project will conduct open seasons every two years to solicit need, expand if sufficient need is demonstrated, and provide the lowest commercially reasonable rates for gas producers.

Timing of gas development

Like most significant events there is also a timing aspect to why people, companies and organizations make a decision about "why" to take action. For Alaska natural gas the timing for development could not be any better.

North Slope natural gas is tapped and ready for commercialization. It has been a critical component for the producers to pressurize oil fields to manage and develop crude oil. With oil production in these fields in decline that gas needs to be monetized — that's just common sense and good business. Natural gas is a key tool in meeting our future energy needs. Energy companies are utilizing the newest technologies to access gas deposits that were once uneconomical or too difficult to reach.

Mark Williams, an energy writer for The Associated Press, wrote an interesting article on the topic of natural gas on Dec. 21, titled, "Gas could be the cavalry in global warming fight." The article addresses the important and emerging role of natural gas to generate electrical power. If you read the tea leaves you will notice that energy companies are very aware of the importance of natural gas. William's article refers to ExxonMobil's recent acquisition of XTO Energy. This purchase will make Exxon the country's leading producer of natural gas.

The fact of the matter is that natural gas may well be the next big thing. Our country has a significant amount of this resource, but Alaska gas is ready to go. The field infrastructure is in place, gas is clean to burn and cleaner to develop. I truly believe that the timing is right for Alaska. It's time to answer Alaska's ad! ■

Savant ahead of schedule at Badami

Denver independent has completed ice road in preparation for completing Red Wolf well and drilling Badami horizontal sidetrack

By Kay Cashman & Alan Bailey

Savant Alaska has completed its 27.5-mile ice road from the eastern end of the North Slope road system to the Badami field, in preparation for the company's winter drilling program at Badami, Savant executive Greg Vigil told Petroleum News Jan. 6. The company plans to finish an oil exploration well it began last winter in the Denver independent's Red Wolf prospect, in the western part of the shut-in Badami unit.

GREG VIGIL

The ice road, begun on Dec. 3 and completed on Jan. 4, followed an inland route that enabled road construction to be finished 70 days earlier than the road on sea ice that Savant constructed in 2009, thus substantially increasing the length of the winter drilling window, Vigil said. The inland route has avoided the problems with thin ice, storm surging and rerouting for polar bear dens that Savant had to contend with last winter.

Cooperative effort

But the cooperation and efficiency of everyone involved in the road construction also contributed to this year's rapid progress, Vigil said.

"One significant factor that contributed to our early, safe and environmentally compliant completion of the tundra winter road was the professionalism, responsiveness and cooperation of the various regulatory personnel at the Alaska Department of Natural Resources and the North Slope Borough in their review, processing and authorizations of the numerous permits, amendments and administrative approvals necessary to conduct the work," Vigil said. "Our contractors, CH2M Hill and Cruz Construction, also did an excellent job in constructing the road ahead of schedule and on budget."

Doyon Rig 15 at Deadhorse on Alaska's North Slope.

SAVANT ALASKA

As part of a 2008 farm-in deal with BP to improve oil recovery rates at Badami, which BP temporarily shut down in 2007 because of exceedingly low production rates, Savant also plans to drill Badami's first redevelopment well this winter.

All drilling is being done from Badami's single, compact pad, B1, which also holds the unit's production facilities.

The Red Wolf B1-38 well is primarily targeting oil in the Middle Ellesmerian Kekiktuk formation, a deeper and older geologic formation than the Brookian turbidite sands where previous Badami development by BP occurred from six vertical and near-vertical wells.

The redevelopment well will be a sidetrack to BP's existing B1-18 vertical well, utilizing horizontal well construction

Depending on "observed results" Savant might prepare for a

continued on page 15


Where the road ends...
Our Work Begins

Tundra winter road (ice road) near Mile Post 10.

SAVANT *continued from page 13*

well production test or for a hydraulic fracture treatment at a later date, Vigil told Petroleum News Dec. 16.

Just 2,600 feet left to drill

This winter's ice road inland route, which starts 10 miles east of Prudhoe Bay at the edge of the causeway to the Endicott oil field and roughly follows the Badami pipeline corridor, not only adds time for drilling at the beginning of Savant's program, but also reduces the risk of having to wrap up operations ahead of schedule at the end of the season, which Savant had to do last spring due to unusually warm weather that caused early breakup along the Sagavanirktok River, over which ran Savant's 2008-09 ice road — a road it built and shared with ExxonMobil for that company's Point Thomson operations east of Badami.

Last winter Savant drilled its Red Wolf exploration well to a measured depth of 12,835 feet and set intermediate casing.

"This winter we have approximately 2,600 feet left to drill to test the

continued on next page

SAVANT *continued from page 15*

Kekiktuk formation," Vigil said.

BP's highly efficient Endicott field produces oil from the Kekiktuk, and Red Wolf is down-trend from BP's Beaufort Sea, 100 million-barrel Liberty project, in the same fault block as Liberty's discovery well.

In a January 2009 interview with Petroleum News, Vigil said Savant's "most likely reserve estimate" for the Kekiktuk accumulation was 45 million barrels.

Initially, before it ran into technical production problems with the highly compartmentalized Brookian reservoir, BP hoped to recover 120 million barrels of oil from those sands, which sit about 2,000 feet above the Kekiktuk.

Shale fracturing technology

Operator BP had hopes of producing 30,000 barrels per day from Badami, but while early production ramped up as expected, it soon fizzled, dropping to only about 1,400 bpd by 2003 and 900 bpd in 2007.

In a 2008 letter, Kevin Banks, director of the State of Alaska's Division of Oil and Gas, said that Savant "is a capable third party based on its experience drilling an Alaskan exploration well (offshore Kupcake well, near Liberty, in early 2008) and applying new fracturing technology in low permeability shales."

Depending on what it finds at this winter's Brookian sidetrack, Savant is looking at combining horizontal drilling with hydraulic fracturing — pumping large volumes of fluid into the ground to crack the formation — to try to improve the oil flow from Badami's Brookian sands.

Hydraulic fracturing has been tried before at Badami, but only on traditional vertical wells.

ACES working well for Savant

As part of its agreement with BP, Savant is evaluating the restart of Badami production, but its investment decisions are influenced by the state's current production tax regime, commonly referred to as ACES. Rumors that changes in ACES, Alaska's Clear and Equitable Share, will be considered in the 2010 session of the Alaska State Legislature are worrisome, Vigil said in December. So worrisome that Savant has, for the first time, hired a lobbyist.

The Red Wolf B1-38 well is primarily targeting oil in the Middle Ellesmerian Kekiktuk formation, a deeper and older geologic formation than the Brookian turbidite sands where previous Badami development by BP occurred from six vertical and near-vertical wells

"We've engaged David Parish & Associates, just to make sure our presence is known … to make sure legislators know we are exploring on the North Slope largely because of ACES.

"The state's qualifying capital expenditures and net operating loss credits are paramount to … our exploration effort in Alaska. … They are a great incentive for us to continue to explore in the state," Vigil said.

"Certain ACES provisions are very important and serve their purpose well. Adverse changes to those parts of ACES would not be good for small producers and explorers and are of concern to us."

The company's "Badami plant re-start analysis is particularly sensitive to potential ACES changes," he said. "We can't do an economic model that we can trust if legislative changes are in the works. … The uncertainty increases our risk."

As is, ACES allows smaller producers to have "a severance tax credit if they produce less than 50,000 Btu equivalent barrels a day — the first $1 million per month of severance tax liability is exempt if you are a small producer on the North Slope."

Without that relief and the tax credits, Vigil said, "barring the discovery of new reserves (such as at Red Wolf), the financial risk associated with resuming production from the existing reserves at Badami would be too great."

And the progressive tax rates under ACES would render the Badami work uneconomic, were it not for the fact that the Badami field infrastructure and export pipeline are already in place, Savant said.

Savant Resources, parent to Savant Alaska, is active in the Bakken shale in North Dakota, the New Albany shale in Kentucky and in the Mancos shale in Colorado.

Last winter Savant used Doyon Rig 16 at Badami; in 2010 it will be using Doyon Rig 15. ■

Life expectancy climbs as pipeline ages

With proper maintenance, reasonable costs, conduit for Alaska North Slope petroleum products can flow to tidewater indefinitely

By Rose Ragsdale
For Petroleum News

As the trans-Alaska oil pipeline ages, its life expectancy is actually increasing.

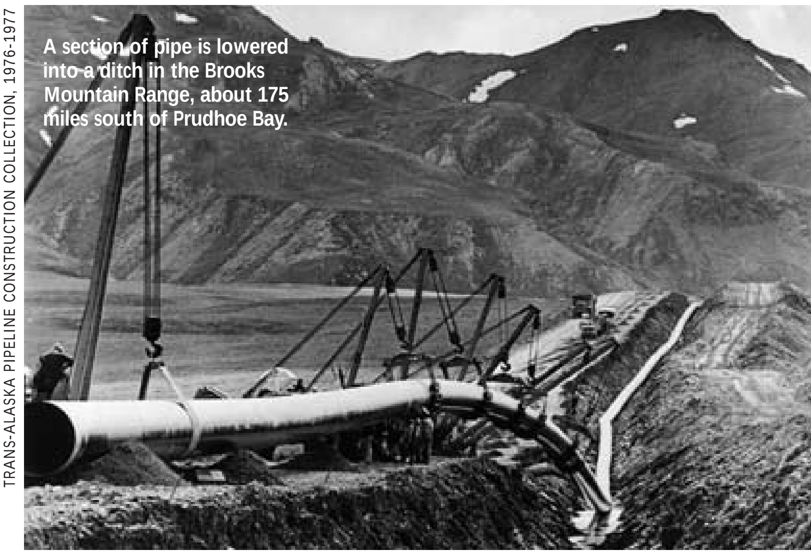
When oil first flowed through the 800-mile conduit in 1977, it was expected to transport crude and other petroleum products from Alaska's North Slope to the ice-free port of Valdez for 35 years or until 2011.

But in 2003, the pipeline got a new lease on life, literally. The federal government renewed its right of way for 30 years, extending the line's apparent life expectancy to 2034.

Operator Alyeska Pipeline Service Co., acting on behalf of the pipeline's owners, poured hundreds of millions of dollars into various upgrades and improvements designed to make the conduit more efficient and less costly.

Dubbed the Strategic Reconfiguration program, the upgrades

continued on next page



TRANS-ALASKA PIPELINE CONSTRUCTION COLLECTION, 1976-1977

A section of pipe is lowered into a ditch in the Brooks Mountain Range, about 175 miles south of Prudhoe Bay.

TAPS *continued from page 17*

took most of the past decade to complete and culminated nearly 35 years of continuous fine-tuning to pipeline operations. The work also coincided with the line's average flow of petroleum climbing from about 300,000 barrels per day shortly after startup to peak at 2.1 million b/d in 1989, before gradually decreasing to average about 700,000 b/d in 2009.

In June, a review board of the State of Alaska's tax division recalculated the pipeline's economic life, projecting its continued operation until the year 2042.

It's all about costs

What's driving this trend toward longevity? In a word: Money.

"As long as you do the maintenance on the pipeline, it's not a physical or a mechanical issue. It's an economic issue," said Jerry Brossia, Authorized Officer for the state-federal Joint Pipeline Office.

Over the years, various forecasts and projections have extended the pipeline's useful life, coming up with a succession of dates that envision the conduit operating for far longer than original estimates.

The pipeline's owners have either agreed with or accepted these extensions without protest. They say the huge oil transportation system, which has shipped more than 16 billion barrels and counting of petroleum, is well maintained and its useful life is entirely dependent upon whether operating it continues to be profitable.

The owners, BP Pipelines (Alaska) Inc., ConocoPhillips Transportation Alaska Inc., ExxonMobil Pipeline Company, Unocal Pipeline Company, and Koch Alaska Pipeline Company L.L.C., cite rising costs as a possible deterrent to the line's continued operation despite recent forecasts calling for at least another 30 years of viable operation. It is costs that are prompting them to seek higher tariffs from shippers on the pipeline, the carriers say.

The shippers, particularly the few that do not have sister companies that own a share of the pipeline, have objected to these sharp increases in the proposed tariffs and taken their arguments to the Federal Energy Regulatory Commission, which regulates interstate tariffs on oil and gas pipelines in the United States.

The pipeline carriers have vigorously defended their proposed tariff increases and the entire issue has evolved into ongoing and complex, multiyear wrangling that is still under regulatory review.

FERC to review life expectancy

After several unsuccessful appeals in 2009, shipper, Anadarko Petroleum Corp., recently succeeded in getting the Commission to reconsider an earlier decision to accept as fact an estimate that the pipeline's useful life will end in 2034.

The FERC, in an order issued Dec. 10, said the shipper presented new evidence that the remaining useful life of the pipeline may extend beyond 2034 and that the issue does require another review.

"Anadarko cites to (the Alaska State Assessment Review Board) June 4, 2009 Certificate of Determination, where the Assessment Board reviewed the determination of the state tax division and found that "the division properly maintained the economic life of the TAPS at 2042," the Commission wrote.

"In addition, the Assessment Board recommended that the tax division 'thoroughly review the economic end life of TAPS every year,' because: [i]t will likely be proper to extend the estimated economic end life of the TAPS past 2042 in future assessments as additional oil reserves on the North Slope become economically extractable or the estimated minimum mechanical throughput of the TAPS is reduced below 200,000 barrels per day," the FERC noted.

The Commission also took note of Anadarko's observation that the pipeline's owners did not object to the state review board's conclusions.

Anadarko cited the following testimony of a "Witness Greeley" at the review board's proceeding:

THE WITNESS: "The Owners approached the Department and said that they were willing to live with the SARB's determination last year regarding two layers of the forecast and the 2042 end of life.

"The analysis the Department did using the two layers, the SARB – the Department adopted the SARB's guidance on the two-layer application. And that analysis coincidently ended up at 2042. That's where it shook out again this year."

Anadarko also argued that the review board's findings were significant because the carriers cited them in recent filings where they proposed much higher interstate tariffs to account for the review board's ruling, which increased the state property tax assessment on the pipeline system; and for costs associated with the strategic reconfiguration program.

The three major carriers, BP, ConocoPhillips and ExxonMobil, filed rate proposals in 2009 that averaged about $1.12 billion, or nearly double the $577 million rate base underlying the 2006 rate that the commission accepted as "just and reasonable" in its Opinion No. 502, issued in June 2008. The 2007 compliance rate accepted by the Commission's April 16 (2009) Order reflects an average rate base of $719.022 million, and the 2008 compliance rate, currently set for hearing, includes an average rate base of

C.G. "GIL" MULL

An aerial view of Pump Station 4 of the Trans-Alaska Pipeline System and the Haul Road at the Brooks Range mountain front, looking north out onto the foothills. Galbraith Lake is in the upper center of the shot.

$889.945 million.

Midcentury mark on horizon?

At least one federal agency, the U.S. Securities and Exchange Commission, was presented with information in 2009 that suggests the trans-Alaska oil pipeline could still be pumping oil to Valdez at the middle of the 21st century.

The BP Prudhoe Bay Royalty Trust told the SEC in its annual 10-K report for 2008, filed in February 2009 that BP Exploration (Alaska) Inc. expects continued economic production at a declining rate through the year 2049.

"… However, for the economic conditions and production forecast as of December 31, 2008, the per-barrel royalty will be zero following the year 2020. Therefore, no reserves are currently attributed to the BP Prudhoe Bay Royalty Trust after that date."

But BP's production plans and expectations for the Prudhoe Bay area oil fields do not necessarily provide an indication of what BP's pipeline operating company will do in the future, according to Brossia.

"The people who produce the oil and the people who transport the oil work for two different legal entities," he said. "The pipeline's owners are dependent on what the FERC and the State of Alaska allows them to charge for transportation."

Because the pipeline is a regulated carrier, its owners must base their operating decisions mainly on how their costs change.

"As throughput goes down, the unit cost for shipping a barrel of oil goes up," Brossia said. "And the people who own the pipeline are starting to question how much money they can make operating it."

He said this can be confusing for the average person on the street to understand. With current high oil prices, it might appear that the pipeline's owners are raking in profits, but that isn't the case. While the carriers are units within their respective oil companies, they must function as separate entities based on their own cost and profit structures while operating a government-regulated transportation system.

"Quite frankly, the FERC and the Regulatory Commission of Alaska have longstanding practices of allowing the carriers a return on their investment of 14 percent," Brossia said. "It's all about money." ■

Perched on the border between state lands and NPR-A, the Alpine discovery, now part of the Colville River unit, drove the decision to reopen federal acreage of the western North Slope to exploration.

The strategy of stepping out at Alpine

At the Colville Rover unit, sequential development gave ConocoPhillips a way to make sure 'big' was also 'big enough'

By Eric Lidji
For Petroleum News

For the time being,"big" in Alaska is a lot bigger than what most people think of as big.

After more than 30 years of oil sales from one of the largest resource basins in North America, the infrastructure network on the North Slope of Alaska is still limited. Without creative solutions, oil discoveries that would be considered gold mines anywhere else in the country can be marginal in northern Alaska. Giants can sit for decades untouched.

Over the past 15 years, ConocoPhillips Alaska and partner Anadarko Petroleum have discovered, developed and continued to expand the Colville River unit, with primary production from the Alpine field. Alpine is the westernmost producing oil field on the North Slope and still one of the larger onshore oil discoveries in North America in more than 20 years.

Alpine is a large field — with more than 429 million barrels in recoverable reserves — surrounded by smaller fields known as satellites that are big, most holding more than 50 million barrels of oil, but not big enough to support the cost of constructing standalone production facilities in the expensive and isolated Arctic.

So over the past decade, ConocoPhillips and Anadarko strategically stepped out production of those satellites. As the Alpine field naturally declined, the companies brought new projects online to make use of capacity at the field's production facilities.

First oil in 2000

Since first oil at Alpine in late 2000, the companies have brought three satellites into production and have concrete plans for several others. If technology gets cheaper, oil prices rise or reserve estimates increase, then the companies could develop many more.

Alpine is a success by many measures.

The fields and satellites produced almost 346 million barrels of oil through the end of October according to the most recent numbers available from the Alaska Oil and Gas Conservation Commission.

For ConocoPhillips, this helped offset production declines at older fields like Kuparuk. For Anadarko, it provided a production base to help fund other operations in the state.

For the state, it brought revenue and bolstered throughput in the trans-Alaska oil pipeline. Alpine production is responsible for the only increase in throughput since peak production in the late 1980s.

The stepping-out approach also promises to open up the National Petroleum Reserve-Alaska, a federal reserve set aside for oil development nearly 90 years ago.

continued on page 22


Casing Running Tool
CRTi
* Connection Make & Break
* Rotate, Reciprocate
* Fill and Circulate
* Rigs in quickly, like making up a drill collar connection
* Easy to understand and operate
* Reduces manpower and equipment requirements
* Improves rig floor safety
* Compact and lightweight tools for easy handling
* Multiple casing diameters with one base tool
* Quick change die structure
* No hydraulic connections means no fluid leaks
Multi Lobe Torque Ring
MLT Ring™
* Works in API Connections "as-is"
* Increases connection torque capacity
* Increases connection compressive capacity
* Smoothes connection transition for tool running and packers
* Reduces the risk of connection washout
* Installs on location, in a storage yard, or in the pipe mill
Casing and Liner Centralization
Centralizers
HydroFORM™
* Solid Centralization
* One piece construction
* Smooth profile
* Reduce torque and drag
* Helical or Straight rib
* Can be Custom designed to suit your needs
VOLANT
OUR EDGE is Innovation
Please contact us at:
4648 Eleniak Road NW
Edmonton, AB T6B 2S1
T 780.490.5185 F 780.437.2187
volantproducts.ca

ALPINE *continued from page 20*

Alpine, though, is not a license to print money.

The partners spent $1 billion just to bring the field online in 2000. That doesn't include a decade of regular maintenance and operations, continued development drilling in an expensive and environmentally sensitive area and a decade of active exploration drilling.

And because of the long lead times in the Arctic, ConocoPhillips and Anadarko have faced two periods of lower oil prices (made up for by a run of increasing prices).

The environmental challenges in the Colville River Delta region around the Alpine field demanded increased protections and considerations that factored into construction.

The location also creates added challenges in terms of land ownership. The unit touches state, federal and Native land. That means more permitting authorities, which can cause delays, force creative partnerships and set up unique tax payments and incentives.

Nestled among the giants

From the start, the North Slope set high standards for the scale required to get a field developed. The Prudhoe Bay and Kuparuk oil fields, online since 1977 and 1981 respectively, are the two largest oil fields in North America. Together, they have produced more than 12 billion barrels of oil, not including their prolific satellites.

Prudhoe Bay justified the creation of major infrastructure on the North Slope, including the trans-Alaska oil pipeline running more than 800 miles to tidewater in Valdez.

Kuparuk created the model for expansion on the North Slope, with independent processing facilities and pipelines leading back to the existing infrastructure grid.

ARCO Alaska discovered Alpine in 1994 and decided the field was commercial in 1996. Along with partners Anadarko and Union Texas Petroleum Alaska Corp., the company proposed a $700 million to $800 million program to build infrastructure and drill 100 to 150 wells. The partners originally estimated that the field contained 365 million barrels of recoverable oil.

Alpine proved attractive not only for the potential size of its reservoir, but also for the quality of its oil. The field produced

ConocoPhillips building ice roads in the National Petroleum Reserve-Alaska

JUDY PATRICK

from Jurassic-aged sandstone not producing anywhere else on the North Slope, suggesting similar fields yet to be discovered. At 40 degrees API, Alpine is lighter than at Prudhoe Bay (26 degrees) or Kuparuk (28 degrees).

Early successes and surprises

As the companies began developing Alpine, the field became more attractive.

First, in 1997 the reserve estimates grew to 429 million barrels from 365 million barrels.

Second, the companies announced the discovery of a field six miles to the north of Alpine called Fiord, which, at an estimated 50 million barrels, would be considered huge by Lower 48 standards, but couldn't support standalone development in Alaska.

Third, the industry changes of the late 1990s hit Alaska. After several years of mergers, acquisitions and government deals, Phillips Alaska (ConocoPhillips since 2002) assumed 78 percent ownership of Alpine, with Anadarko holding the remaining 22 percent. Those ownership stakes have remained since first oil in November 2000.

Alpine sits 80 miles west of Prudhoe Bay, in the Colville River Delta. To develop a major field in the ecologically sensitive area, the companies developed the field with a gravel airstrip and directional drilling from two gravel pads, but without a permanent connection to the North Slope road system, an approach Anadarko described in filings in 1998 as being "like an offshore platform," an approach the companies continued as far west as they could in subsequent years.

During construction, supplies and modules were moved to the site in the winter by ice road.

In filings Anadarko said the construction approach at Alpine shaved 30 percent off development costs, compared to other North Slope projects. The companies also performed considerable work in Alaska, building some of the production modules in Nikiski, on the Kenai Peninsula, work that became a sight to see during the construction period.

In addition to those modules, developing the field required a 34-mile pipeline from Alpine to the Kuparuk River unit, where oil would then flow back to Prudhoe. To avoid a surface crossing of the Colville River, the pipeline is buried beneath the river.

From the start, Alpine required community involvement in a way Prudhoe Bay and Kuparuk did not. The Colville River unit, which includes Alpine and its satellites, was the first significant oil production on Native land allotments in Alaska, and as a result required negotiations with Native corporations in addition to state and federal permits.

For instance, as part of a surface use agreement, ConocoPhillips (then ARCO) agreed to supply 500,000 cubic feet of gas per day to the village corporation of Nuiqsut, a community dependent on diesel fuel priced at a premium because of transportation costs.

Ramping up Alpine production

In filings in 1999, Anadarko named the most attractive features of Alpine: "repeatability" and "running room." The phrases referred to the ability to pile one large oil discovery onto another in a region, using existing facilities, equipment and know-how to reduce costs.

As the companies ramped up Colville River unit production, they also looked for potential satellites to repeat the original work at Alpine on nearby satellite fields.

To avoid duplicating facilities, a cost that would have made additional fields uneconomic, this required not only finding those fields and working to make them commercial, but also timing the startup of those fields to match the changing profile of Alpine.

In its first five years, Alpine production gradually increased.

Brought online in November 2000, Alaska Department of Revenue figures show the field averaged 45,000 barrels per day in fiscal year 2001 (July 1, 2000, through June 30, 2001) and 96,000 bpd in fiscal year 2002.

Anadarko said in filings that the 2001 production from the field was higher than expected.

In fiscal years 2003 and 2004, production averaged 99,000 bpd, rising to 105,000 bpd in fiscal year 2005.

That initial production yielded a rare treat for the state: increased throughput in the trans-Alaska oil pipeline for the first time since peak production in the late 1980s, with total North Slope production increasing from an average of 993,000 bpd in fiscal year 2001 to 1.01 million barrels a day in fiscal year 2002.

Bringing satellites online

During those initial years, ConocoPhillips prepared for the increased production by expanding the capacity at the Alpine producing facilities in a two-phase project in 2004 and 2005. The project gave the companies the ability to produce 35,000 more barrels of crude oil each day and 100,000 barrels of produced water each day.

The increased produced water capacity allowed the companies to manage the changing profile of Alpine. As fields age, the ratio of oil, gas and water produced from reservoirs changes, requiring different handling capabilities.

In 2003, with the expansion project announced but yet to begin, ConocoPhillips and Anadarko filed an application for an Environmental Impact Statement with the Bureau of Land Management that proposed five possible Alpine satellites called Fiord, Nanuq, Lookout, Spark and Alpine West. The companies also hinted at 10 additional oil accumulations within 30 miles of Alpine that could possibly become future satellites.

In the middle of the expansion project, in 2004,

continued on next page

ALPINE *continued from page 23*

ConocoPhillips and Anadarko sanctioned the development of the first two Alpine satellites: the Fiord field discovered in 1999 and the Nanuq field three miles to the south of Alpine discovered in 2001.

The new fields required additional drilling pads. In addition to CD-1 and CD-2 built with the initial development of Alpine, ConocoPhillips eventually built CD-3 for Fiord and CD-4 for Nanuq. The pads are named after the Colville Delta region where production occurs.

Satellite production in 2006

Both satellites came online in 2006 — Fiord in August and Nanuq in December.

Alpine production averaged 123,000 bpd in fiscal year 2006, according to Alaska Department of Revenue figures — the fiscal year peak of annual production for the original Alpine field. In fiscal year 2007, with satellites Fiord and Nanuq in production, overall production through the Colville River unit facilities averaged 124,000 bpd, with 103,000 bpd from Alpine, 11,000 bpd from Fiord and 10,000 bpd from Nanuq.

In 2008, the companies sanctioned a third satellite, Qannik, located in a shallower accumulation above Alpine. That location allowed the companies to develop Qannik not by building new drilling pads, but by expanding the existing pad at CD-2.

Those first three satellites shared traits that eased development. All three sat within the boundaries of the original Colville River unit, which expedited permitting.

All production was through the main facilities at Alpine. A pad and landing strip were built at Fiord — which is a roadless development — and a pad and a short gravel road to the main Alpine facilities at Nanuq.

These appear to have been the easy satellites. Additional proposed satellites in NPR-A to the west of Alpine have proven more difficult for the companies to bring into production.

Further westward into NPR-A

The difficulty and delays the companies face as they press westward is ironic, because Alpine opened a door to NPR-A oil development that had been closed for a decade.

Created by President Warren G. Harding in 1923 as Naval Petroleum Reserve No. 4, the 23 million-acre federally designated reserve in northwest Alaska was meant to preserve an oil-rich section of the territory for the U.S. Navy as it moved away from coal.

The size and remoteness of the region, though, and the fact that as of yet exploration drilling has not uncovered a single, mammoth oil accumulation like Prudhoe Bay, but rather many smaller fields, have kept NPR-A from being developed.

In the 1940s and the 1950s, the U.S. Geologic Survey and the U.S. Navy conducted the first major exploration campaign in the reserve, drilling dozens of wells. While that drilling yielded discoveries, none proved large enough to justify standalone development.

Following the Arab oil embargo in 1973, those parties struck out again through the region, by then known as NPR-A, hopeful for a large accumulation to protect the United States against future embargos or other factors that might drive up oil prices.

The second wave of expeditions, though, fared no better than the first.

In the 1980s, the federal government held four lease sales in the reserve, but companies only nibbled. The lease sales yielded only two exploration wells, and no major finds.

With the sanctioning and development of Alpine, though, federal officials once again looked to open up NPR-A, hopeful for domestic supplies and increased revenue.

A lease sale in 1999 gave Anadarko and the precedent companies of ConocoPhillips drilling rights on a section of federal land just west of the Colville River and Alpine.

In the decade since, ConocoPhillips has been the most active explorer in NPR-A, drilling 20 exploration wells, but its best prospects date to work done in the early years of the exploration program.

NPR-A 1999 leasing

NPR-A development was temporarily complicated in April 1999 when BP announced its purchase of Atlantic Richfield, including the company's ARCO Alaska assets.

BP and ARCO were opposing bidders at BLM's May 1999 NPR-A lease sale.

ARCO Alaska, bidding in partnership with Anadarko Petroleum, had more than $55 million in high bids ($70.6 million for the partnership). BP — bidding by itself and in two partnerships one with Phillips Petroleum and one with Phillips and Chevron — had a hand in more than $32 million in high bids.

Phillips Petroleum, bidding by itself and in the two partnerships with BP, had more than $7.3 million in high bids.

Exploration drilling began on the NPR-A prospects in the winter of 2000.

Both companies permitted exploration wells.

ARCO spud Clover A about five miles west of Nuiqsut in March 2000 and Rendezvous A another 10 miles deeper into the reserve in early April. During the same time, Phillips spud Spark 1 and the Spark 1A sidetrack just northeast of Rendezvous A in March and April.

Ownership issues were resolved in March 2000, when Phillips Petroleum announced that it was purchasing ARCO's Alaska assets.

Drilling near and far

The Alaska operation, Phillips Alaska (now ConocoPhillips Alaska), focused extraordinary attention on NPR-A, staking dozens of wells, accumulating numerous potential drilling prospects and even announcing the first discoveries in the region. Of the six wells and a sidetrack the company drilled in 2000 and 2001, all but one found hydrocarbons.

"These discoveries mark an important milestone in the Alaska oil industry," Kevin Meyers, then president of Phillips Alaska, told the Alaska Oil and Gas Association at its annual luncheon in May 2001. "Though the results are preliminary, we're confident the discoveries will prove to be of commercial quantities. We believe that the five successful wells have encountered three separate hydrocarbon accumulations."

The discoveries propelled the continued flood of activity. Phillips and Anadarko drilled four NPR-A wells in the winter of 2002, and staked another eight that summer.

ConocoPhillips drilled only one NPR-A well in the winter of 2003, the Puviaq 1. The well was truly a frontier wildcat, located near the Ikpikpuk River nearly 80 miles from Nuiqsut.

For the next four seasons, ConocoPhillips continued to craft exploration programs with a mix of frontier wells and delineation wells near existing infrastructure and discoveries.

This near and far approach continued. In March 2004, ConocoPhillips drilled Carbon 1, Scout 1 and Spark 4, all within 10 miles of the discoveries made in 2000 and 2001. In the winter of 2005, the company drilled Kokoda 1 and Kokoda 5 about 50 miles west of Nuiqsut.


The Pioneer well in the NPR-A was drilled by the Doyon 141 rig for ConocoPhillips.

JUDY PATRICK/COURTESY OF CONOCOPHILLIPS

The following winter, ConocoPhillips didn't drill in NPR-A at all. But in early 2007, the company drilled two wells in a partnership with Pioneer Natural Resources: Noatak 1 just north of the Kokoda wells, and Intrepid 2 south of Barrow on the far western edge of the North Slope, more than 200 miles from the closest infrastructure at the Alpine field.

Noatak and Intrepid both cost around $60 million to drill. That combined with the considerable distance to the Alpine infrastructure meant either well needed to find large reserves to justify the

continued on next page

ALPINE *continued from page 25*

significant cost of developing the prospects and tying them back to existing facilities. ConocoPhillips deemed both wells "noncommercial" in May 2007.

Noatak and Intrepid offer a glimpse at the risks at play in Alaska, where more than $100 million in exploration costs can mean an oil discovery that never leads to production. In the winters that followed those wells, ConocoPhillips drilled much closer to Alpine.

ConocoPhillips is not drilling exploration wells on the North Slope this year.

Some industry groups have claimed that the most recent state tax regime is becoming restrictive. The state points to an exploration tax credit and industry documentation of increased spending on the North Slope.

Asked why it didn't sanction exploration drilling this winter, ConocoPhillips told Petroleum News, "We have drilled 20 wells in NPR-A since 2000; this year we will not drill any exploration wells."

Westward expansion roadblock

During those years of high-risk wildcats and exploration wells closer to infrastructure, ConocoPhillips and Anadarko began permitting a fourth Alpine satellite: Alpine West.

In 2005 filings, ConocoPhillips said a CD-6 pad for the Lookout prospect was "marginally economic," but that the Alpine West prospect would support construction of a CD-5 drill pad and, more substantially, a bridge across the Nigliq Channel of the Colville River.

The location of that bridge — ultimately decided through negotiations with Kuukpik, the local Native corporation — led to years of delays. ConocoPhillips hoped to begin CD-5 construction in early 2007, but by early 2010 the company is still awaiting permits.

In recent years, ConocoPhillips replaced its original application with a beefed-up development plan: more wells and larger well pads, larger bridges and more roads.

In the summer of 2009, the company proposed expanding the Colville River unit by 16,400 acres to include the proposed location of the CD-5 pad on federal lands.

The company also proposed "sequential development" in NPR-A to make smaller discoveries economic — just like the "repeatability" Anadarko touted a decade earlier with Alpine construction under way. These smaller discoveries include CD-6 (or Lookout), CD-7 (or Spark) and a previously unproposed satellite called Fiord West.

In the spring of 2009, ConocoPhillips said it expected to develop Alpine West by late 2012, and develop Lookout and Fiord West sometime after 2014. The state is also betting on those satellites, including their production in revenue forecasts for the coming decade.

As the "gateway" to NPR-A, though, CD-5 must first get resolved.

Unitizing the northeast NPR-A

Unitization was a step in the development of Alpine and its satellites and ConocoPhillips has recently moved to unitize land around its discoveries in NPR-A.

In January 2009, the Bureau of Land Management approved the formation of the Greater Mooses Tooth unit, covering the discoveries ConocoPhillips made in 2001. In September 2009, the BLM expanded Mooses Tooth and approved a nearby Bear Tooth unit.

In proposing Mooses Tooth, ConocoPhillips said it planned to process NPR-A production in Alpine facilities. The company said it doesn't have any plans to expand Alpine facilities and declined to say how long those facilities will remain adequate for the region.

The strategy, though, is clear: to continue slowly advancing westward, managing production profiles of various fields to allow maximizing the use of existing facilities.

Stepping out in other regions

The overall success of this strategy carries implications for other areas in the state.

Should the coastal plain of the Arctic National Wildlife Refuge, or the 1002 area, ever be opened to development, this sort of stepping out might be necessary, especially if the billions of barrels estimated in the region are spread over many small accumulations.

In a more likely example, Anadarko appears to be using a similar approach as it explores for natural gas in the foothills of the Brooks Range.

The company has said it doesn't believe the extensive natural gas resources in that region are lumped together, but rather spread over many smaller accumulations over an area of hundreds of miles, meaning Anadarko will need to strategically bring original and subsequent fields into production.

As for Alpine, its satellites and the northeast NPR-A, even when the oil runs out, the existing infrastructure grid may one day become the basis for a natural gas operation, should a major pipeline from the North Slope to markets in the south ever get built. ■

Two newcomers with two strategies

Pioneer and Eni both sanctioned nearshore projects in the Beaufort Sea, but took different approaches to development

By Eric Lidji
For Petroleum News

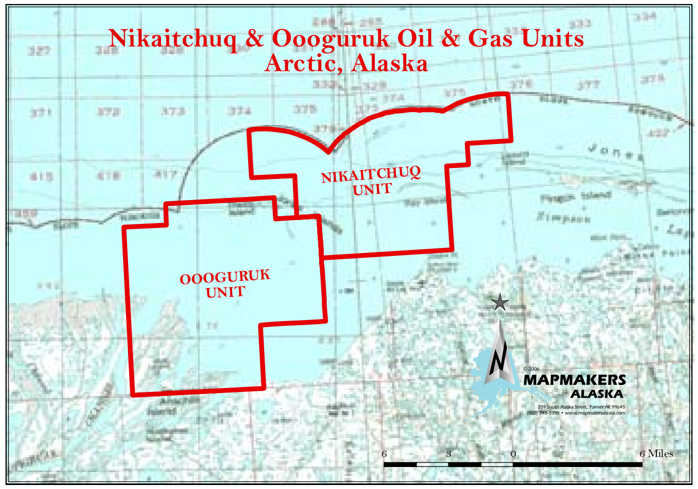
As resource basins mature, and production drops, companies can make smaller plays economic by using existing infrastructure — which has excess capacity as production peaks and drops — to bring down costs. That dynamic is just starting to occur on the North Slope of Alaska, which has only been producing oil for around three decades.

Over the past two years, two companies have progressed on projects to the point where they had to make a decision: Rent or own? Is it more economic to use as much existing infrastructure as possible at the risk of ceding control to another company? Or is it better to spend extra money building duplicative facilities in order to keep more control?

The projects are similar and neighboring.

In June 2008, Pioneer Natural Resources brought the Oooguruk unit into production, making the Texas-based company the first independent to operate an oil field on the North Slope. Just a few miles to the east in the waters of the Beaufort Sea, Italian super-major Eni Petroleum is currently working to bring the Nikaitchuq unit into production.

The history and fate of the projects are slightly intertwined. Both date back to exploration work conducted by Armstrong Oil and Gas in the early years of the decade. Eni is a minority partner in Oooguruk and presumably watched the sharing process firsthand. The plays sit side-by-side in the nearshore state-owned waters of the Beaufort Sea.



The companies took different approaches, though. Pioneer decided to negotiate a deal with ConocoPhillips to rent space at existing processing facilities and pipelines. Eni is currently building its own process facilities and pipelines at Nikaitchuq. Both approaches have presented unique obstacles, and both projects have seen unique successes.

Oooguruk hit the "sweet spot"

Alaska is a bit of an oddball in the Pioneer portfolio.

The company lists its anchor prospects as oil and gas fields

continued on next page

NEWCOMERS *continued from page 27*

in Texas, Colorado and Kansas. Outside of the United States, Pioneer operates in Tunisia and South Africa.

Pioneer came to Alaska in 2002 with the goal of making the North Slope a faster place to operate. The company acquired a 70 percent stake in an offshore oil discovery, known at the time as the Northwest Kuparuk prospect, from Denver-based Armstrong Oil and Gas.

Pioneer originally conducted traditional operations in Alaska, a development program backed by an exploration campaign. After several bum winters, though, the company limited its focus in 2007 to developing a few plays, of which Oooguruk is the largest.

Oooguruk is the most expensive project in Pioneer's portfolio. The project cost around $500 million to bring online, of which Pioneer was on the hook for around $350 million.

Not only did this represent a shift in thinking about the economics of developing a prospect, but also about the day-to-day operations needed to bring a field online.

Before Alaska, Pioneer tended to drill a lot of relatively cheap and predictable wells. Between 1998 and 2000, the company participated in 1,168 wells, 92 percent of which were successful, at a cost of some $867.6 million.

The total cost to bring Oooguruk into production exceeded what the company typically spent at the time in a given year to explore and develop all of its prospects around the world.

Oooguruk also required overcoming many logistical hurdles, first among those the location. To tap the offshore reservoir, the company chose to build a six-acre gravel island in shallow water and tie it back to land with a 12-inch underwater pipeline.

The logistics of running an island posed challenges Pioneer didn't face anywhere else in the world. For instance, to simply keep the island stocked with people and supplies, Pioneer needed three transportation modes: boats in the summer, trucks to cross the ice in winter and helicopters during the ice-filled "shoulder" seasons of spring and fall.

Pioneer saw Oooguruk as being worth the money and effort, though, because of the potential reserves. By October 2007, as construction of Oooguruk neared completion, Pioneer had booked about 900 million barrels of proven oil equivalent reserves companywide and expected the Oooguruk field to contain 70 million barrels of oil.

"For a company like us, it's right in the sweet spot," Timothy Dove, the president and chief operating officer of Pioneer, told Petroleum News about Oooguruk in the fall of 2007.

While Pioneer complained about the shifting tax regime in Alaska — during the years it took Pioneer to bring Oooguruk online, the state went through three fiscal systems — it took advantage of a new exploration incentive that earned it $75 million in early 2008, several months before the company produced any oil-based revenue in Alaska.

Looking for facility access

To get all that Oooguruk oil to market, though, Pioneer needed processing facilities to separate the stream of oil, gas and water coming up from the wells, and pipelines to ship the processed crude to the trans-Alaska oil pipeline more than 50 miles to the east.

The cost to build those facilities is partly what kept previous companies from developing Oooguruk. Even at 70 million barrels, the remoteness and expense of a nearshore prospect in northern Alaska made the project uneconomic as a standalone venture.

Those costs could be reduced or eliminated by piggybacking on existing infrastructure, renting capacity from nearby pipelines and processing facilities already in operation.

For Pioneer, the closest facilities sat onshore at the Kuparuk River unit. That meant the independent needed to strike a deal with ConocoPhillips, operator of Kuparuk.

State and industry officials anticipated this problem as early as 1999, with the release of the Charter for the Development of the North Slope. The document came after industry wide mergers and acquisitions at the end of the century shook up field ownership, prompting concern among state officials about issues such as access to existing facilities.

The charter contained a section devoted to facility access. In it, the state claimed the authority to require facility owners to let third parties have access to existing infrastructure.

The producers didn't comment on the state's claim, but also said they would not "unreasonably withhold their voting support as facilities owners for allowing nearby satellites to have access to existing unit facilities on reasonable commercial terms."

In other words, they agreed to be cooperative.

Landmark report

The general agreement still left the problem of nagging details, though, and so in May 2004 the state released a landmark report on facility sharing across the North Slope.

The report inventoried the existing infrastructure, measured the current capacity of each unit, and looked ahead to what capacity might be in the future, as the profile of existing fields changed. It also listed the concerns that could prevent sharing on the North Slope.

At the time of the report, Kuparuk presented some immediate capacity challenges. The 23-year-old field no longer produced oil at full capacity for the processing facilities, leaving some space for Pioneer to rent, but the facilities remained at "capacity limits" for water, total liquids and natural gas — and capacity in the Kuparuk pipeline was "nearly full."

The liquids capacity problem is not uncommon, and can be solved by "back out," where a third party compensates a facility owner for oil or gas not produced as a way to free up capacity. Facility owners take less productive wells offline, allowing room for processing oil from a newer field where wells are producing less water, and are compensated for backing those wells out of production.

The 2004 report also noted that several standard agreements already existed at Kuparuk, setting out rough guidelines for how third parties could process oil, gas and water at the Kuparuk facilities, and also get supplies of injection water, electricity and other needs.

These "ballots" formed the basis of an early facilities sharing agreement between Winstar Petroleum, a small independent, and the Kuparuk River unit. While that agreement was finalized, it was never put into use because Winstar never sanctioned production.

The challenges of sharing

Once Pioneer sanctioned Oooguruk it became the first company in Alaska to try to negotiate a facility sharing agreement that would eventually be put to use.

Pioneer decided to negotiate a deal with ConocoPhillips to rent space at existing processing facilities and pipelines. Eni is currently building its own process facilities and pipelines at Nikaitchuq. Both approaches have presented unique obstacles, and both projects have seen unique successes.

Pioneer and ConocoPhillips reached an "agreement in principle" as early as the fall of 2006, but claimed that the state deliberations over the production tax system forced them to reconsider the terms of the agreement in the fall of 2007. The companies finally announced a deal in March 2008, with first oil at Oooguruk less than six months away.

Under the agreement, oil from Oooguruk would flow through a gathering line to Kuparuk River unit drill site 3H, then on to a Kuparuk River unit processing facility. From there, it would go to Pump Station 1 and the start of the trans-Alaska oil pipeline.

Almost immediately, the challenges of sharing facilities became public.

Pioneer shut down production within weeks of bringing Oooguruk online because of planned maintenance at Kuparuk facilities. In March 2009, Pioneer shut down production again because maintenance cut the company off from the water supply it used for injection.

In both cases, the company called production losses "insignificant."

Another problem came in the form of tax payments.

continued on next page

JUDY PATRICK

At left, photo taken at an Oooguruk exploration drill site in 2003. Using their titles in 2003, standing in front of Nabors Alaska Rig 27E, from left to right, are Waska Williams, jr., North Slope Borough planning field officer out of Barrow; Gordon Brower, North Slope Borough planning department; Gordon Matumeak, Kaktovik, North Slope Borough field inspection, also on board of Kuukpik Subsistence Oversight Panel; Stu Gustafson, Armstrong Oil & Gas; Bill VanDyke, state petroleum manager, Alaska Division of Oil and Gas; Rusty Cooper, Pioneer Natural Resources drilling manager; Chris Ruff, petroleum land manager, Alaska Division of Oil and Gas. Oooguruk, which went into production in 2008, is the first independent-operated oil field on Alaska's North Slope.

NEWCOMERS *continued from page 29*

With the sharing arrangement, the state began measuring Kuparuk production levels by subtracting Oooguruk production amounts from the combined production from both fields, making the larger field dependent on accurate measurements at the smaller field.

Pioneer also began looking for solutions.

First, the company got state officials to approve a new metering system. For the first time, the Alaska Oil and Gas Conservation Commission approved the use of multiphase flow meters. These meters allow producers to measure oil, gas and water rates coming from a well without having to separate the three-phase stream into its individual parts.

Multiphase flow meters use nuclear detectors and are expensive, but ultimately pay off because they require less space and maintenance than traditional gravity separators.

Second, Pioneer plans this year to look for an independent source of water to supply Oooguruk injection wells to keep from having to be dependent on ConocoPhillips.

Why it was worth the work

The hassle appears to have been worth it for Pioneer.

When it picked up the prospect and decided to develop it, Pioneer estimated the reserve potential at Oooguruk to be between 70 million and 90 million barrels of oil equivalent. That oil sat in two main pools, the Kuparuk pool and the deeper and larger Nuiqsut pool.

Once Pioneer began drilling, though, it increased that estimate. In February 2009, Pioneer announced that the recoverable reserves at Oooguruk could be as much as 40 percent more than expected: between 120 million and 150 million boe. On top of that, the company said it had only booked 10 million barrels of oil from its Alaska operations.

In addition to the increased resource potential, Pioneer announced that Oooguruk was performing better than expected in the short run. The initial wells at Oooguruk produced at

7,000 barrels per day, compared to the 5,000 bpd the company originally estimated.

This production gave Pioneer a revenue stream as oil prices tanked at the end of 2008, and when the company began scaling back its global operations, it spared Oooguruk.

In late 2008 and early 2009, as oil prices fell more than $100 per barrel, Pioneer cut back from 29 rigs to three rigs across its portfolio, and said it wouldn't resume normal drilling until prices hit $60 per barrel for oil and $6 per thousand cubic feet for natural gas.

Those cuts included postponing plans to drill an appraisal well at the Cosmopolitan unit in the Cook Inlet basin of Southcentral Alaska, but the cuts did not include Oooguruk.

Speaking in Anchorage in January 2009, Jay Still, executive vice president of domestic operations for Pioneer, said Oooguruk made the cut because it came online in June, before markets crashed, because Arctic projects are more difficult to stop and start up again quickly, and because Pioneer at the time favored oil investments to gas projects.

A new approach to development

With Oooguruk development moving ahead as planned, Pioneer announced a new approach to developing the field in June 2009, a year after bringing the field into production.

Pioneer planned to drill horizontal lateral wells in the second and third quarters of 2009 to fracture and stimulate the Nuiqsut formation, the deeper of the two Oooguruk pools.

By November, Pioneer said Oooguruk production was averaging 6,000 bpd, and said it expected production to increase 10 percent between the fourth quarter of 2009 and the fourth quarter of 2010, according to Scott Sheffield, chairman and chief executive officer.

Sheffield said Pioneer wants to expand Oooguruk vertically by developing shallower oil deposits and horizontally by reaching out farther from the island. Pioneer expects to drill extended reach wells that go out about 18,000 feet to a depth of about 8,000 feet.

Eni decides to build instead

Just to the east, Eni Petroleum is taking a different approach to nearshore development.

Eni came to Alaska in August 2005, purchasing North Slope holdings from Armstrong Oil and Gas. Those included both onshore and offshore prospects, and for nearly two years the Italian company pursued both avenues. In 2007, though, Eni shifted from exploration to development, focusing its time and resources on the Nikaitchuq prospect.

Eni already owned a minority share of the offshore field, and picked up the remaining 70 percent from independent Kerr-McGee in April 2007, giving Eni complete ownership.

The differences between Eni and Pioneer, its partner at Oooguruk, are important.

Pioneer is among the largest independents in the country, but still a small company by oil industry standards. Eni, on the other hand, is one of the biggest companies in the world.

In 2008, Eni produced around 1.8 million barrels of oil equivalent every day from projects on six continents, earning the company some $12.6 billion (8.83 billion euro).

Eni operates fields in Norway, giving it some Arctic experience, enough to make the company cautious about how it approached Nikaitchuq. The moves Eni made in 2007 and 2008

continued on next page

NEWCOMERS *continued from page 31*

suggest the company saw the offshore venture as being an inherently risky one.

Kerr-McGee saw it that way as well. The company asked the state to expand the Nikaitchuq unit to include the neighboring Tuvaaq unit, nearly doubling the size of the prospect, and also asked for royalty modification during periods of lower oil prices.

Kerr-McGee failed to convince the state on both accounts, but Eni succeeded.

The expanded Nikaitchuq protected more of the resource by unitization. Eni estimated that Nikaitchuq contained 180 million barrels of recoverable reserves from two formations, including one with heavier, and therefore more expensive, oil. The royalty modification protected Eni through the long timeline for developing a project in Alaska.

Under the agreement, the royalty rate on oil produced from several leases rises and falls on a sliding scale connected to the delivered price of Alaska North Slope crude oil.

Up to an inflation-adjusted price of $42.54 per barrel, Eni pays 5 percent royalties to the state. As oil prices increase, so does the royalty rate, topping out at 16.667 percent, the original royalty rate attached to most leases in the unit. The scale is based on a Minerals Management Service program for deepwater federal leases in the Gulf of Mexico.

Those two requests suggest Eni felt the resource at Nikaitchuq wasn't large enough to justify development, and that, even with the expanded unit, the resource wouldn't be profitable without some financial incentives should the price of oil fall after production began.

This might be because Eni is building its own production facilities at Nikaitchuq, rather than following Pioneer's lead and renting space at existing facilities. While expensive, those facilities will give Eni more freedom at Nikaitchuq than Pioneer has at Oooguruk.

The move is unprecedented. Once completed, Eni's facilities will be the first on the North Slope not operated by the major leaseholders BP, ConocoPhillips and Exxon Mobil.

A quick start, then delays

In January 2008, Eni sanctioned a $1.45 billion development plan for Nikaitchuq.

Eni decided to take a dual approach to developing the field, drilling both from an artificial island built in the Beaufort Sea, and from an onshore pad at Oliktok Point.

The plans included a 3.8-mile subsea pipeline connecting the island to a processing facility at Oliktok Point capable of treating as much as 40,000 barrels of fluid per day, and a 14-mile pipeline connecting that facility to the ConocoPhillips-owned Kuparuk network, which would in turn deliver the fluids to the trans-Alaska oil pipeline.

Even though independent processing facilities promised more control, the decision to build rather than rent forced Eni to deal with its own unique set of challenges.

In early 2009, Division of Oil and Gas Director Kevin Banks told Petroleum News that Eni planned to put the brakes on Nikaitchuq, slowing development from the "fast track" to a "normal pace," which would delay startup of the oil field by six months to a year.

Although Eni made no public statement, rumors around the oil patch suggested that the company got nervous because of low oil prices and the weak economy at that time.

Those claims didn't entirely hold up, though. The royalty modification protected Eni during stretches of lower oil prices. As for the weak economy, the well-capitalized mega-major did not need to rely on tight credit markets to move ahead on spending plans.

In addition, Eni wasn't going on a companywide cost cutting spree.

The company ultimately asked for more time to develop Nikaitchuq. The state approved the request, but noted in its ruling that Eni decided to delay development not only because of the weak economy and the drop in oil prices, but also because the company missed the window to barge "processing and operations modules" to the North Slope.

Eni was building those facilities in Louisiana, not Alaska, and according to the state, Hurricane Ike caused a "work stoppage" at the Louisiana fabrication yard where the construction was taking place. Because of the seasonal restrictions, companies have a brief window each summer to sealift material to the North Slope.

"A variety of factors, including but not limited to schedule delays, not meeting sealift deadlines, capital constraints and fabrication delays have caused Eni to change the pace of development for the Nikaitchuq unit from an accelerated pace of development to a more normal pace," the company said in a plan of development filed in July 2009.

Even with those delays, though, Nikaitchuq is moving at a quick pace for Alaska.

Eni has already built several gravel pads, a subsea pipeline connecting the offshore and onshore facilities and part of an overland pipe to feed Nikaitchuq oil into the Kuparuk pipeline. Eni also drilled its first production well, which now only awaits facilities.

As a result, Eni now expects to start producing oil from Nikaitchuq by the end of 2010. ■

The non-legal risks at Point Thomson

The fighting between the state and the industry over Point Thomson comes down to a challenging and barely understood reservoir

By Eric Lidji
For Petroleum News

ExxonMobil's Point Thompson field 2009.

EXXONMOBIL

In coffee shops and op-eds in Alaska, discussion of Point Thomson tends to focus on legal issues: Will the state revoke leases? Will it terminate the unit? Will the companies sue?

Underlying those legal issues, though, are geologic and engineering uncertainties that set off the 30-year dispute between government and industry over the North Slope field.

Now, with ExxonMobil and its partners drilling at Point Thomson for the first time since the early 1980s, those uncertainties are moving to the forefront of the discussion. The drilling program under way is a small-scale effort designed not only to produce hydrocarbons from the eastern North Slope field, but also to answer questions about the geology of the region and the best way to develop the complex resources buried there.

Those answers will determine what risks are and are not acceptable at Point Thomson.

Seven years of exploration

Exxon discovered Point Thomson in the mid-1970s, as construction wrapped up on the trans-Alaska oil pipeline and the North Slope moved toward becoming a producing basin.

Although Exxon drilled numerous wells over the next decade at Point Thomson, much of the information gleaned from those wells remains proprietary, and therefore public knowledge about the region is even scarcer than already limited private knowledge.

The leases at Point Thomson date back to 1965, before the discovery of Prudhoe Bay to the west. Exxon found oil and gas with the Alaska State A-1 well in 1975, and found the oil and gas in the Thomson Sands with the Point Thomson Unit No. 1 well in 1977.

The company performed two flow tests with the PTU No. 1 well, finding a deposit of condensate and a deeper deposit of heavier oil. In delineating those prospects over the following seven years, the company found two more reservoirs at Point Thomson.

Those wells confirmed the existence of a large, high-pressure, gas-condensate pool with a viscous oil rim in a reservoir consisting primarily of the Beaufortian-age Thomson Sandstone; a separate, shallower oil pool exists in younger Brookian sands.

The Point Thomson reservoir — a mix of oil, natural gas and condensate — discovered in 1977 remains to this day the largest proven, but undeveloped field in Alaska. The Alaska Department of Natural Resources currently believes the unit holds some 300 million barrels of liquids and 8 trillion to 9 trillion cubic feet of recoverable natural gas.

While 17 wells were drilled within the boundaries of the Point Thomson unit between 1975 and 1996, none have been drilled into the Point Thomson reservoir since the early 1980s.

A complicated legal battle

That absence of drilling is the basis of a complicated legal battle that began in 2005 and continues on in varying degrees, even as Exxon is currently drilling at Point Thomson.

Between 1977 and 2005, Exxon proposed and the state approved 21 plans of development for Point Thomson that never ultimately resulted in production from the unit.

In 2001, the state agreed to expand the unit if Exxon and the other leaseholders committed to a seven-well drilling timeline, or agreed to pay penalties if they didn't drill.

At the time, the state wanted Exxon to produce the oil and condensate resources at Point Thomson first, cycling the natural gas through the reservoir to maintain field pressures.

Until 2004, Exxon and its partners agreed, submitting development plans that called for producing the liquids before moving on to the extensive natural gas resources.

Exxon ultimately failed to drill any of the wells outlined in 2001, but paid several fines.

In 2004, Exxon and its partners submitted a plan of development that favored producing the natural gas resources first, saying that gas cycling was economically risky. Because of the lack of a gas pipeline on the North Slope, though, that meant stalling production.

The Alaska Oil and Gas Conservation Commission classified Point Thomson as an oil field, meaning the commission would need to approve any gas off-takes in advance.

In June 2005, Exxon submitted a 22nd Plan of Development for Point Thomson that also called for developing the natural gas first rather than cycling it for liquids production.

Over the course of several years, the state ultimately rejected that plan, then put the unit in default, then terminated the unit and finally took back all of the leases. Those events in turn prompted appeals and lawsuits from Exxon and the other Point Thomson owners.

In February 2008, Exxon submitted a 23rd Plan of Development, calling for a small-scale gas cycling project of 10,000 barrels of liquids per day, a compromise from the gas-first approach Exxon wanted, but less than the 40,000-60,000 bpd it had once proposed.

continued on next page

POINT THOMSON *continued from page 35*

Point Thomson a rare bird

The debate over the economics of Point Thomson is rooted in the uniqueness of its reservoir, a petroleum system known as a "retrograde condensate reservoir."

These reservoirs are typically deeper, hotter and under higher pressure than traditional reservoirs, creating challenges where companies try to develop the resources.

In a conventional oil field, oil and gas are mixed together in the reservoir. When a drill bit enters the reservoir and underground pressure begins to fall, the oil and gas separate.

In a May 2007 white paper on Point Thomson, the Alaska Oil and Gas Conservation Commission compared this to a bottle of soda. When closed, the bottle appears to contain only liquid, but when opened, a gas separates from the liquid and rises to the surface.

In a conventional gas field, the gas contains a bit of vaporized hydrocarbon liquid called condensate. As the gas is extracted, the lower temperatures at the surface — compared to the warmer temperatures underground — turn this vaporized condensate into a liquid. The AOGCC compared this to the fog created when someone breathes on a cold window.

These tendencies, though, don't apply to a retrograde condensate reservoir.

In fields like Point Thomson, a drop in reservoir pressure doesn't cause the gas to separate from the oil, and condensate doesn't stay vaporized. Instead, the vapor turns to a liquid underground and clogs up the pores that allow oil and gas to pass to the surface.

BP EXPLORATION (ALASKA) INC.

Different ways to develop

As a result, there are several strategies for developing these reservoirs.

The first is a conventional approach, where the natural gas is extracted. This is called "blowdown." At first, the natural gas brings up a large amount of condensate, but at the same time, condensate still underground becomes a liquid and clogs up the pores.

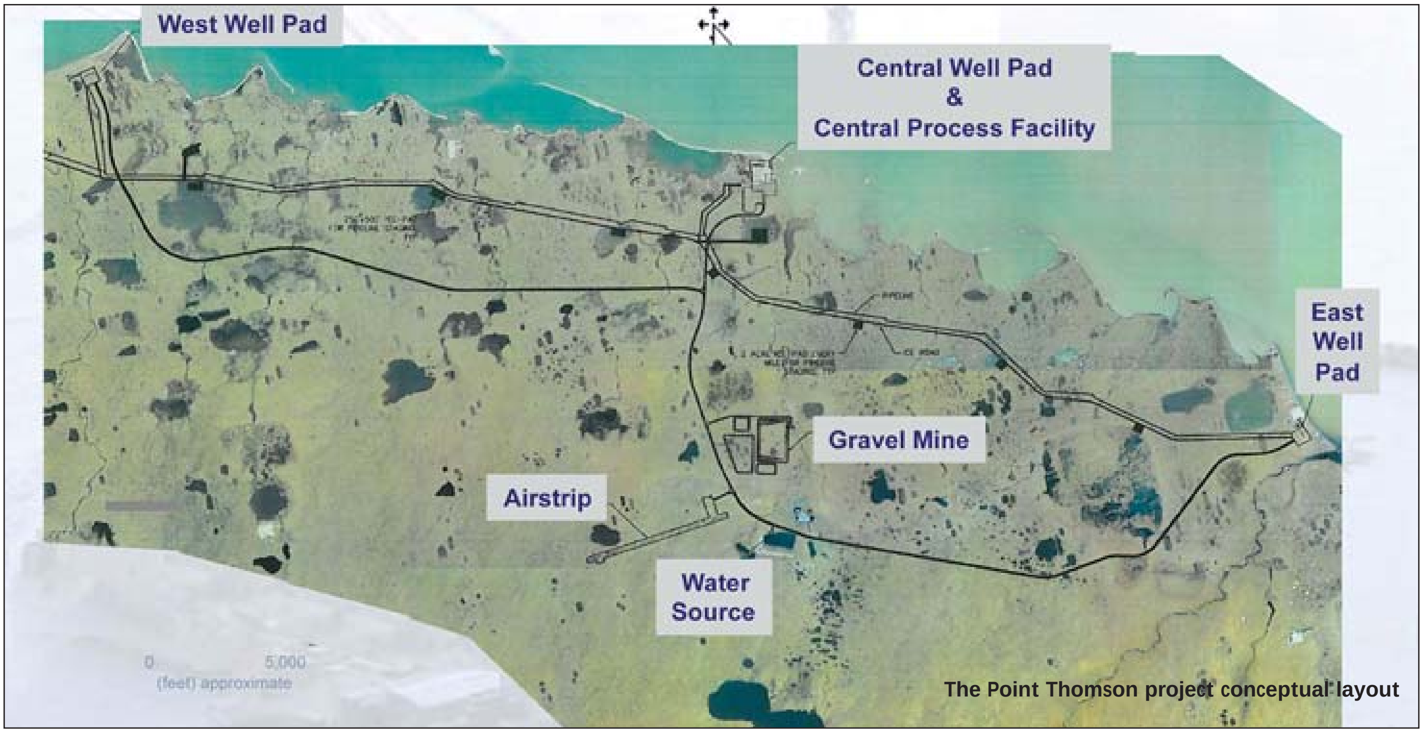
According to the AOGCC, this not only prevents that condensate from ever being produced, but also limits future gas production by essentially locking up the reservoir.

A second approach is called "gas cycling," where natural gas is extracted from the field, stripped of its condensate and re-injected to maintain the high pressure in the reservoir.

This approach yields a much higher recovery of hydrocarbons than blowdown, but it is also more expensive because it requires building specialized recycling equipment. In addition to the extra construction costs, gas cycling also strains the cash flow of the development effort by delaying the first gas sales until all of the condensate is produced.

A third approach involves replacing the injected natural gas with an outside substance — like nitrogen or carbon dioxide — to maintain pressure without stranding the natural gas.

While this approach yields the highest recovery and the greatest cash flow, it also costs the most, because in addition to expensive recycling equipment, the operator must not only buy a large amount of nitrogen or carbon dioxide, but also get it to



The Point Thomson project conceptual layout

the drill site.

Each of these scenarios requires an economic trade-off, forcing an operator to decide whether the additional resource is worth the cost of production, or should be sacrificed.

In most cases, the decision is final, and can't be undone.

Better to cycle or produce?

The debate over Point Thomson is about which of these approaches to take.

In June 2008 PetroTel Inc. released a state-commissioned study of the Point Thomson region and determined that gas cycling would maximize the recovery of the reservoir.

PetroTel estimated the original gas in place at Point Thomson at somewhere between 8.5 trillion and 10.4 trillion cubic feet, with associated condensate of 490 million to 600 million barrels, and a potential oil rim of 580 million to 950 million barrels.

By cycling natural gas for 20 years, Point Thomson could yield 620 million to 850 million barrels of liquids — oil and condensate — and then go on to yield 4.8 trillion to 5.9 trillion cubic feet of natural gas, PetroTel concluded. By comparison, the firm estimated that through blowdown, Point Thomson would produce some 210 million to 305 million barrels of liquids and between 6 trillion and 7 trillion cubic feet of gas.

"This incremental recovery of oil is larger than the expected ultimate recovery from the Alpine Oil Field," the state Division of Oil and Gas noted in a summary of the report.

At a June 17, 2008, legislative hearing, Point Thomson leaseholders challenged that conclusion.

Representatives from ExxonMobil and Chevron told lawmakers that Point Thomson oil reserves didn't equal anoth-

continued on next page

POINT THOMSON *continued from page 37*

er Alpine, and that the estimates of how much oil would be lost if the companies produced the gas resources first was based on false assumptions about how much oil could be recovered from the field under any development scenario.

The companies said gas, and not liquids, were the primary resource at Point Thomson.

Craig Haymes, then ExxonMobil Alaska production manager, said the PetroTel report seemed to be based on limited, selective and, in light of the fact that litigation had kept the state and the companies from sharing data for three years, less than timely information.

"The report provides an estimate of recoverable liquids and gas, but it does not consider that fundamental necessary technical work that has yet to be done," Haymes said.

As an example, Haymes pointed to the oil rim. PetroTel estimated a recovery factor of up to 50 percent from the oil rim, Haymes said, but "the oil rim is thin, discontinuous and heavy oil — molasses."

PetroTel assumed horizontal wells would be used to develop the reservoir. "We're not aware of anywhere in the world that anybody has drilled horizontal wells in this pressure reservoir with this deviation. And we did research last week to confirm that," he said.

More to the point, though, the companies said the gas at Point Thomson was absolutely necessary to justify the construction of the natural gas pipeline from the North Slope.

Under the PetroTel model, the natural gas at Point Thomson would be tied up for 20 years after the start of condensate production. Under the most optimistic timetables for a natural gas pipeline, Point Thomson gas wouldn't be available for a decade or more.

The companies said Point Thomson gas represented a quarter of the known reserves on the North Slope. The state said existing reserves at Prudhoe Bay and Kuparuk could be used until Point Thomson became available as a gas field. The companies said that blowing down Prudhoe Bay and Kuparuk posed the same problem of lost oil recovery.

Is PTU a Tarn or a Badami?

The 23rd Plan of Development involves a gas cycling program to test whether the technique will work at Point Thomson, but Haymes said cycling was inherently risky.

No one knows for sure whether the cycling production and injection wells will "communicate." If not, pumping gas back into the ground won't maintain field pressure.

Haymes said the geology remains largely unknown at Point Thomson. For example, he said, the location of the field running from onshore to offshore means that the permafrost in the area has changing thickness, making seismic data more challenging to interpret.

Also, the Brookian sequence at Point Thomson comes with an uncertain legacy. The sequence is found at the successful Tarn and Meltwater fields in the Kuparuk River unit, but also at Badami, the notoriously finicky field just west of Point Thomson.

One of the features of the Brookian is turbidites, or layers of sand and silt. In Badami, these layers form "sand lobes" that cut off one reservoir from another. For the past decade, BP, the operator of Badami, has struggled to find a way to develop the field.

If Point Thomson resembles Badami, it could complicate production. However, if Point Thomson resembles Tarn and Meltwater, it could become a significant oil producer.

Much technology and much cash

Either way, Point Thomson is expensive.

In March 2008, Haymes said Exxon and its partners had spent more than $800 million on Point Thomson, without a single producing well or dollar of revenue to show for it.

The 23rd Plan of Development currently in effect is a $1.3 billion gas cycling program to drill five wells at Point Thomson and produce 10,000 barrels per day by the end of 2014.

Exxon and its partners have presented the program as a major technological undertaking.

In a March 2008 administrative hearing, Bill Meeks, ExxonMobil drilling engineering manager, said the pressure of Point Thomson gas was 10,200 pounds per square inch, requiring drilling mud twice as dense as what is used on traditional North Slope wells.

The need for wells to pass at an angle through the reservoir will require additional mud pressure to keep rocks from caving around the well, and therefore those initial Point Thomson wells will test the limits of the technology used to drill difficult wells. "That's one of the big risks we have at Point Thomson," Meeks said. "How far can you go?"

The wellhead structures at Point Thomson are rated to 15,000 pounds per square inch, about three times the rating of a typical Prudhoe Bay wellhead. The water-oil-gas separator in the processing facilities will be rated to 3,000 pounds per square inch, requiring six-inch steel walls, with compressors rated to 20,000 pounds per square inch.

The mechanical requirements for drilling in this challenging reservoir — like upgrades to Nabors Rig 27-E — combined with the already increased costs of drilling in an isolated corner of the already isolated North Slope basin, means that Point Thomson wells will cost 10 to 15 times as much as a typical Prudhoe Bay well, according to Haymes.

Exxon cites these details to justify its small-scale production at Point Thomson, saying that a smaller program will test the technology, provide information about the reservoir and allow the company to change gears if gas cycling turns out not to be appropriate.

Or, if gas cycling works as hoped, the small-scale effort can be ramped up. Exxon plans to tie Point Thomson back to infrastructure at Badami with an 80,000-barrel-per-day pipeline, capable of handling the production levels of the original gas cycling program.

Bigger rewards within reach?

Despite ongoing legal issues, Exxon is drilling its first wells at Point Thomson under the new plan of development. The company began in winter 2009 and continued this winter.

The potential rewards of the program are huge. Under the various opinions about the field, Point Thomson could bolster the existing oil pipeline, justify construction of a gas pipeline or become a regional hub for development of the eastern North Slope.

With existing facilities, Point Thomson could even possibly be used to tap oil from the coastal plain of the Arctic National Wildlife Refuge, also known as the 1002 area, without having to touch the surface of the often-debated federal plot to the east of Point Thomson.

And as always with Point Thomson, interesting clues remain.

In June 2009, Exxon announced that it would partner with TransCanada on a state-sponsored natural gas pipeline from the North Slope to southern markets, and the plan those companies submitted to the state includes a gas pipeline from Point Thomson. ■


160H

Don't repeat the mistakes of others

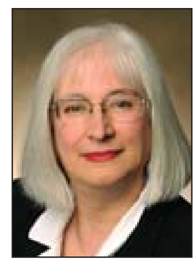
Petroleum News Publisher Kay Cashman advises newcomers to 'save time and money' by utilizing Alaska experience

By Kay Cashman

Publisher & executive editor of Petroleum News

There is a reason the Alaska subsidiaries of Denver-based Armstrong Oil and Gas use contractors with Alaska experience in their North Slope and Cook Inlet operations.

One of the most successful independents to work in the northernmost state, Armstrong didn't pick-up a single lease until he had put together a team with Alaska geological, land, permitting and engineering experience.



As an editor at Petroleum News, as well as its publisher, I have seen oil and gas companies come and go. Sometimes it's the luck of the geology, but a common theme in many failures is that the oil company brings in people with little or no Alaska experience in an attempt to 'save money' and show that the job can be done better and for less. In the end, they land up spending more money and, too often, leaving the state a good deal poorer than they arrived.

Some companies learn their lesson early, hire experienced contractors, stay, and do well.

Alaska IS different

But most insist Alaska is no different than anywhere else, especially the Cook Inlet basin, which is south of the Arctic Circle.

That's not true, not in any sense.

Discounting the value of local knowledge and contacts and the state's unique logistics, the political and permitting environment alone is far more complicated and certainly stricter than any other state in the union. The only country that compares with Alaska in terms of strictness of environmental regulations is Norway. What takes a day in other petroleum regions can take months here.

Local permitting agents have the expertise to get a project permitting in a timely fashion.

Local contractors, which include outside contractors that have worked in Alaska for a long time, have grown their businesses here through the development of innovative technology and involvement in groundbreaking projects. They have mastered the logistics of working in a nearly road-less wilderness.

There is lots of oil and gas to be found in this state.

So be smart about it: save time and money by hiring contractors and suppliers with lots of Alaska experience. ■

Alaska: Big Risk, Bigger Rewards

A view from the perspective of a consultant

By Arlen Ehm
Geological consultant

I firmly believe that any company can operate in Alaska, and I will tell you why I believe this to be true.

I have been involved in Alaska exploration for 44 years beginning with the first well drilled from the first platform in Cook Inlet in 1965. I have worked for entities of all sizes in nearly all of the basins in Alaska. I have been around Alaska for quite a while and have probably worked with the fathers and grandfathers of current professionals in Alaska.

Arlen Ehm, Geological Consultant

I hold both bachelor's and master's degrees in geology from Wichita State University. After nine years of employment as a geologist I became a consultant and for the past 33 years have been an Anchorage-based geological consultant. I have provided consulting services to various state government agencies and to various federal agencies including the Internal Revenue Service, the Federal Trade Commission, the Federal Bureau of Investigation and the Securities and Exchange Commission. Consulting services have been provided to more than 80 clients both domestic and foreign.

I have also evaluated more than 20 oil and gas properties and I have served as an expert witness in seven court cases including one where I served as a special master to the Superior Court of the State of Alaska.

In addition to my sole proprietorship, I am a co-founder and a principle of Alaska Research Associates Inc. ARA prepared basin analyses of some of the major basins in Alaska including an extensive field investigation in ANWR in 1984. I was the vice president-Alaska for a small Lower-48 independent, and I later provided geological and management services to another small independent that entered the Alaska exploratory scene.

I have been involved in many aspects of exploration other than geology, although not always by choice. I simply performed as per the requirements of each project and each client. However, that exposure allowed me to develop experience in areas far afield from simple geology.

In my role as a consultant, I am constantly in contact with independents and mid-sized companies in the Lower-48 who wish to review the prospectiveness of the Alaska exploratory

continued on next page

EHM *continued from page 43*

scene. I would estimate that I have communicated with at least 25 such companies and I have encouraged them to come to Alaska.

I am presently the project manager for a firm that has an agreement with NANA Regional Corp. for the evaluation of the oil and gas potential of NANA's lands in Northwest Alaska. NANA holds the mineral rights on a large block of acreage and owns seismic, gravity and magnetic data that have been collected within its lands. Evaluation of these data has revealed drillable prospects of considerable size. The potential exhibited by these analyses was sufficient to convince this small company to proceed with the evaluation.

Risks are naturally inherent in a project that is both remote and without oil and gas infrastructure. In order to lower these risks, efforts must begin early on to adequately plan and coordinate all aspects of the operation. By so doing, the risks are reduced and the rewards-to-risks ratio is elevated.

There are many concerns of those companies looking to come to Alaska and become involved, but it should be noted that space does not permit all of them to be addressed here.

The most commonly given concerns are:

- High entry costs
- High operating costs
- High risk
- Permitting problems
- Excessive bureaucracy
- Excessive environmental constraints
- Long lead time
- Remote exploration targets
- Seasonal operational restrictions
- Lack of infrastructure
- Seasonal access

While many of these are common with operations in the Lower-48, several are unique to Alaska or are exacerbated by Alaska conditions. It should be noted that becoming involved in Alaska exploration might not be the correct move for a lot of companies. High potential alone is insufficient cause for such a decision.

It is my determination that any operator can come to Alaska and enter into the oil and gas drilling business. However, it must plan efficiently and far in advance.

When I started to work on the present project, I advised the client that the primary concerns were not going to be the 11 concerns given above as these can all be ameliorated by proper planning. In this project, the primary concerns were going to be logistics, mobilization and demobilization, efficient scheduling and excessive standby charges. However, as stated above, adequate planning and efficient use of the lead time can reduce the cost of the operations considerably. Contingency plans are an absolute must.

For most other areas of Alaska, logistics, mobing and demobing and standby charges will not be as high as in this project. This is true even for North Slope operations since excessive standby costs can be diminished or even eliminated due to the needs of nearby operators for the equipment and because the equipment can be brought back down the Haul Road to Anchorage, both of which reduce the standby costs.

I was 68 years old before I attempted to obtain permits for either geophysical surveys or the drilling of oil and gas wells. I learned the system quickly and have been able to obtain permits that, on the surface, have appeared difficult.

It is my determination that any operator can come to Alaska and enter into the oil and gas drilling business. However, it must plan efficiently and far in advance. Failure to plan adequately blunts the picks of more operators than any other single factor. Not being able to negotiate around a sudden road block because of weather conditions, seasonal constraints or unnecessary standby costs can often lead to total operational costs that are double or even triple the amount on the AFE. I have seen such cases and most cases could have been avoided.

Adequate planning will reduce the stress level of the operator and, perhaps, even eliminate the fear factor, totally, that is usually connected with operating in Alaska. This allows for the pursuit and acquisition of the bigger rewards that are present and available in Alaska. ■

Advice on coming to Alaska from Gustafson

Ask the permitting agency before permitting a project; copy strategies that have already been proven successful; work with majors

By Eric Lidji
Petroleum News

Armstrong Alaska, like other companies, initially worried about Alaska, and before they came to the state, they sent 84 questions about it to Stu Gustafson.

JUDY PATRICK

STU GUSTAFSON

Gustafson worked with Exxon from 1979 until the company closed its Alaska exploration office in 1995. After nearly seven years working in Russia, he returned to Alaska in 2001 to help Armstrong through a lease sale and subsequent exploration.

Gustafson believes the permitting agencies in Alaska became more efficient between the 1970s and the 2000s.

In April 2005, he told Petroleum News, "When I first started doing permitting up here for Exxon in the '70s, I would have said that half the problems, the holdups, were the fault of the agencies and half the part of the companies. Today, I'd say 95 percent were the fault of the companies."

Upon returning to Alaska in 2001, he said, "The feeling you get around the regulators has changed. They seem to both feel more empowered and at the same time they know they are subject to accountability with the current Murkowski administration. I don't remember them being so proactive with applicants," Gustafson said.

The 2000s saw the introduction of independents in Alaska.

Over the course of the decade, a group of smaller companies, focused on upstream operations, came to the North Slope to try to commercialize passed-over prospects.

Those efforts culminated, in a sense, with Pioneer Natural Resources bringing the Oooguruk unit into production in June 2008, making the company the first independent operator on the North Slope since the discovery of Prudhoe Bay in 1968.

If the 2000s brought independent exploration to Alaska, then the 2010s promise to be the decade of independent development, or so hopes several independent companies.

Whether those promises materialize depends in some measure on how well those smaller companies, and any other newcomers eyeing Alaska, navigate the layers of jurisdiction and permitting

continued on next page

GUSTAFSON *continued from page 45*

authorities governing resource development in the state. That process can get expensive and time consuming quickly, making life hard for companies that depend on credit or investors because they don't have the deep pockets of majors.

Armstrong's proven record

Even though Armstrong Oil and Gas didn't produce a drop of marketable oil in Alaska in the 2000s, the Denver-based independent is seen as a model locally for how an independent company can operate smoothly in the state.

Over the course of the decade, the company proved up several North Slope prospects, and then enticed other independents to come north, eventually handing over their prospects and using the money to fund new exploration.

Those efforts from the middle of last decade are now bearing fruit.

Pioneer came into Oooguruk through a partnership with Armstrong, delineating and finally sanctioning an expensive development effort to bring the offshore prospect into production. Just to the east, Italian major Eni Petroleum is currently working to bring the offshore Nikaitchuq unit into development, a prospect it picked up in part from Denver-independent Kerr McGee Oil & Gas, who in turn came to work with Armstrong.

What convinced those companies to take a risk on Alaska — where the resources are universally known to be great, but the potential obstacles often seen as being insurmountable — was the speed and efficiency with which Armstrong operated.

Over a three-year period, Armstrong permitted a standalone production facility and four exploration projects with 11 wells on Alaska's North Slope.

Armstrong is now focused on the North Fork prospect, an onshore natural gas play on the Kenai Peninsula. Recently, the company announced a find large enough to convince Enstar Natural Gas to sign a supply contract with the independent.

Faster can become cheaper

In 2005, Gustafson said that for newcomers to Alaska, "it's more important to know who not to talk to than to know who to talk to," he said. "A lot of consultants set themselves up as experts. Talk to more than one. And talk to the lead agencies. … Look at their files and see who generates the least paperwork, the ones that make it look easy."

In 2006, he said companies needed to listen to regulators, and then respond.

"If you want to make the system complicated, you can," Gustafson said, around the time Armstrong sold the last of its major North Slope assets. "There is nowhere that I have found, whether it's Louisiana, or Texas or Russia, that you will find a more receptive regulatory environment to work with.

"You take your questions to the agencies, and they will give you the right answers," he added. "It's when you have (company) people who have the attitude that they have the answers and are going to educate the agencies that you get into trouble."

Gustafson's words hold weight because of Armstrong's record.

Before Armstrong came to Alaska, company officials heard they would need three years to learn to drill their first wildcat well here, according to Gustafson.

"We got our first leases in six months, and we drilled three offshore wells that year, taking on Pioneer (Natural Resources) as a partner," Gustafson said.

Armstrong drilled eight more wells, six offshore and two onshore, over the following two years.

"So, in what was supposed to take us the timeframe to learn how to drill one well, we drilled 11 wells without any … snags in the process at all," Gustafson said.

The end result is savings, Gustafson said in 2004.

"When you find a way to do something smoother, faster and better, it becomes cheaper," he said.

Copying strategies that work

Following Armstrong, Pioneer also promoted faster "cycle times" for development. From the creation of the unit in July 2003 to production this summer, the company brought Oooguruk online in just less than five years, among the fastest timelines of any unit in northern Alaska.

Duplicating strategies, Gustafson said, is another key.

"Why should the regulatory process be re-invented every time? The operations for our offshore wells were pretty much the same, well to well," he said in 2005. "The same is true for other areas onshore. … The only things that generally change are, say, the length of an ice road or subsistence activity might be different and you have to address those things. But in most cases you can essentially re-use an application package that has been permitted before, change the things that are different, including the names and locations, and use it. There is no reason to re-invent the process each time; and why rewrite the whole short story?"

Any independent seeking success in Alaska must work with two colossal institutions, not only the government that owns the land, but also the major oil producers that own the infrastructure, including the trans-Alaska oil pipeline.

In 2002, Gustafson helped Armstrong get on Greater Kuparuk Area Ballot No. 260A with ConocoPhillips, giving Armstrong access to Kuparuk's roads, mobile and nonmobile equipment, emergency and spill response services, waste management infrastructure and camp services.

"I think Phillips and the other owners — BP, Chevron, ExxonMobil and Unocal — should be commended for what they've done with Ballot 260A. It shortens the permitting process and reduces our environmental footprint," Gustafson said at the time.

"The state also wins," he added. "The ballot reduces its administrative work load, avoids duplicative environmental process and facilitates and promotes the open-for-business strategy established by this administration. All of this enhances the evaluation process of the state's resources, maximizes potential revenues while minimizing impacts on the environment and subsistence activities." ■

SECTION 4: Alaska's geology and exploration trends

Mesozoic formations are well exposed at Puale Bay on the Alaska Peninsula. Limestones of the Upper Triassic Kamishak Formation (foreground) and siltstones of the Middle Jurassic Kialagvik Formation (middle distance) both contain rich oil source rocks at immature to oil window thermal maturity levels. (Source: Alaska DNR, August, 2007.)

ALASKA DNR DEPARTMENT OF GEOLOGICAL & GEOPHYSICAL SURVEYS

By **Alan Bailey**
Petroleum News

In 1968 the discovery of the giant Prudhoe Bay field, the first field to be discovered on Alaska's North Slope and among the 20 largest oil fields ever discovered worldwide, triggered a northern Alaska oil industry that now includes 19 producing oil fields, all feeding oil into the trans-Alaska oil pipeline for transportation to the Valdez Marine Terminal 800 miles to the south.

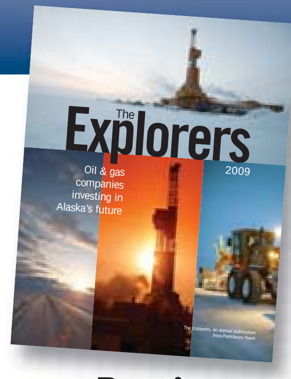
In fact, the totality of northern Alaska consists of five distinct geologic regions: the Brooks Range, the Brooks Range foothills (also known as the Arctic foothills), the North Slope (also known as the Arctic coastal plain), the Beaufort Sea and the Chukchi Sea. The central North Slope and the nearshore area of the Beaufort Sea contain all of the current operational oil fields in northern Alaska. The western North Slope includes part of the National Petroleum Reserve-Alaska.

NPR-A extends from the shoreline south across the western coastal plain and Brooks Range foothills, into the north side of the Brooks Range. The eastern North Slope includes the 1002 area of the Arctic National Wildlife Refuge, the area that has long been the subject of controversy regarding whether it should be opened for oil and gas exploration. ANWR extends south into the Brooks Range, but only the 1002 area is considered prospective for oil and gas.

The Brooks Range consists of east-west-trending mountain groups that reach heights in excess of 6,000 feet. There is little to no oil or gas potential in much of the Brooks Range proper, although rocks exposed at the surface provide valuable insights into many of the petroleum source rocks and reservoir units that occur in the subsurface to the north.

The folded and thrust faulted zone that marks the northern front of the Brooks Range runs generally eastward from the shores of the Chukchi Sea north of Cape Lisburne to a point near the trans-Alaska oil pipeline south of Prudhoe Bay, before turning northeast through the northern part of ANWR.

The Brooks Range foothills between the Brooks Range front and the North Slope consists of a series of rolling hills, mesas and east-west trending ridges with elevations from 900 to 1,500 feet. The rocks exposed in the foothills are younger and less deformed than those in the Brooks Range to the south.



Reprint

This section is a reprint from Petroleum News' annual Explorers magazine, which was written in October 2009.

Continental shelf

The continental shelf of northern Alaska extends north beneath the shallow Beaufort Sea for about 50 miles to a series of geologic faults that mark the edge of the Arctic Ocean continental slope. The geology of the continental shelf forms an extension of the onshore geology of the region — there are two operational oil fields in the Beaufort Sea, the Northstar and Endicott fields, both geologically related to the onshore fields and both connect-

continued on next page

TRENDS *continued from page 49*

ed into the North Slope oil infrastructure.

The Chukchi Sea extends over a vast offshore region, west of the North Slope and Brooks Range foothills. With huge geologic structures that correlate with the hydrocarbon-rich geology on the mainland of northern Alaska, the rocks under the Chukchi Sea contain all of the necessary ingredients for a world-class oil and gas province. Limited exploration in the 1990s yielded a major gas discovery that still awaits development. It's even possible that there's a Prudhoe Bay-scale oil field in the area.

And across this whole vast region of northern Alaska, the petroleum system consists essentially of three major rock sequences: The oldest and generally deepest of the sequences, the Ellesmerian, hosts fields such as Prudhoe Bay, Endicott and Lisburne. The Beaufortian sequence hosts the Kuparuk and Alpine fields. The Brookian, the youngest and generally shallowest sequence, hosts fields such as Badami and Tarn. All of the operational fields are aligned along a major geologic structure called the Barrow arch.

Central North Slope and nearshore Beaufort Sea

WITH MORE THAN 15 BILLION BARRELS of crude oil having flowed down the trans-Alaska pipeline since the startup of the giant Prudhoe Bay field in 1977, and with vast quantities of natural gas recycled into oilfield reservoirs for reservoir pressure maintenance and for possible future export, the central North Slope remains at the fulcrum of the Alaska oil industry. And a cluster of fields, including the Kuparuk River field, one of the largest producing oil fields in North America, has supported an oil infrastructure that spreads out from the original Prudhoe Bay field, an infrastructure that offers the possibility of hooking up modest-sized new discoveries for commercial operation.

Over the last two decades exploration on the North Slope has shifted away from prospecting for fields akin to Prudhoe Bay in size and configuration. This change has resulted not only from the fact that very large oil traps of that type have been virtually exhausted in the onshore and nearshore areas, but also because better seismic data are available now for defining a large number of smaller, subtler traps.

In general terms, people widely recognize the petroleum systems of northern Alaska as hydrocarbon-rich but reservoir-poor. So, with an abundance of excellent source rocks and a relative shortage of reservoir-quality rock formations, any isolated stratigraphic trap, a hydrocarbon trap formed by the juxtaposition of reservoir and seal rocks in the rock strata, stands a good chance of containing oil or gas. Recent exploration has exploited the newfound capabilities of high-end 3-D seismic techniques to find these stratigraphic traps.

Moving west

To the west of Prudhoe Bay the 1994 discovery by ConocoPhillips' predecessor, ARCO, and Anadarko Petroleum of unexpectedly prolific sands at Alpine opened the door to extending a new Beaufortian play beyond the Prudhoe-Kuparuk infrastructure. Perched on the border between state lands and NPR-A, Alpine drove the decision to reopen federal acreage of the west-

continued on page 52

TRENDS *continued from page 50*

ern North Slope to exploration.

A series of wells drilled by ConocoPhillips and Anadarko in the northeastern corner of NPR-A since the renewal of leasing there in 1999 have tested Alpine-equivalent prospects and have yielded discoveries of light oil, condensate and gas in stratigraphic traps overlooked before the advent of 3-D seismic imaging.

In January 2008 ConocoPhillips and Anadarko formed the Mooses Tooth unit, with ConocoPhillips as operator, in a move that protected the companies' NPR-A lease positions in an area by then known to contain five distinct oil discoveries at Lookout, Mooses Tooth, Rendezvous, Spark and Altamura. And in the winter of 2008-09 ConocoPhillips drilled two new wells, the Grandview No. 1 and Pioneer No. 1, in the new unit, as part of a continuing strategy to better understand and eventually develop the Alpine-style play in northeastern NPR-A.

The purchase of new acreage close to Mooses Tooth in the September 2008 NPR-A lease sale, coupled with the relinquishment of more remote NPR-A leases in that same year, confirmed that overall strategy.

In May 2009, having just completed the drilling of the Pioneer No. 1 well, ConocoPhillips announced test results for that well, and for another Greater Mooses Tooth well, the Rendezvous No. 2, drilled in early 2001. The wells tested over a range of 500 barrels per day to 1,300 barrels per day of light oil, and an average natural gas production rate of about 1.5 million cubic feet per day for each well. The company said that it has no immediate plans to further delineate the finds but that it anticipates the accumulations possibly being developed as Alpine satellites.

Then in August 2009, faced with the expiration of dozens of NPR-A leases, ConocoPhillips worked out a deal with the Bureau of Land Management to preserve some leases by expanding the Mooses Tooth unit and forming an adjacent unit called Bear Tooth. The Mooses Tooth unit now stands at 164,014 acres, with a commitment by ConocoPhillips to spud a new exploration well by the third quarter of 2015. The Bear Tooth unit covers 105,655 acres, with a commitment to test an existing well, the Scout No. 1, and drill a new well by June 1, 2012.

Meantime, ConocoPhillips and Anadarko are moving forward with the permitting of their CD-5 Alpine West satellite field, located about halfway between the Mooses Tooth unit and the Alpine field. Alpine West, which will be the first field to go into production in NPR-A, requires the construction of a bridge and pipeline across the Nigliq channel of the Colville River, a construction project in some ways symbolic of the oil and gas industry's movement west into the petroleum reserve.

The development of Alpine West will also represent continued satellite field development associated with the Alpine field, following the earlier development of the Fiord, Nanuq and Qannik Alpine satellites.

Profitable near infrastructure

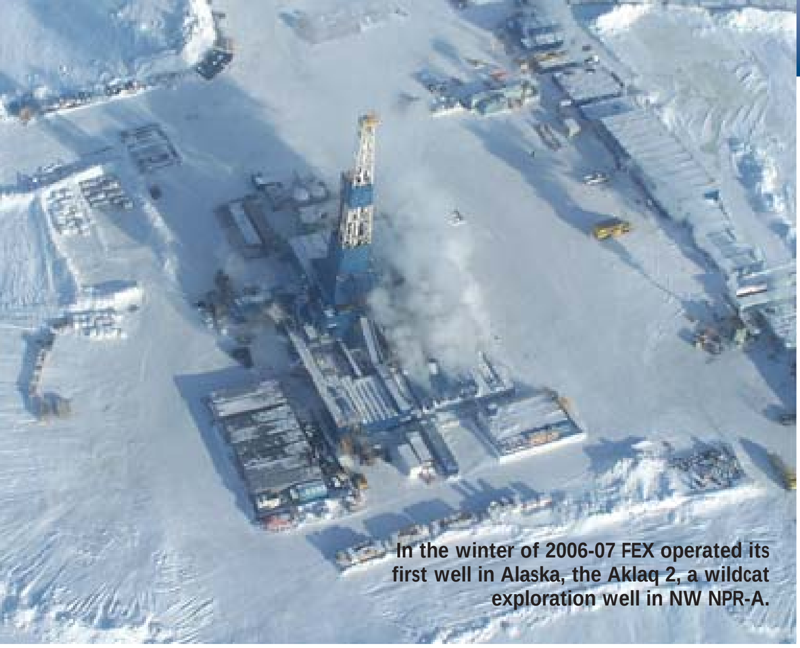
Back near the core area of the central North Slope, the high-performance Beaufortian reservoir of the ConocoPhillips Palm discovery on the western edge of the Kuparuk field led to the construction of a new drill site and expansion of the Kuparuk River unit. This development serves as a reminder of how profitable exploration success close to the existing infrastructure can become, with a cluster of small satellite fields now operated by BP and ConocoPhillips around the major fields of Prudhoe Bay, Kuparuk River and Alpine.

And small independents Brooks Range Petroleum Corp. and Ultrastar Exploration LLC have been pursuing this type of exploration concept in recent years.

BPRC, the operating company for Alaska Venture Capital Group, a private investment group headed by Managing Director Ken Thompson, is leading a joint venture with two other private companies in a multiyear program to explore for light oil close to North Slope infrastructure. BPRC exploration is progressing in the area of Gwydyr Bay, on the Beaufort Sea coast north of the Prudhoe Bay unit.

BRPC drilled the North Shore No. 1 and the Sak River No. 1 wells in that area during the winter of 2006-07. In the following year the company sidetracked and tested North Shore No. 1 at more than 2,000 barrels of oil per day of high quality crude oil from the Ivishak formation. And in August 2009 Alaska's Division of Oil and Gas approved the formation of the Beechey Point unit at North Shore — BRPC wants to fast track development of the find, perhaps using trucks to transfer the North Shore oil to a tie-in with the Kuparuk pipeline, with the development of several

continued on page 54



In the winter of 2006-07 FEX operated its first well in Alaska, the Aklaq 2, a wildcat exploration well in NW NPR-A.

COURTESY FEX

TRENDS *continued from page 52*

small oil accumulations in the area as a future possibility.

In the winter of 2007-08 the BRPC joint venture also drilled the Tofkat No. 1 well east of the village of Nuiqsut, taking 10 oil samples from four different sandstone reservoirs and finding six feet of net pay in the Kuparuk formation, the deepest zone tested.

The joint venture also drilled two sidetracks to find the edge of the Tofkat reservoir, and acquired 210 square miles of 3-D seismic over the prospect, previously called Titania.

Farther east, BRPC wants to do a seismic survey at the Slugger prospect, south of Point Thomson.

Ultrastar consists of another group of private investors, this time under the leadership of Managing Member Jim Weeks. For a number of years Ultrastar and its sister company Winstar have been doggedly trying to drill for small oil accumulations close to infrastructure, with the intent of hooking any viable discovery into existing North Slope production facilities and oil export arrangements.

In 2003 Winstar drilled the Oliktok Point State No. 1 well, which turned out to be a dry hole.

Undeterred, Ultrastar moved ahead with a plan to drill its Dewline Deep prospect north of Prudhoe Bay, testing rocks equivalent to the Prudhoe Bay field reservoir, as well as some secondary targets. Eventually, after a multiyear effort to find a workable combination of drill site and drilling rig, in early 2009 the company drilled the Dewline No. 1 well vertically from an ice pad using the Doyon Arctic Wolf rig, under an arrangement with Rampart Energy, the company which had subcontracted the use of this rig from FEX to drill for gas in the Nenana basin in the summer of 2009.

Ultrastar has remained tight lipped about the Dewline drilling results but appears to be sufficiently encouraged to want to drill a second Dewline well in 2010.

On the southeast side of the Kuparuk River unit, Italian oil major Eni drilled two wells in its Rock Flour unit in the winter of 2006-07, and one well at its Maggiore unit to the south of Rock Flour in that same year. Eni had entered Alaska in 2005 with its purchase of Armstrong Oil and Gas' Alaska interests, following that deal with the 2006 purchase of the state leases that included Rock Flour and Maggiore.

Eni has not announced the results of its North Slope drilling.

On the southwest side of Kuparuk, Pioneer Natural Resources announced in May 2006 that it had found oil in Beaufortian and Brookian horizons in its Cronus No.1 well, but that the reservoir formations were too tight for viable production. Pioneer's Hailstorm No. 1 well, south of Prudhoe Bay, drilled shortly before the Cronus well had proved to be a dry hole.

ConocoPhillips and Pioneer drilled the Antigua No. 1 well south of Prudhoe Bay in that same 2005-06 drilling season, but Pioneer later announced that well to be "unsuccessful."

Immediately south of Prudhoe Bay, the Alaska Department of Natural Resource has placed the Arctic Fortitude unit in default because, the department said, operator Alaskan Crude Corp. has failed to meet an obligation to move a drilling rig on site to re-enter the Burglin 33-1 well. The status of the unit is currently the subject of litigation between Alaskan Crude and the state in the State Superior Court.

Nearshore Beaufort Sea

Another possibility for explorers seeking opportunities near the existing infrastructure is to look north, under the nearshore waters of the Beaufort Sea. In fact, the BP-operated Endicott field, discovered in 1978 and involving a Barrow Arch Ellesmerian play, has demonstrated for a couple of decades that production from a nearshore oil field can prove profitable. Endicott operates from an artificial island connected by causeway to the mainland.

And although BP's 1983 Mukluk well in Harrison Bay, the most expensive dry hole in oil industry history, perhaps didn't set a good precedent for nearshore Beaufort Sea exploration, other projects have demonstrated that success is possible, despite the high economic barriers to offshore development.

BP, apparently undeterred by Mukluk, successfully brought the 202 million-barrel Northstar oil field (formerly known as Seal Island), just north of Prudhoe Bay, into production in 2001 from an artificial island. Northstar produces oil from the Ellesmerian Ivishak formation that forms the main reservoir at Prudhoe Bay. Fault blocks on the northern flank of the Barrow Arch trap the reservoir sand.

In 2002 Armstrong Oil and Gas, a small but feisty oil independent, permitted three Beaufort Sea wells in the shallow waters of Harrison Bay, northwest of the Kuparuk River unit. And, following the closure of a deal in which Pioneer Natural Resources took a 70 percent interest in the Armstrong leases, Pioneer drilled the wells, thus discovering the 120 million-to 150 million-barrel Oooguruk field in March 2003.

When Eni purchased Armstrong's Alaska assets in 2005, those assets included Armstrong's remaining interest in Oooguruk.

In June 2008 the start of production from Oooguruk, operated by Pioneer from an artificial island, brought the first northern Alaska oil from an independent producer online. Oooguruk production, which has been exceeding expectations, comes from two distinct Beaufortian sand reservoirs, the Kuparuk and the Nuiqsut. Pioneer is in the process of working through its development drilling program at Oooguruk to maximize field production, but has stated that it expects to use knowledge gained at Oooguruk to seek new development opportunities in the area around the existing field.

In January 2004 Armstrong pulled off a similar deal to Oooguruk by persuading Kerr-McGee to acquire 70 percent of Armstrong's Nikaitchuq unit, near Oliktok Point on the east side of Harrison Bay, and then experiencing the satisfaction of Kerr-McGee's discovery of the 180 million-barrel Nikaitchuq field shortly afterward. The Nikaitchuq oil occurs in two distinct reservoirs: light oil in the Ellesmerian Sag River sandstone and more viscous oil in the Brookian Schrader Bluff formation.

Eni started buying into the Nikaitchuq field in 2005, as part of its purchase of Armstrong's assets, and since 2007 has had 100 percent ownership of the field. The company is progressing development at Nikaitchuq but, following low oil prices and other complications since the summer of 2008, has deferred the likely startup date from 2009 to 2011.

Savant Alaska LLC was less fortunate in 2008 when testing its Kupcake prospect in the Beaufortian Kemik sands, in state Beaufort Sea acreage not far from BP's outer continental shelf Liberty field: The company plugged and abandoned its Kupcake No. 1 well after finding "water-wet" Kemik sands at a depth in excess of 10,000 feet.

In a state lease sale held in October 2008, Armstrong re-entered the northern Alaska oil industry by purchasing acreage around Kuparuk and to the west of Oooguruk, but there's no word yet of the company initiating any exploration activity in any of this acreage. In 2007 the company had purchased acreage in the southern Kenai Peninsula, in Southcentral Alaska, and has since drilled a gas well there.

Brookian plays

Exploration interest in the Brookian, the youngest and shallowest of the petroleum-bearing rock sequences of northern Alaska, mushroomed in the mid-1990s with successful tests of the mid-Cretaceous Tarn sands adjacent to the Kuparuk River field, the subsequent development of several Brookian Kuparuk satellite fields by ConocoPhillips and a move by BP to commercialize an earlier discovery of oil at Badami, the most easterly of the North Slope oil fields.

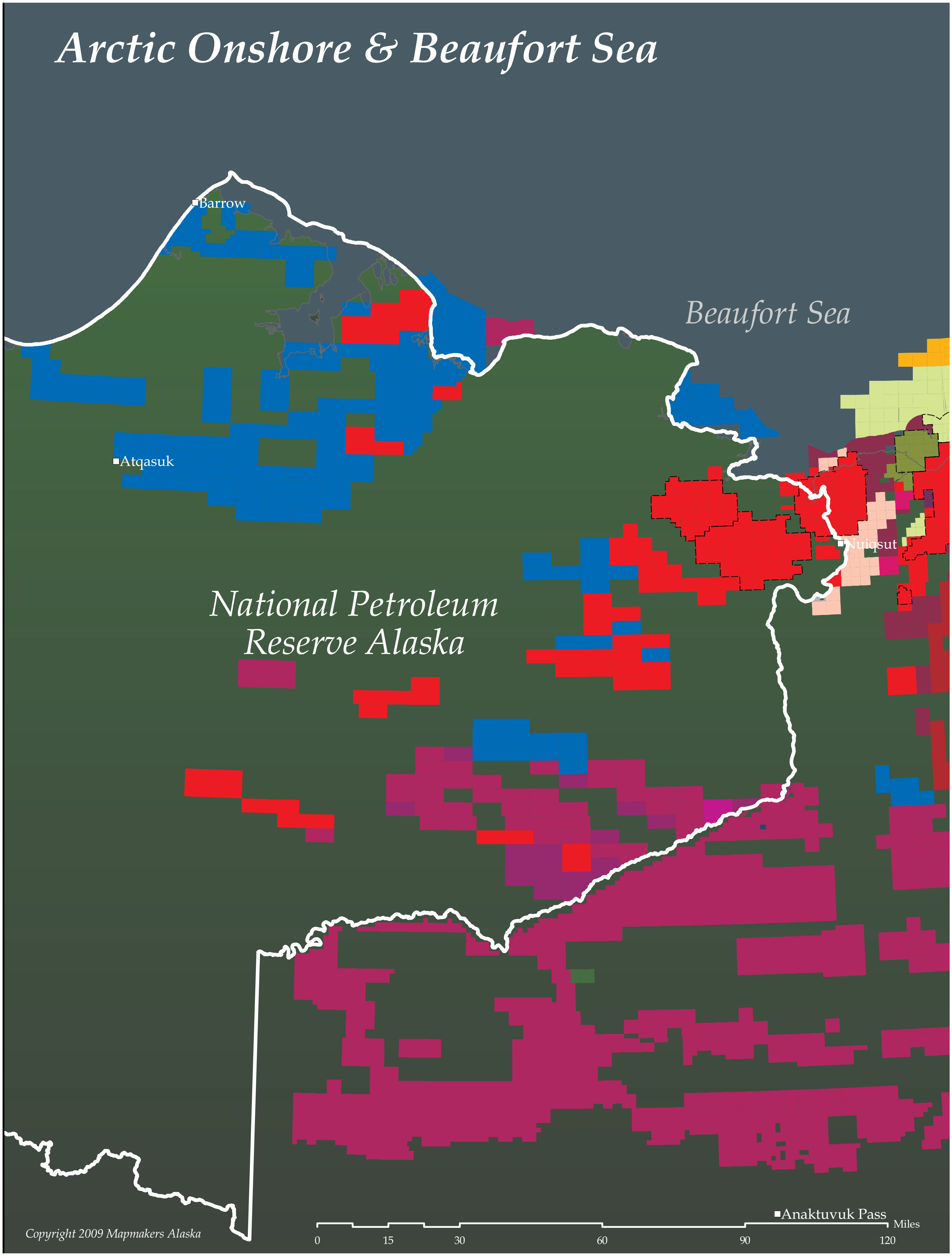
Exploration 3-D surveys began to carpet not only the areas flanking known production, but increasingly to areas where potentially productive trends could be extrapolated using 2-D data. In the eastern North Slope, BP and partners added oil finds at Sourdough and Yukon Gold to a previous find at Flaxman Island, as potential satellites to the Point Thomson field, the huge gas-condensate field near the western border of the Arctic National Wildlife Refuge.

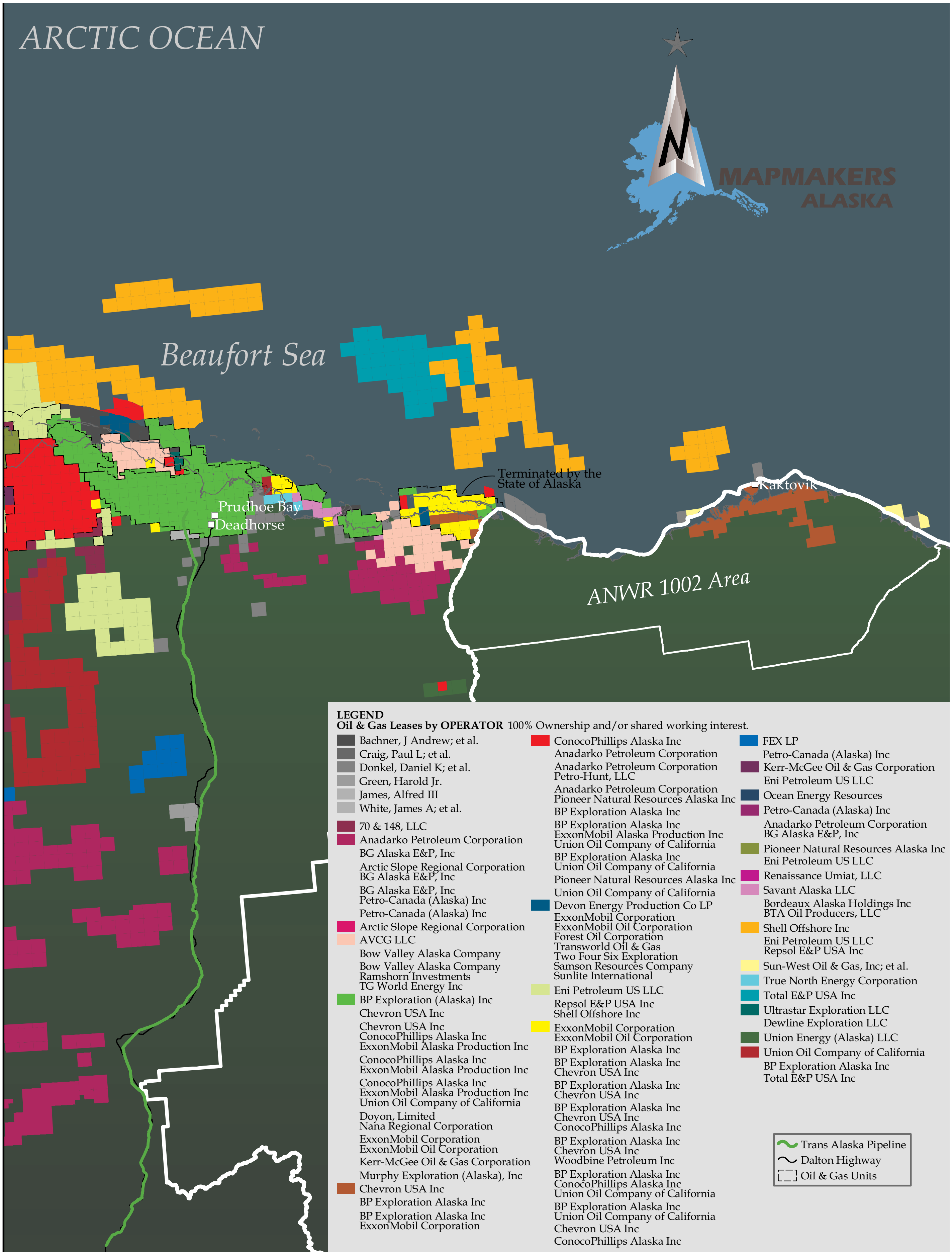
Unfortunately, development drilling at Badami confirmed earlier hints from both seismic and well data that its sand reservoir was less continuous and more highly compartmentalized than hoped. Production there has never lived up to design expectations and the field is currently in warm shutdown. Other similar eastern North Slope stratigraphic traps have not been evaluated in detail, and may well have better potential.

Exploration of the Brookian sand play continued, although apparently without much success, with drilling at the McCovey prospect offshore near Reindeer Island; the Heavenly and Grizzly wells south of Kuparuk; and the Hunter well in NPR-A. And companies continue to evaluate the play in NPR-A and elsewhere on the North Slope, sometimes as a secondary target.

Meantime Savant, under a farmout agreement with BP, started drilling its Red Wolf well at Badami in the winter of 2008-09 to test the Ellesmerian Kekiktuk formation, below and southwest of the Brookian Badami reservoir. The Kekiktuk is the reservoir formation for the Endicott field. Savant anticipates resuming the drilling of its Red Wolf well in the winter of 2009-10, after which the company plans to sidetrack a Badami well to test the productivity of a horizontal well in the challenging Badami reservoir.

continued on page 58


Arctic Onshore & Beaufort Sea
Barrow
Beaufort Sea
Atqasuk
Nuiqsut
National Petroleum Reserve Alaska
Anaktuvuk Pass
Miles
0
15
30
60
90
120
Copyright 2009 Mapmakers Alaska



ARCTIC OCEAN
MAPMAKERS ALASKA
Beaufort Sea
Terminated by the State of Alaska
Kaktovik
Prudhoe Bay
Deadhorse
ANWR 1002 Area
LEGEND
Oil & Gas Leases by OPERATOR 100% Ownership and/or shared working interest.
Bachner, J Andrew; et al.
Craig, Paul L; et al.
Donkel, Daniel K; et al.
Green, Harold Jr.
James, Alfred III
White, James A; et al.
70 & 148, LLC
Anadarko Petroleum Corporation
BG Alaska E&P, Inc
Arctic Slope Regional Corporation
BG Alaska E&P, Inc
BG Alaska E&P, Inc
Petro-Canada (Alaska) Inc
Petro-Canada (Alaska) Inc
Arctic Slope Regional Corporation
AVCG LLC
Bow Valley Alaska Company
Bow Valley Alaska Company
Ramshorn Investments
TG World Energy Inc
BP Exploration (Alaska) Inc
Chevron USA Inc
Chevron USA Inc
ConocoPhillips Alaska Inc
ExxonMobil Alaska Production Inc
ConocoPhillips Alaska Inc
ExxonMobil Alaska Production Inc
ConocoPhillips Alaska Inc
ExxonMobil Alaska Production Inc
Union Oil Company of California
Doyon, Limited
Nana Regional Corporation
ExxonMobil Corporation
ExxonMobil Oil Corporation
Kerr-McGee Oil & Gas Corporation
Murphy Exploration (Alaska), Inc
Chevron USA Inc
BP Exploration Alaska Inc
BP Exploration Alaska Inc
ExxonMobil Corporation
ConocoPhillips Alaska Inc
Anadarko Petroleum Corporation
Anadarko Petroleum Corporation
Petro-Hunt, LLC
Anadarko Petroleum Corporation
Pioneer Natural Resources Alaska Inc
BP Exploration Alaska Inc
BP Exploration Alaska Inc
ExxonMobil Alaska Production Inc
Union Oil Company of California
BP Exploration Alaska Inc
Union Oil Company of California
Pioneer Natural Resources Alaska Inc
Union Oil Company of California
Devon Energy Production Co LP
ExxonMobil Corporation
ExxonMobil Oil Corporation
Forest Oil Corporation
Transworld Oil & Gas
Two Four Six Exploration
Samson Resources Company
Sunlite International
Eni Petroleum US LLC
Repsol E&P USA Inc
Shell Offshore Inc
ExxonMobil Corporation
ExxonMobil Oil Corporation
BP Exploration Alaska Inc
BP Exploration Alaska Inc
Chevron USA Inc
BP Exploration Alaska Inc
Chevron USA Inc
BP Exploration Alaska Inc
Chevron USA Inc
ConocoPhillips Alaska Inc
BP Exploration Alaska Inc
Chevron USA Inc
Woodbine Petroleum Inc
BP Exploration Alaska Inc
ConocoPhillips Alaska Inc
Union Oil Company of California
BP Exploration Alaska Inc
Union Oil Company of California
Chevron USA Inc
ConocoPhillips Alaska Inc
FEX LP
Petro-Canada (Alaska) Inc
Kerr-McGee Oil & Gas Corporation
Eni Petroleum US LLC
Ocean Energy Resources
Petro-Canada (Alaska) Inc
Anadarko Petroleum Corporation
BG Alaska E&P, Inc
Pioneer Natural Resources Alaska Inc
Eni Petroleum US LLC
Renaissance Umiat, LLC
Savant Alaska LLC
Bordeaux Alaska Holdings Inc
BTA Oil Producers, LLC
Shell Offshore Inc
Eni Petroleum US LLC
Repsol E&P USA Inc
Sun-West Oil & Gas, Inc; et al.
True North Energy Corporation
Total E&P USA Inc
Ultrastar Exploration LLC
Dewline Exploration LLC
Union Energy (Alaska) LLC
Union Oil Company of California
BP Exploration Alaska Inc
Total E&P USA Inc
Trans Alaska Pipeline
Dalton Highway
Oil & Gas Units

TRENDS *continued from page 55*

Point Thomson

On the Beaufort Sea coast, just west of ANWR, ExxonMobil has finally started development drilling in the large Point Thomson gas condensate field. The company has completed the drilling and casing of the surface sections of a production well and an injector well to depths of about 4,800 feet, as part of a $1.3 billion gas cycling project at the field. The company has said that it plans to complete both wells to full depth by the end of 2010.

ExxonMobil has said it aims to produce 10,000 barrels of gas condensate per day from Point Thomson for shipment down the trans-Alaska oil pipeline.

The Alaska Department of Natural Resources had terminated the Point Thomson unit in late 2006 and subsequently taken back the associated leases because ExxonMobil had not developed the field in the 30 years or so since the field was discovered. DNR subsequently reinstated two of the leases, on condition that ExxonMobil proceeded with the development drilling. However, the status of the unit is still the subject of litigation.

Southwest of Badami, and 10 miles southeast of Prudhoe Bay, Anadarko, with partners BG Alaska and Arctic Slope Regional Corp., drilled its Jacob's Ladder well in 2007 and 2008 to a depth of 14,400 feet, to test an unusual but promising Ellesmerian prospect, somewhat equivalent to the Lisburne field at Prudhoe Bay, in what geologists believed to be ancient karst topography, a type of terrain where water erodes limestone to form underground caves that can, when subsequently buried, become good vessels for holding oil or gas. Unfortunately the well proved to be a dry hole.

In the winter of 2007-08 Chevron started a multiyear exploration drilling project in the White Hills region of the central North Slope, south of the Kuparuk River field, near the Dalton Highway. The company has said that it is exploring for both oil and gas but has not commented on the results of its drilling to date; although according to Alaska Oil and Gas Conservation Commission records the company drilled three White Hills wells in 2008 and two more wells in 2009.

Exploring through technology

BP, one of the first companies to explore on the North Slope, announced in 2001 that it was withdrawing from traditional exploration activities in Alaska, electing instead to develop new oil reserves by exploiting new technologies in existing oil fields, a strategy that it has termed "exploring through technology." Essentially the company substitutes the risk of trying unproven new technologies to exploit known resources for the risk involved in seeking unknown new fields.

In particular, the company has been pursuing this strategy as operator of the huge Prudhoe Bay field — with perhaps 25 billion barrels of original oil in place, just a small percentage increase in oil recovery from the field's massive subterranean reservoirs can amount to the production of a major amount of useful product that would otherwise remain underground and that could amount to the volume of oil recoverable in total from a modest size field elsewhere.

Techniques that BP has been using to increase oil recovery at Prudhoe Bay include precision directional and coiled-tubing drilling; the use of high-tech enhanced oil recovery techniques; and the use of 3-D and 4-D seismic surveying.

And both BP and ConocoPhillips have been using techniques such as the drilling of horizontal wells and multilateral wells — multiple wells branching out from a single vertical well bore — to render viable the production of thick viscous oil from the shallow Brookian West Sak and Schrader Bluff reservoirs above the Prudhoe Bay and Kuparuk River fields.

BP has also been researching the possible production of heavy oil — oil too thick to flow by itself down a pipeline — and has conducted some initial tests of a technique "called cold heavy oil production with sand," or CHOPS, at a well pad in the Milne Point field, extracting oil with a consistency of chocolate syrup from the shallow Brookian Ugnu formation.

Another possibility for the future, especially if a North Slope gas line is constructed, is the production of natural gas from methane hydrate, a solid compound in which methane molecules are trapped within the crystalline structure of frozen water. Hydrates are known to occur in large quantities around the base of the permafrost zone below the central North Slope. Methane is the main component of natural gas.

In 2007, as part of a joint industry, university and government gas hydrate research project, with some funding from the U.S. Department of Energy, BP successfully drilled the Mount Elbert gas hydrate stratigraphic test well at Milne Point, with the research team recovering gas hydrate samples and conducting some tests on the characteristics of the hydrates around the well bore. The team has since been evaluating possible sites for a gas hydrate production test, recognizing that much work remains to be done to determine whether it will be possible to produce gas from hydrates on a commercial basis.

ConocoPhillips is engaged in a parallel project with DOE, evaluating the potential to produce natural gas by injecting waste carbon dioxide into gas hydrate deposits.

And at the west end of the North Slope DOE and the North

Slope Borough are investigating the possibility that gas hydrates are contributing to production from gas fields near the city of Barrow.

National Petroleum Reserve-Alaska

THE NATIONAL PETROLEUM RESERVE-ALASKA, or NPR-A, consists of a 23 million-acre region at the western end of northern Alaska between the Beaufort Sea and Chukchi Sea coasts and the northern margin of the Brooks Range. The northern part of NPR-A lies within the coastal plain while the southern part straddles the Brooks Range foothills belt.

People have long known of the petroleum potential of this huge land area — surface oil seeps and oil-stained rocks provide evidence of active petroleum systems. In 1923 President Harding established the area, then known as the Naval Petroleum Reserve No. 4, as a potential source of oil supplies for the U.S. Navy. When jurisdiction over the reserve was transferred to the U.S. Bureau of Land Management in 1976, the name of the reserve was changed to the National Petroleum Reserve-Alaska.

The U.S. government conducted two exploration programs in NPR-A, one that led to several years of drilling by the U.S. Navy following World War II and one coordinated by the U.S. Geological Survey in the 1970s and 1980s. The earlier of these campaigns focused on exploring for strategic quantities of oil and gas, while the later phase went to greater lengths to develop a detailed understanding of the geology of the area.

These programs resulted in more than 14,000 line-miles of seismic surveys, 126 exploration wells and the 1946 discovery of a modest-sized oil field at Umiat on the Colville River. In 1985 ARCO drilled the Brontosaurus well to test an Ellesmerian prospect but the well proved dry.

The northeastern edge of NPR-A lies just south of the western extension of the Barrow Arch structure associated with the Prudhoe Bay field, but the huge Colville basin — filled with sediments of the Brookian sequence, folded and thrust-faulted along its southern side, adjacent the Brooks Range — dominates the geology of NPR-A.

1999 lease sale

In the northernmost part of NPR-A a Beaufortian play associated with the Alpine field in the neighboring Colville River Delta has proved a fruitful line of exploration following the advent of modern NPR-A leasing with a lease sale in 1999. This exploration trend, extending west from the existing North Slope oil infrastructure, is discussed in the central North Slope section of this publication.

The 1999 lease sale covered just the northeastern part of the reserve and resulted in ARCO, Anadarko, Phillips Petroleum and BP all ending up with acreage positions. ARCO and Phillips both later became part of what is now ConocoPhillips.

Although Anadarko subsequently drilled its own Altamura No. 1 exploration well in northeastern NPR-A, the company has conducted most of its northern NPR-A exploration in partnership with ARCO and, later, ConocoPhillips, with ConocoPhillips as operator.

That partnership conducted drilling in the extreme northeastern part of the reserve, relatively near the Colville River and the Alpine field, but leases from the 1999 sale also hosted more remote drilling, substantially further west, by BP at Trailblazer in 2001 and by Phillips at Puviaq in 2003. Drilling at Puviaq, to the west of Teshekpuk Lake about halfway between the Colville River Delta and the city of Barrow, at the extreme northwest end of the coastal plain, involved staging a drilling rig on an ice pad during the summer and using tundra off-road vehicles to transport personnel and equipment.

In a second northeast NPR-A lease sale in 2002, Phillips and Anadarko flagged their continued interest in the region by dominating the sale, building onto their existing lease positions. TotalFinaElf and EnCana Oil & Gas also bought leases at that sale, while BP confirmed its withdrawal from Alaska exploration by not bidding. In 2003 BP finally sold its NPR-A acreage from the earlier lease sale. EnCana dropped its NPR-A leases in 2004, eventually pulling the plug on all of its Alaska exploration interests toward the end of that year.

Northwestern NPR-A

Despite litigation by environmental groups concerned about the specter of oil and gas development expanding across much of the extreme northwest of Alaska, the U.S. Bureau of Land Management held its first lease sale for the northwestern part of NPR-A in June 2004. At that sale, Anadarko, ConocoPhillips, Pioneer, Petro-Canada and Fortuna Exploration all purchased leases. Fortuna, the Alaska subsidiary of Talisman, the Canadian independent that had already farmed into Total's NPR-A acreage, would later change its name to FEX.

But, following disappointment at its remote Caribou 26-11 well, jointly drilled with Fortuna in February 2004, Total appeared to lose interest in NPR-A, choosing not to bid in the June 2004 lease sale and assigning some of its leases to FEX.

The ConocoPhillips and Anadarko partnership continued its remote NPR-A exploration program by drilling two wells at the Kokoda prospect, at the end of a 70-mile ice road, in 2005. And in 2005 Anadarko told Petroleum News that its strategy in these remote areas was the discovery of large "anchor" fields that would be viable to develop and then form hubs for the development of smaller fields.

Also in 2004 and 2005, Pioneer signed NPR-A exploration agreements with ConocoPhillips and Anadarko, agreements that involved the acquisition by Pioneer of a 20 percent working interest in NPR-A acres and adjacent offshore acreage, additional to Pioneer's existing NPR-A holdings. In early 2007 ConocoPhillips, in partnership with Pioneer, drilled two NPR-A wells, both a long way from infrastructure: the Noatak No. 1 well, just north of Kokoda, and the Intrepid No. 2, south of Barrow, at the far western end of the North Slope, about 200 miles from the oil infrastructure of the Alpine field.

But in May 2007 ConocoPhillips declared both the Noatak and Intrepid wells to be noncommercial.

FEX: looking for big numbers

In the winter of 2005-06 FEX completed the Aklaq 2 well, the first of its NPR-A exploration wells, at a remote site some 140 miles west of Prudhoe Bay, using a Nabors drilling rig staged at Smith Bay on the Beaufort Sea coast. The company also shot some 3-D seismic on its leases. Talisman Executive Vice President John 't Hart said FEX was "looking at very big numbers" from its Alaska acreage — on the order of 250 million barrels of oil equivalent per prospect — with the potential to exceed 1 billion boe.

In July 2006 the U.S. Court of Appeals for the 9th Circuit affirmed a 2005 decision by the U.S. District Court for Alaska to reject the appeal against the June 2004 northwest NPR-A lease sale, thus clearing the way for oil and gas drilling in that part of the

continued on next page

TRENDS *continued from page 59*

reserve. In September of that year, however, the District Court put a halt to a planned northeast NPR-A lease sale, following an appeal by a number of environmental groups against that sale. The appeal, which was also supported by the North Slope Borough, focused on a proposal to open for leasing an environmentally sensitive area around Teshekpuk Lake, an area thought to be prospective for oil and gas because of its proximity to the Barrow arch, the geologic feature associated with most of the operational northern Alaska oil fields.

BLM did proceed with a northwestern NPR-A lease sale in September 2006, with FEX and Petro-Canada picking up substantial acreage. ConocoPhillips and Anadarko also bought some leases in the southern and central part of the northwestern planning area.

In the winter of 2006-07, in a two-rig program involving the use of Doyon's Arctic Wolf rig, transported from Prudhoe Bay, as well as the rig staged at Smith Bay, FEX drilled the Aklaqyaaq-1, Amaguq-2 and Aklaq-6 wells in northwestern NPR-A, eventually suspending three of the wells and plugging and abandoning Amaguq-2, which the company said was "subcommercial given current infrastructure."

300 million to 400 million barrels

But the company also revealed that it had encountered more than 225 feet of net hydrocarbon-bearing sandstones in several formations in two wells it had drilled and suspended. Based on log analysis and "strong gas and oil shows, including oil staining and free oil in the drilling mud in one of the wells," it said the "initial estimate of contingent resources present" in the formations of the two suspended wells was "300-400 million barrels" net to FEX, which had a 60 to 80 percent working interest in the leases with Petro-Canada.

However, Tim England, Talisman's senior manager of exploration, told Petroleum News in 2007 that FEX was pressing the pause button on its NPR-A exploration drilling, choosing instead to shoot some new 3-D seismic and spend some time evaluating its project areas. England commented on the high cost of drilling far from infrastructure in Alaska, and he also referenced the stymied northeast NPR-A lease sale program, saying that future drilling decisions would be driven in part by whether BLM got back on track with its NPR-A lease sales.

In September 2008, BLM finally held a lease sale for northeastern NPR-A, having withdrawn from the sale area the contentious land north and east of Teshekpuk Lake. ConocoPhillips, Anadarko, Petro-Canada, FEX and newcomer Petro-Hunt LLC all picked up NPR-A acreage in the sale. Petro-Hunt later relinquished its leases, as a consequence of the crash in oil prices later in 2008.

Following the lease sale Richard Garrard, FEX's geoscience manager in Alaska, told Petroleum News that the company's new leases built on its existing NPR-A position and that the company was reaching a point where it would be able to interpret a large 3-D seismic program shot on the company's NPR-A acreage.

In January 2009 't Hart told the Alaska Support Industry Alliance that FEX would not drill again in NPR-A until 2011, at the earliest.

In the 2008 NPR-A lease sale ConocoPhillips bought leases that consolidated its position around the Mooses Tooth unit, in the extreme northeast of the region, while Anadarko and Petro-Canada extended their lease positions around a natural gas play near Umiat — that play is discussed in Brooks Range foothills section of this publication.

Leases dropped

But meantime, following a lack of success in ultra-expensive, remote wells such as the Kokoda wells, Noatak and Intrepid, ConocoPhillips, Pioneer and Anadarko dropped 300,000 acres of NPR-A leases in September 2007. ConocoPhillips dropped additional acreage near Barrow in 2008, a move that reflected the company's clear intent to consolidate and move forward with exploration and development of prospects immediately west of the Alpine field.

In a September 2007 media briefing, Pioneer President and Chief Operating Officer Timothy Dove said that, following disappointing exploration drilling results both in the central North Slope and in NPR-A, Pioneer was suspending its Alaska exploration drilling program, focusing instead on developing its Beaufort Sea Oooguruk field and on investigating potential production from the Cosmopolitan prospect in the Cook Inlet.

And so, exploration drilling in the parts of northern NPR-A more distant from oil infrastructure is currently somewhat in a state of limbo, perhaps waiting for upward signals from global oil prices and certainly reflecting the greater ease of development closer to the central North Slope.

Brooks Range foothills

THE BROOKS RANGE FOOTHILLS, also referred to as the North Slope foothills, extend in a broad east-west swath of territory north of the Brooks Range, from the Chukchi Sea to the western edge of the Arctic National Wildlife Refuge. East of the Canning River the foothills belt becomes less distinct and trends north and east to the Canadian border and under the Beaufort Sea.

The foothills and the northern front of the Brook Range afford excellent opportunities to examine surface outcrops of rocks that lie deep underground elsewhere, and in recent years the region has become a subject for detailed investigation by a team from the Alaska Division of Geological and Geophysical Surveys in collaboration with the Alaska Division of Oil and Gas, USGS and oil industry geologists. Near the North Slope haul road the team found potential reservoirs and potential oil and gas source rocks equivalent to some of the more prolific sources of the North Slope. Oil stained sands in the area provide tantalizing evidence that oil migrated through the rock units. Geologists have interpreted one oil-stained location about 40 miles south of Umiat as a former oil field now breached by erosion.

The DGGS team has also found substantial outcrops of Ellesmerian carbonate rocks with reservoir potential.

Folding of the Brookian strata in the foothills gives rise to the potential for structural traps that are unlikely to exist farther north. This Brookian structural play is associated with the Umiat oil field. Several other small accumulations have been discovered in the fold belt trend of NPR-A, but they contain mostly gas.

In fact the relatively high thermal maturity and leaner organic content of Brookian rocks in most of the foothills area points to the formation of natural gas rather than oil — most people consider the Brooks Range foothills to be a gas prone province. However, evidence such as the Umiat oil field, oil-stained rocks at the surface and the discovery of at least some oil-prone source rocks in the region hints at the existence of some oil, perhaps derived in part from Ellesmerian or Beaufortian source rocks.

Umiat

The 1999 BLM northeastern NPR-A lease sale, although triggered by an interest in exploration west of the Colville River delta, opened the possibility of oil and gas leasing around the Umiat oil field, in the southeastern corner of the lease sale area. Low oil prices at that time discouraged Umiat development, but as prices started to climb a few years later the field caught the attention of Texas-based Renaissance Alaska LLC, spurring Renaissance to progressively buy into the relevant federal and state leases, to establish a lease position over the field.

In February 2008 Renaissance deferred an initial plan to drill seven or eight appraisal wells in the Umiat structure, electing instead to "de-risk" field development with a 3-D seismic survey. In September 2009 the company told Petroleum News that it was waiting for evidence of sustained high oil prices before making a decision on whether to proceed with development drilling at the field, saying that the seismic data coupled with data from the old wells drilled by the U.S. Navy had furnished sufficient information to determine whether development is viable.

A new assessment by Ryder Scott Co. had indicated that the two main reservoir sands in the field may contain about 250 million barrels of economically recoverable light, sweet 37 API oil, said Jim Watt, Renaissance president and CEO. There may be more than 700 million barrels of oil in place in those horizons and, when added to other oil in the shallow sands that have given rise to some well known oil seeps at Umiat, there may be more than 1 billion barrels of oil in place in the field, Renaissance thinks.

Renaissance is in the process of developing a business plan for Umiat, a plan that envisages the delivery of oil by pipeline to pump station 2 of the trans-Alaska oil pipeline. However, because the deepest oil at Umiat is only about 1,400 feet below the surface, the oil will be produced at temperatures of just 28 to 32 F, low temperatures that will present some unusual production challenges — Renaissance envisages pumping the oil, cold, down the export pipeline, rather than trying to heat up the oil for shipment.

Gas exploration

Apart from the work at the Umiat oil field, the gas-prone nature of the foothills petroleum geology, the known existence of some gas fields near Umiat and some significant moves toward the development of a natural gas export pipeline from the central North Slope have together triggered more of an interest in gas exploration in the foothills.

Anadarko has for more than a decade been the leading figure in this play.

In August 1998, the company signed an exclusive exploration agreement with Arctic Slope Regional Corp., granting Anadarko exploration rights for up to 3.3 million acres in the foothills region. Anadarko later brought in Alberta Energy Co. subsidiary AEC Oil & Gas (subsequently to become EnCana) and BP as one-third partners. Anadarko retained operatorship.

Anadarko said that it was interested in exploring for both oil and natural gas in the foothills, although the company has increasingly focused on natural gas in the region.

In state foothills lease sales held in 2001 and 2002, a partnership between Anadarko and EnCana added state acreage to their foothills portfolios, while EnCana purchased some leases in BLM's June 2002 NPR-A lease sale.

But in 2003 BP sold its foothills lease position to Anadarko as part of a BP strategic move to exit Alaska exploration. In early 2005 Anadarko established a new foothills partnership with Petro-Canada. Then, following EnCana's departure from Alaska in 2005, Anadarko found another foothills partner, BG Group, to buy a one-

continued on next page

TRENDS *continued from page 61*

third interest in the acreage held by Anadarko and Petro-Canada.

In the 2006 state areawide lease sale for the foothills region, Anadarko, Petro-Canada and BG jointly purchased additional acreage. Anadarko and Petro-Canada also bought some foothills acreage in the 2008 northeast NPR-A lease sale.

Anadarko and its partners had conducted seismic surveys in their foothills acreage but had been holding back on drilling, looking for a reasonable possibility of the development of a North Slope gas pipeline for the export of foothills gas. In 2007, with the passing of the state's Alaska Gasline Inducement Act, or AGIA, momentum toward gas pipeline development grew, thus upping the possibility of foothills gas ultimately become marketable.

During the winter exploration season of 2007-08, Anadarko, with partners BG and Petro-Canada, used Nabors rig 105-E to drill the Gubik No. 3 well and start drilling the Chandler No. 1 well, the first wells in northern Alaska to specifically target natural gas. Then, having over-summered the rig at Chandler on an insulated ice pad, Anadarko completed the drilling of the Chandler well in the winter of 2008-09.

Both wells sit near Umiat, near or at the known Gubik gas field, in Arctic Slope Regional Corp. land just outside the eastern boundary of NPR-A. Discovered by the U.S. Navy in 1951, Gubik is thought to hold some 600 billion cubic feet of recoverable gas in the Tuluvak and Nanushuk formations.

Chandler No. 1, about six miles southwest of Gubik No. 3, was drilled to about 10,200 feet; Gubik had a total depth of about 4,300 feet. According to Petro-Canada filings with the U.S. Securities and Exchange Commission, the Gubik No. 3 well tested at rates up to 15 million cubic feet per day of natural gas.

Also in the winter of 2008-09, Anadarko used the Doyon Arctic Fox rig to drill the Wolf Creek No. 4 well, at the site of another known gas accumulation in federal land inside NPR-A, about 40 miles west of Umiat.

Anadarko refers to the system of gas fields that it is evaluating as the "Gubik Complex."

Shipping the gas

The question of how companies exploring for gas in the Umiat area might eventually ship their gas to market depends on whether and when a main gas export line from the North Slope might be constructed — an obvious option would be to run a feeder gas line from Umiat over to the North Slope line. However, another option being considered both by the state and by Enstar Natural Gas Co, the main Southcentral Alaska gas utility, is a "bullet line" that would feed gas direct from the foothills into the Anchorage area, to supplement or replace the dwindling supplies of Cook Inlet gas for utility and industrial use.

The Alaska Natural Gas Development Authority has also proposed a spur line into the Anchorage area from a future North Slope gas line, and this type of spur line could also feed foothills gas into Southcentral Alaska.

Mark Hanley, Alaska public affairs manager for Anadarko, told Alaska legislators in February 2009 that gas was unlikely to be available to flow to market from any foothills gas field before 2016. If a North Slope export gas pipeline is constructed, that line would not come into operation until several years after that.

Renaissance has suggested that its development of the Umiat oil field, together with the Anadarko-led gas development in the area, could enable the sharing of environmental studies and pipeline or road rights of way among multiple projects, thus reducing project costs and perhaps establishing an Umiat bridgehead for further exploration and development in that part of NPR-A. And the state is considering building a gravel road from the Dalton Highway to Umiat, to support oil and gas development in the Umiat area.

But the acquisition of Petro-Canada by Suncor Energy in August 2009 has thrown another unknown into the foothills gas development equation: Suncor sees oil sands as its prime growth area and has been planning to sell some of its natural gas assets.

Beaufort and Chukchi seas outer continental shelf

A LACK OF INFRASTRUCTURE, HARSH WEATHER and extensive sea ice have long presented formidable barriers to anyone interested in exploring for oil in the remote waters of the Beaufort and Chukchi seas. Yet, with geology that forms a continuation of the prolific onshore petroleum systems of the North Slope, the Arctic outer continental shelf of Alaska presents some tantalizing opportunities.

In fact, exploration in the Beaufort Sea dates back to the early years of central North Slope development and exploration, with the Tern (later named Liberty) and Endicott fields being discovered in 1977 and 1978 respectively.

The state and the U.S. Minerals Management Service held a joint lease sale in 1979. Since then 30 exploration wells have targeted prospects in a range of plays from Ellesmerian to Brookian. The 202 million-barrel Northstar oil field (formerly known as Seal Island) straddling the edge of state nearshore waters just north of Prudhoe Bay went into production in 2001.

BP is now in the process of developing the Liberty field, on the outer continental shelf about 15 miles east of Prudhoe Bay, using record-breaking ultraextended-reach drilling from the satellite drilling island at the Endicott field. The Liberty reservoir is in the same Ellesmerian Endicott group that contains the reservoir for Endicott.

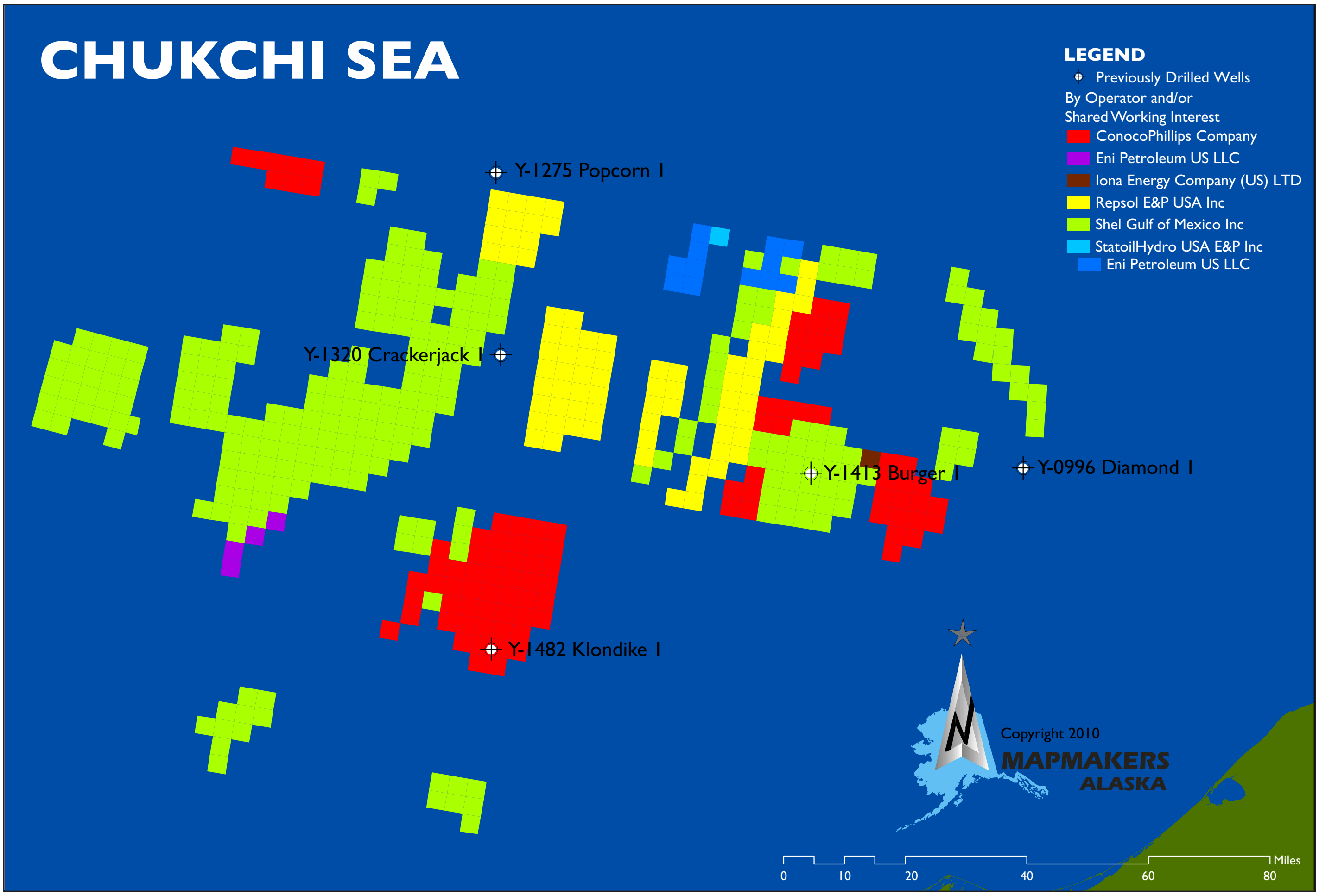
By using extended-reach drilling at Liberty, BP is avoiding the need for an offshore island and a connecting pipeline to the mainland. However, drilling extended-reach wells into reservoir targets some 8 miles from the surface drilling site has involved the construction of the world's most powerful land-based drilling rig, built by Parker Drilling Co. at a cost of more than $200 million. Other innovative technologies required at Liberty include the use of a new steel alloy for the drill pipe.

According to MMS there are three other known undeveloped fields in the Beaufort Sea: the 100 million- to 200 million-barrel Sivulliq field (previously known as Hammerhead), the 160 million- to 300 million-barrel Kuvlum field and the 12 million-barrel Sandpiper field. Sivulliq and Kuvlum are reservoired in faulted traps in Brookian sediments north of the western end of ANWR while Sandpiper occupies the Sadlerochit reservoir in a series of fault blocks farther northwest, on the same trend as Northstar.

Chukchi Sea

Exploration in the Chukchi Sea has been sparser than in the Beaufort.

Between 1989 and 1991 a group of companies led by Shell did drill five exploration wells in the Chukchi, focusing on structures with similar features to the North Slope oil fields. One well, the Klondike well, drilled into a 1,000-foot section of rocks correlative to the Sadlerochit group that includes the main reservoirs at



Prudhoe Bay. Unfortunately, this well found that the Sadlerochit under the central to southern part of the Chukchi consists mainly of shale rather than reservoir-quality sandstone.

But all of the wells encountered some hydrocarbons and one well, the Burger, found natural gas in a Kuparuk-equivalent sandstone reservoir 25 miles in diameter. MMS estimates this accumulation contains somewhere between 8 trillion and 27 trillion cubic feet of recoverable gas and between 31 million and 1,700 million barrels of condensate, with most likely values of about 14 tcf of gas and 724 million barrels of condensate. The Klondike well found very thick Triassic source rocks, largely equivalent to the prolific Shublik formation of the North Slope. Several of the wells encountered thick, high-quality reservoir rocks: 575 feet of Permian sandstone in the Diamond well and 540 feet of Paleocene sandstone in the Popcorn well.

A future exploration program in the Chukchi probably needs to focus on looking at the area on its own merits, rather than trying to find Prudhoe Bay lookalikes. For example, there may be as much as 20,000 feet of untested stratigraphic section below the deepest rock units drilled in the 1990s.

And the need for the oil majors to find new oil reserves in increasingly challenging places, in the face of continuing world oil demand and the maturing of existing oil basins, appears to be driving an increasing interest in offshore Arctic exploration.

In particular, sustained high oil prices in 2005-06, coupled with forecasts of continued upward price pressure and the emergence of new offshore exploration and development technologies, triggered new moves toward OCS exploration. Shell led the charge in the Beaufort Sea with its purchase of a broad swath of leases, including the Sivulliq field, in the MMS 2005 Beaufort Sea lease sale. ConocoPhillips also purchased a substantial lease position in that sale.

Shell and ConocoPhillips shot 3-D seismic in the Chukchi Sea in preparation for a February 2008 MMS lease sale, where Shell was top bidder on 275 blocks for $2.1 billion and ConocoPhillips was runner-up with high bids of $506 million on 98 tracts. Repsol, Statoil and Eni were next in line.

A cluster of mega-bids in the Chukchi sale signaled interest by Shell and ConocoPhillips in the major Klondike and Burger structures that had been drilled in 1989 and 1990.

Shell in the Beaufort

Following the 2005 Beaufort Sea lease sale, Shell planned to start its offshore drilling program in the summer of 2007, with two drilling vessels, the Kulluk and the Frontier Discoverer, earmarked to drill three wells at Sivulliq as the first phase of an exploration plan that would involve drilling three to four wells per year until 2009.

The company assembled a small fleet of vessels for its Beaufort Sea program.

But litigation by the North Slope Borough, other North Slope communities and numerous environmental groups primarily directed against government approval of Shell's plans, but also directed against outer continental shelf lease sales, stymied Shell's offshore drilling plans. The company's Beaufort Sea drilling has not yet taken place, although Shell has conducted further 3-D seismic

continued on next page

TRENDS *continued from page 63*

surveys in both the Beaufort and Chukchi Seas, as well as doing some well site preparation work. Shell and Eni have also conducted a 3-D seismic survey in some Beaufort Sea joint venture leases in Harrison Bay.

Shell and ConocoPhillips have implemented offshore acoustic monitoring technology to detect the activities of marine mammals in the Beaufort and Chukchi Seas. Shell is evaluating the use of unmanned aerial vehicles for wildlife monitoring. And the company has set up communications centers in North Slope villages, to help coordinate industrial activities with the activities of subsistence hunters.

In May 2009 Shell finally withdrew its ill-fated 2007 to 2009 Beaufort Sea exploration plan, opting instead for a much-reduced plan involving the use of a single drilling vessel, the Frontier Discoverer, to drill one well in the Sivulliq prospect and one well in the nearby Torpedo prospect during the open water season of 2010. That plan is working its way through the MMS approval process. And following litigation over its air quality permitting, Shell has committed to upgrades to the exhaust systems on the Frontier Discoverer and has submitted to the U.S. Environmental Protection Agency an application for a major air quality permit, with the timely processing of that application being critical to the company's 2010 exploration program.

Shell says that its new Beaufort Sea plan addresses concerns that were raised about the cumulative impacts of its proposed offshore activities and that the plan encompasses measures agreed to with North Slope communities to protect offshore subsistence hunting.

Chukchi plans

Shell also plans to drill up to three exploration wells in the Chukchi Sea in 2010, in the Burger, Crackerjack, and Southwest Shoebill prospects. The Crackerjack prospect was the target of a Shell well drilled in 1990-91. The Southwest Shoebill prospect lies 20 to 30 miles southwest of Crackerjack and has not previously been drilled. In late 2008 ConocoPhillips signaled its intention to focus its offshore exploration on the Chukchi Sea rather than the Beaufort Sea by relinquishing most of its Beaufort Sea outer continental shelf leases. The company hopes to drill in the Chukchi Sea in 2011, and in 2008 the company commenced shallow hazards surveying and coring operations at Klondike, a prospect that the company now calls "Devil's Paw."

However, two as-yet unresolved legal issues still hang over exploration plans for the Chukchi Sea.

In April 2009 the United States Court of Appeals for the District of Columbia upheld an appeal against the MMS 2007 to 2012 outer continental shelf lease sale program that included the 2008 Chukchi Sea lease sale, thus putting the results of that sale into question. The court has instructed MMS to rework its environmental analysis for the Environmental Impact Statement for the lease sale, and the outcome of that rework is as yet unknown.

And a legal case in the U.S. District Court for the District of Alaska, involving an appeal against the 2008 Chukchi Sea lease sale, is also waiting for the results of the new EIS environmental analysis.

The U.S. Department of the Interior is also reconsidering its policy for future outer continental shelf lease sale programs, with environmental concerns relating to the Arctic offshore and the need for new U.S. energy supplies vying for the agency's attention.

Business opportunities and challenges in northern Alaska

THE HIGH COST OF NEW OIL EXPLORATION, development and production in Arctic Alaska has in the past resulted in the North Slope oil industry being the exclusive domain of oil majors, in particular ConocoPhillips (previously ARCO) and BP. However, as the region has matured as an oil province, smaller independent oil companies have made inroads into the region: In 2008, a banner year for independents on the North Slope, Pioneer Natural Resources brought the Oooguruk field in state waters of the Beaufort Sea online, the first production in northern Alaska by an independent oil company.

And although in the early days of the North Slope viable oil development in remote territory at vast distances from oil markets required giant oil fields, the established oil infrastructure is now opening up the possibility of bringing more modest-sized fields on line, as the older fields decline. In fact, the Oooguruk field processes its products in facilities at Kuparuk, and potential access to the existing infrastructure has led to active exploration in the Prudhoe Bay area by small companies such as Brooks Range Petroleum and Ultrastar.

Charter for development

A key factor, especially for small companies wanting to explore on the North Slope, is the existence of the Charter for the Development of the Alaskan North Slope, the charter that resulted from the settlement between the State of Alaska, BP and ARCO when BP purchased ARCO in 1999. Under the charter both BP and ConocoPhillips, the two major North Slope operators, have to be willing to negotiate the shared use of their facilities with new producers, and must buy third-party oil for shipment down the trans-Alaska oil pipeline. The charter also makes certain seismic data available to small companies, a major factor in reducing exploration costs.

However, companies wanting to negotiate facility access need to recognize that facility sharing will incur costs, including the potential cost of the impact of third party processing on production from the facility operator's own fields.

And the cost of shipping oil to market, including the tariff for shipping the oil on the trans-Alaska pipeline and the cost of carrying the oil by tanker from Valdez at the southern end of the pipeline, is a major factor in the economics of North Slope oil. The pipeline tariff, a topic of much controversy and dispute among oil shippers, pipeline owners, government regulators and the State of Alaska, tends to rise as North Slope production declines, as the pipeline fixed costs become spread across progressively fewer barrels of oil.

On the other hand, the trans-Alaska oil pipeline owners and Alyeska Pipeline Service Co. have done major upgrades to the pipeline system and the Valdez Marine Terminal, to improve the pipeline system efficiency and to enable the pipeline to more cost-effectively adjust to variations in throughput.

Very expensive

Oil exploration and development in northern Alaska is also much more expensive than in, say, the Lower 48, in part because of the logistical difficulties of working in a harsh climate in an extremely remote region, and in part because of the seasonal nature of most work.

The seasonal nature of the work results from the fact that, onshore, almost all off-road or off-gravel pad drilling or construction needs to be done during the winter, when the tundra is frozen and protected by a layer of snow. In fact, both the State of Alaska and the U.S. Bureau of Land Management have rules and procedures for determining when they will allow off-road travel on state or federal land, ensuring that the tundra will not be damaged but also limiting any work off the established road system to just a few months of the year.

And access to a remote site typically requires construction of an ice road, with the road construction adding to project costs and eating into the time available for work at the site.

During a remote exploration drilling project, for example, it may only be possible to drill a single well in one winter exploration season; it then becomes necessary to wait until the following winter to drill another well. If a new field is found, appraisal drilling may extend over several winter seasons, significantly delaying the start of field production.

This seasonality of exploration and development characterizes the steady march west toward and into northeastern NPR-A by ConocoPhillips and Anadarko, with the drilling of one or two new wells each winter. And in the foothills around Umiat Anadarko and its partners have been doggedly proceeding, a well or two at a time, in their investigation of the gas potential of what they term the "Gubik Complex."

Environmental permitting is also a critical issue for oil companies operating on the North Slope — no one can allow environmental mismanagement or an environmental disaster to damage the fragile Arctic environment. A serious environmental incident could cause irreparable damage to the oil industry's "license to operate" in the far north.

However, despite a view among some that strict environmental controls in Alaska place difficult obstacles in the way of would-be oil and gas explorers, and criticism of what some perceive as undue complexity in the permitting process, independent companies such as Anadarko, Pioneer, Brooks Range Petroleum and Ultrastar have demonstrated that, with appropriate expertise, the maze of environmental regulations can be successfully mastered.

OCS challenges

Exploration on the outer continental shelf of the Beaufort and Chukchi seas introduces a whole set of special challenges, including the immensely high cost of operating in ice-infested seas in a region of great environmental sensitivity. OCS exploration and development is the domain of major oil companies, with Shell spearheading efforts to expand exploration into the Arctic offshore, and with ConocoPhillips also adding OCS prospects to its exploration portfolio.

OFFSHORE DIVERS

The Nanuq, Shell's purpose-built oil spill response vessel for Arctic use. Following a recommendation from people on the North Slope, the company had the boat painted blue and white to avoid frightening whales.

The standard mode of operation for offshore drilling involves the use of an ice-reinforced drilling vessel, guarded from sea ice by ice breakers. Drilling has to be carried out during the relatively short open water season, lasting perhaps from early July into late October.

And, just to support its oil spill contingency plan for drilling in the Beaufort Sea, Shell has assembled a formidable fleet that has included a new purpose-built oil spill response vessel, an oil spill response barge and a 500,000-barrel-capacity oil tanker.

But Shell, hoping to start an aggressive Beaufort Sea drilling program in 2007, ran into a barrage of opposition from environmental groups, concerned about the possible impact of industrial activities on the delicate offshore environment, and by North Slope communities, concerned both about environmental impacts and about possible disruption of their traditional subsistence hunting, especially the hunting of bowhead whales.

Oil spill response

In addition to questioning the impact of industrial noise on marine mammals, people have challenged the practicality of responding to an oil spill in ice-infested waters. Oil companies such as Shell say that, while modern drilling technologies have all but eliminated the possibility of a significant offshore oil spill, technologies and expertise for oil spill response have advanced to the point where an Arctic oil cleanup is very practical. Critics say that the risk of an offshore oil spill cannot be eliminated and that oil recovery techniques for use in ice-laden waters are as yet unproven.

The North Slope Borough, in particular, has expressed concern about the speed and scale of what Shell had originally proposed to do. In fact, although most North Slope communities support onshore oil and gas development, those same communities have many reservations about offshore development, often characterizing the Arctic seas as their "garden," an essential resource for their traditional culture.

In response, Shell says that it respects the needs of the North Slope communities, and is taking care to accommodate those needs. The company says that offshore oil and gas development will provide jobs and careers for Alaskans, and that new oil from offshore will extend the life and improve the economics of the trans-Alaska oil pipeline, as well as provide new sources of much needed oil for the United States.

Following litigation that has prevented Shell from commencing its planned drilling in the Beaufort Sea, the company has now significantly scaled back its offshore drilling plans. The company says that it is responding to the concerns of the North Slope communities. In the open-water season of 2010 the company hopes to be

continued on next page

TRENDS *continued from page 65*

able to demonstrate that it can drill safely in the Arctic offshore, by drilling two wells in the Beaufort Sea and one well in the Chukchi Sea. ConocoPhillips hopes to drill in the Chukchi Sea in 2011.

North Slope gas pipeline

Work by TransCanada and ExxonMobil toward the Alaska Pipeline Project, and by Denali – The Alaska Gas Pipeline, is bringing closer the possible construction of a pipeline to transport natural gas from the North Slope to the Lower 48. And the future possibility of a North Slope gas pipeline has some bearing on the focus of petroleum exploration and development in northern Alaska.

On the North Slope, BP is planning how best to transition into gas production at the giant Prudhoe Bay field, the biggest initial source of gas for a pipeline. To date, gas produced from the field has been mostly re-injected into the field reservoir to maintain reservoir pressure and to coax as much oil as possible from the reservoir rock. BP, working in conjunction with the Alaska Oil and Gas Conservation Commission, must find a way to produce gas without unduly compromising the ultimate volume of oil recovered from the field.

To the east of Prudhoe Bay, ExxonMobil has finally started development drilling at the Point Thomson field, the other field considered to be a primary source of gas for a gas pipeline. Point Thomson is a gas condensate field and ExxonMobil has embarked on a project to prototype the production of condensate from the field using a gas cycling procedure. Condensate has a higher economic value than natural gas, a situation that, despite the huge volumes of gas at Point Thomson, drives a need to give condensate production priority over gas production, at least until as much condensate as possible has been produced.

And the improving odds of a North Slope gas pipeline coming into existence have driven a flurry of exploration activity in the gas-prone region of the North Slope foothills, with Anadarko and its partners drilling wells in known gas fields such as Gubik in the region around Umiat on the Colville River. An interest by several companies in oil and gas leasing in the foothills region in recent years presumably also reflects a view that the long-anticipated gas pipeline concept is starting to emerge from being an interesting idea into becoming a more solid reality.

Petroleum geology of northern Alaska

THE GEOLOGICAL HISTORY of northern Alaska has resulted in four distinct rock sequences. From oldest to youngest, these sequences are known as the Franklinian, Ellesmerian, Beaufortian and Brookian. People also refer to the Franklinian as the pre-Mississippian sequence and the Beaufortian as the rift sequence.

The oldest rock sequence, the Franklinian, formed on a stable continental platform before middle Devonian time (about 400 million years ago). The sequence contains a wide range of rock types, some of which may have been laid down as sediments on subsea slope deepening to the south.

The Franklinian sequence is often considered nonprospective "basement" due to its high thermal maturity and generally poor reservoir quality. However, shows of migrated oil are common in basement penetrations along the Barrow Arch; wells in the Point Thomson area have penetrated zones of dolomites with reservoir potential; and the Point Thomson gas condensate reservoir includes Franklinian carbonates. Economic production from pools in the Franklinian remains a possibility at some point in the future.

Franklinian sequence deposition ended across most of northern Alaska with a cycle of middle to late Devonian mountain building and metamorphism.

The Ellesmerian

Ellesmerian sediments, eroded from uplifted Franklinian rocks in a landmass that lay mostly to the north of the modern Beaufort Sea coast, spread southward and accumulated in the coastal and marine settings of an ancient basin known as the Arctic Alaska basin. Deposition of these sediments on a continental margin, sloping to the south, persisted into early or middle Jurassic time.

Deposited in highly varied marine-to-nonmarine settings over at least 150 million years, Ellesmerian strata constitute a diverse suite of rock formations, including prolific petroleum source rocks, excellent reservoirs and strong seal units that collectively define a self-contained, world-class petroleum system.

The strata of the Ellesmerian sequence tend to thin to the south, under the North Slope, because of the increasing distance from the source of the sediments in the north. They also tend to thin to the north of the North Slope, in the area of the ancient Ellesmerian landmass, in part because deposition was truncated against the landmass and in part because later uplift caused erosion of any sediments that had earlier been deposited.

The Beaufortian sequence

The Beaufortian sequence dates from between early to middle Jurassic and early Cretaceous and resulted from sediment deposition during major rifting or pulling apart of the earth's crust. People have proposed several hypotheses for this rifting. However, most geologists interpret the rifting as a result of the opening up of the Canada basin of the Arctic Ocean by a counterclockwise rotational movement of the North Slope Ellesmerian landmass away from equivalent platform rocks in Arctic Canada.

The east-west trending structural high known as the Barrow arch developed along the present Beaufort Sea coast. According to the most widely accepted Beaufortian rift model the arch formed in multiple uplift phases. The northern flank of the arch slopes steeply in a system of faults toward the Canada basin of the Arctic Ocean. The southern flank slopes very gently.

Widespread surface erosion along the Barrow arch probably occurred several times but culminated during the early Cretaceous to form an unconformity of regional east-west extent. This lower Cretaceous unconformity forms an important hydrocarbon migration and accumulation element for many of the oil fields on the North Slope, including the Prudhoe Bay field.

Most of the Beaufortian sediments eroding from the rising Barrow arch likely drained off the gentle southern flank of the arch, where they later became buried deep beneath younger sediments of the Brookian sequence. Other erosion products from the Barrow arch no doubt drained into the depths of fault-dropped blocks on the north side of the arch. Beaufortian sediments also accumulated in a variety of mostly shallow marine settings on the uplifted margin of the Barrow arch. These sediments formed important sandstone reservoirs in subtle low points on the arch or perched on rift-related fault blocks stepping off the arch to the north. Key examples include the Lower Cretaceous Kuparuk formation sandstones of the Kuparuk River and Point McIntyre fields and the Upper Jurassic Kingak formation sandstones of the Alpine field.

The Brookian

Also in late Jurassic and early Cretaceous time the Brooks Range started to form, sending thick sheets of thrust-faulted rock to the north. These thrust sheets loaded and depressed the earth's crust and caused a deep depression called the Colville basin to start to sink along the northern side of the range, between the range and the Barrow arch.

Sediments eroded from the Brooks Range thrust sheets poured into the Colville basin, progressively filling the basin from southwest to northeast and forming the Brookian sequence. Brookian sediments also spread out over the Barrow arch and onto Alaska's continental margin during Cretaceous-through-Tertiary time.

In very general terms, the older, lower Brookian sequence sediments tend to consist of shales and sandstones deposited in water hundreds or thousands of feet deep. The rocks higher in the sequence typically consist of sandstones and shales associated with coastal plains, river deltas or other shallow-water environments.

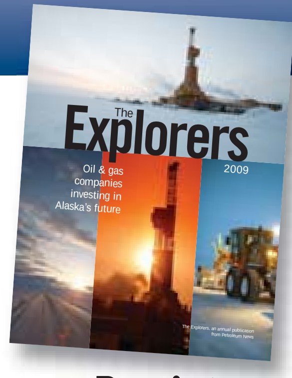
While sediments filled the Colville basin, the area of active sedimentation moved eastward. As a result, the Brookian rocks tend to become younger from west to east in the basin.

Nowadays Quaternary sediments cover the older bedrock along the North Slope. Most Quaternary deposits consist of unconsolidated sand and gravel, containing re-worked Brookian sediments along with materials from the present-day Brooks Range. Overlying these deposits are river-deposited silts and sandy silts that include variable amounts of organic matter. In addition to river deposits, windblown sands within the Quaternary sequence mark cold, dry Ice Age conditions. ■

The Anna platform in the Granite Point field.

By Alan Bailey
Petroleum News

Cook Inlet, a major sea inlet between the Kenai Peninsula and the mainland of Southcentral Alaska, lies over part of a deep sedimentary basin that has formed between the Kenai Mountains and the mountains of the Alaska and Aleutian ranges. This basin, known as the Cook Inlet basin, became a focus of early Alaska oil and gas exploration, hosted the first major Alaska oil field and remains an active target for oil and gas exploration and production. In its entirety, the basin extends beyond Cook Inlet under the western side of the Kenai Peninsula, under the lower land on the west side of the inlet and under the waters of the Shelikof Strait.



Reprint

This section is a reprint from Petroleum News' annual Explorers magazine, which was written in October 2009.

Oil remains exploration target

ALTHOUGH IN RECENT YEARS the Cook Inlet basin exploration focus has tended to move from oil to natural gas, there is still a market for oil, especially for use in Tesoro's Nikiski refinery on the Kenai Peninsula.

Pioneer Natural Resources is investigating the feasibility of developing a known oil accumulation in the Cosmopolitan unit, offshore west of the southern Kenai Peninsula near Anchor Point. The field would be developed from onshore using extended-reach drilling if Pioneer sanctions it. Oil from Cosmopolitan would probably be trucked to Nikiski.

In 2007-08 Pioneer successfully drilled the Hansen 1A-L1 sidetrack well at Cosmopolitan and tested the production of 400 to 500 barrels per day of oil. The drilling also found the potential for some gas production, probably through a 16-mile pipeline that would have to be constructed to connect with the Kenai Kachemak pipeline to the north.

Pioneer had planned to drill a second Cosmopolitan delineation well in 2009, but the collapse of oil prices in the wake of the evolving 2008 world economic crisis caused the company to place its drilling plans on hold. Meantime, the company is continuing to analyze the results from its previous well, to work on the project design and to deal with the permitting.

Chevron, which acquired all of Unocal's Cook Inlet oil fields and oil facilities when it took over that company in 2005, has ambitious plans to extend the life of its offshore Cook Inlet oil fields and to explore for new oil reserves. In March 2008 the company drilled two wells to try to establish new oil from the Anna platform in the Granite Point field, which lies on the west side of Cook Inlet.

The company told Petroleum News in November 2008 that, although the results from those Anna wells had proved disappoint-

continued on next page

COOK INLET *continued from page 69*

ing, a $100 million to $200 million Cook Inlet oil exploration program was still moving ahead, albeit with a possible re-evaluation in the light of collapsed oil prices.

But it is unclear what the long-term impact of the early 2009 eruption of Mount Redoubt volcano will be on oil exploration and development on the west side of Cook Inlet. The eruption caused the temporary shut-in of the Drift River oil terminal, located at the base of the volcano and providing the only means of exporting oil from the west Cook Inlet oil fields. The terminal reopened in August, but with its tank farm bypassed and a tanker having to call in every two weeks to offload oil piped to Drift River directly from storage tanks at production facilities at Granite Point and Trading Bay. The terminal shut-in caused the oil fields on the west side of Cook Inlet to also be shut-in for several months, with possible long-term impacts on field production rates.

Gas producers look for new resources

MARATHON, CONOCOPHILLIPS AND CHEVRON are the main producers of natural gas from the Cook Inlet basin.

For several years Marathon has been carrying out a program of infield drilling to sustain gas deliverability from its existing gas fields, primarily from the Kenai and Ninilchik fields on the Kenai Peninsula, using its own Glacier 1 rig.

However, the company has been evaluating a gas prospect called Sunrise in the northern part of the Kenai Peninsula. Also known as East Swanson, the prospect lies in a Cook Inlet Region Inc. holding inside the Kenai National Wildlife Refuge.

The company has now acquired some 2-D seismic for the prospect and plans to drill there in 2009.

ConocoPhillips, operator of the offshore North Cook Inlet gas field and the Beluga River gas field on the west side of the inlet, has recently been engaged in a new spurt of Cook Inlet drilling activity in these fields. In January 2009 the company announced a 20 percent cut in its Alaska capital spending, but the company did not say whether this cut would impact its Cook Inlet drilling plans.

Chevron drilled two development wells in the Grayling gas sands on the west side of Cook Inlet in 2008. And on the Kenai Peninsula, Chevron used the Nabors 106E rig to drill a new gas development well in the aging Swanson River field, and to drill two gas development wells in the Happy Valley field.

The company also plans to use the Nabors 129 rig that ConocoPhillips has been using at Beluga River to drill two new delineation wells in the Ivan River and Stump Lake gas fields on the west side of Cook Inlet. The idea is to develop new production from these old gas fields.

Independents explore for gas onshore

HOUSTON-BASED AURORA GAS was formed in 2000 to pursue natural gas opportunities in the Cook Inlet region, mainly focusing on known, relatively shallow gas plays. The company operates five gas fields on the west side of Cook Inlet: the Kaloa, Lone Creek, Moquawkie, Three Mile Creek and Nicolai Creek fields.

After a nearly two-year hiatus in drilling activity as a result of litigation over a suspended gas supply contract with Enstar Natural Gas. Co., the Southcentral Alaska local distribution company, Aurora Gas restarted operations with its AWS-1 rig in the late summer of 2008, doing some development and workover drilling in its gas fields.

Aurora Gas has a joint venture agreement with Swift Energy Co. for exploration drilling on Aurora acreage in the Cook Inlet basin. The joint venture drilled a dry wildcat well in the Endeavour oil prospect near Anchor Point on the Kenai Peninsula in 2006. Since then, as a result of a change in exploration focus by Swift and a lack of interest by Kaiser Francis Oil Co., Aurora's major owner, in further Cook Inlet exploration drilling, Aurora has placed its exploration ideas on hold.

In 2008 Armstrong Cook Inlet LLC, the Alaska affiliate of Denver-based Armstrong Oil and Gas Co., successfully drilled a delineation well in a known gas pool in the North Fork unit in the southern Kenai Peninsula. Field viability requires a price above $7 per British thermal unit and the company is now looking for a purchaser for the gas, Ed Kerr, Armstrong's vice president of land and business development, told the state House Resources Committee in March.

In September the company announced that it had signed a contract with Enstar to supply North Fork gas to Enstar. The contract requires Enstar to construct a gas pipeline south from the Kenai Kachemak pipeline to Anchor Point, northwest of Homer. The unit owners at North Fork have committed to build a pipeline west from North Fork to connect with the new Enstar line, and to drill two new gas wells at North Fork.

The gas supply contract with Enstar requires approval by the Regulatory Commission of Alaska.

The proposed new pipelines connecting to North Fork could open up the possibility of developing other gas prospects in the southern Kenai Peninsula.

Offshore drilling requires jack-up rig

SOME OF THE LARGER KNOWN oil and gas prospects in the Cook Inlet basin lie under the waters of Cook Inlet, in a geologic trend that extends southwest from ConocoPhillips' venerable North Cook Inlet gas field, the offshore field that was established as the primary gas source for the Nikiski LNG plant on the Kenai Peninsula.

These prospects consist of Northern Lights, Corsair, Kitchen and East Kitchen.

The Northern Lights prospect lies in a down dip extension of the undeveloped Sunfish oil discovery underneath the North Cook Inlet field. Corsair, in the middle of Cook Inlet to the southwest of Northern Lights, consists of a large NNE-SSW trending anticline with both gas and oil possibilities in multiple horizons. Kitchen lies along the same structural trend, southwest of Corsair. East Kitchen lies in an anticline about six miles northeast of Port Nikiski.

The only one of these prospects that has ever been drilled is Corsair, where Shell, Phillips and ARCO drilled a total of five exploration wells between 1962 and 1993. The wells all had gas shows and some also tested small quantities of oil.

Unfortunately, drilling in any of the prospects would require bringing a jack-up rig to Cook Inlet, probably from the Gulf of Mexico, an expensive and financially risky undertaking.

Independents push for jack-up

However, for several years Houston-based independent Escopeta Oil, under Danny Davis, its president, has been championing the cause of using a jack-up rig to drill some new exploration wells in Cook Inlet. Escopeta has particularly focused on the Kitchen prospect, where it holds state leases. Davis thinks that there might be 7.5 trillion cubic feet of natural gas and 1.7 billion barrels of oil in the prospect, although the state has classified the prospect as "highly speculative."

In early 2006 Escopeta secured the use of a jack-up rig and subsequently obtained an unprecedented waiver to the Jones Act to enable the company to bring the rig to the Cook Inlet from the Gulf of Mexico on a foreign flagged vessel. The company subsequently ran into problems getting the rig north and postponed its drilling plans.

Subsequently California-based Pacific Energy Resources, having obtained the Corsair unit as part of its purchase of Forest Oil's Cook Inlet properties in 2007, determined that it would try to bring a jack-up to the inlet for the open-water season of 2008, to conduct a drilling program in conjunction with Escopeta and Renaissance Alaska, the company that by this time had become operator of the leases at Northern Lights.

But all came to naught.

Pacific Energy did not succeed in bringing the jack-up to the inlet. In March 2009 the company filed for bankruptcy protection and by the summer of 2009 was disposing of its Cook Inlet assets through a Delaware bankruptcy court.

Meantime, frustrated by the lack of progress toward offshore drilling but anxious to encourage exploration of the offshore prospects, Alaska's Division of Oil and Gas was engineering a deal in which existing units and leases at Northern Lights, Corsair and Kitchen would be combined into an expanded single unit called "Kitchen Lights," with Escopeta as operator. Escopeta had farmed in Corsair from Pacific Energy, and Northern Lights from Renaissance and Rutter and Wilbanks.

Under the Kitchen Lights plan of exploration, Escopeta must have a jack-up rig en route to the Cook Inlet by June 20, 2010, with a Kitchen or East Kitchen well spudded by the end of that year. Further wells are required in subsequent years.

Texas-based Renaissance Alaska LLC transferred its Northern Lights leases to Escopeta as part of the deal to form the Kitchen Lights unit. But Renaissance also holds 10,008 acres in state Cook Inlet offshore leases that cover the company's North Middle Ground Shoal and Northwest Cook Inlet prospects, as well as 47,582 acres on the Kenai Peninsula on its onshore North Sterling and West Eagle prospects. The plan is to drill the offshore prospects if Escopeta brings a jack-up rig to Cook Inlet, Mark Landt, Renaissance vice president for land and administration, told Petroleum News Oct. 6.

Renaissance is in the process of transferring its Cook Inlet basin leases to Stellar Oil & Gas LLC, a separate company owned by Renaissance executives Mark Landt, James Watt, Alan Huckabay and Vijay Bangia, Landt said. Stellar Oil & Gas is seeking new funding for its Cook Inlet exploration activities.

News flash: Just prior to going to press in late October, Davis said he was optimistic about having a jack-up in Cook Inlet by spring 2010.

Most exploration in upper Cook Inlet Tertiary

THERE ARE TWO MAJOR SEQUENCES of hydrocarbon-bearing rocks in the Cook Inlet basin: a younger and shallower sequence that is Tertiary in age, and an older and often deeper sequence that is Mesozoic in age. And the basin is generally divided into two major regions: the upper Cook Inlet basin north of the southern end of the Kenai Peninsula and the lower Cook Inlet basin extending southwest from the southern limit of the upper basin.

The upper Cook Inlet basin has been the prime focus of oil and gas exploration and is the only part of the basin with producing oil and gas fields.

This part of the basin attains its greatest depth near the northwest corner of the Kenai Peninsula. In that area about 25,000 feet of Tertiary, coal-bearing, terrestrial sediments overlie a thick sequence of marine Mesozoic sediments. The rocks include an abundance of hydrocarbon sources, reservoirs and traps.

continued on next page

COOK INLET *continued from page 71*

A broadly similar sequence of Tertiary rocks extends across the whole upper Cook Inlet area, but thins toward the edges of the basin and toward the lower basin.

Oil exploration in the area initially targeted the Mesozoic strata but the 1957 discovery of the Swanson River oil field in Tertiary sediments shifted the attention of subsequent exploration to the Tertiary. To date there have been 11 significant oil finds and 28 significant gas finds in the upper Cook Inlet area, with all of the finds occurring in the Tertiary — all of the oil and gas produced in Southcentral Alaska comes from these fields.

And because the geologic stresses that have operated during the evolution of the basin have tended to fold and fracture the rock strata along a northeast-to-southwest trend, the oil and gas fields in the basin tend to line up along that trend, following the crests of large geologic structures.

The largest oil field in the upper Cook Inlet, the McArthur River field, had produced 624 million barrels of oil by the end of 2006, with ultimate recoverable oil reserves of about 646 million barrels, according to data published by Alaska's Division of Oil and Gas. The largest gas field, the Kenai field, had produced 2.314 trillion cubic feet of gas with ultimate recoverable reserves of about 2.458 tcf.

Although the reservoirs of the Cook Inlet oil and gas fields lie within Tertiary rocks, petroleum geologists have determined that the oil actually originated from source rocks in the Mesozoic, in what geologists refer to as the middle Jurassic. On the other hand, although some gas would have been generated by thermal processes from Jurassic source rocks along with the oil, most of the gas originated by itself from bacterial processes in coal-rich Tertiary sediments.

Cook Inlet exploration has mainly targeted large structures in the Tertiary, and some undiscovered oil accumulations probably remain in this type of setting. However, some geologists believe that substantial quantities of oil lie within Mesozoic reservoirs. But, given the expense and relative risk of deep drilling, very few wells have targeted this Mesozoic play.

A 2004 study by the U.S. Department of Energy has also pointed out that the exploration of large oil-bearing structural traps has probably left undiscovered many gas accumulations in the Cook Inlet basin. From a statistical analysis of the known gas accumulations, DOE has estimated that there may be as much as 10 tcf to 14 tcf of undiscovered natural gas in the Tertiary of the upper Cook Inlet area. DOE believes that much of this undiscovered gas lies in the stratigraphic and combination traps that people exploring for oil largely ignored.

Focus on subtle gas plays

With the exception of some undeveloped offshore prospects, exploration for new hydrocarbon accumulations has tended to move away from the big structures, many of which have been drilled and produced. Attention is now starting to focus on subtle, off-structure plays that may contain some of the huge quantities of Tertiary gas thought to still exist in the Cook Inlet basin.

The poor quality of the seismic data for the Cook Inlet area has become an issue when searching for these subtle stratigraphic plays. The thick Tertiary section contains many coal seams and exhibits big density contrasts. This type of geology dissipates seismic energy and gives poor seismic reflections. It has even proven difficult to apply modern 3-D seismic techniques for delineating stratigraphic traps.

Considerable effort is now going into gaining a better understanding of how best to use 3-D techniques in the Cook Inlet geological situation, especially in the deeper parts of the section. And Alaska's Division of Geological and Geophysical Surveys is engaged in a multiyear Cook Inlet basin research project, with the geology of stratigraphic traps as a major focus.

The difficulty in interpreting seismic data, the need to search for subtle traps and uncertainties about the lateral continuity of subsurface rock strata make the Cook Inlet a challenging area to explore — problems with reserve estimation in the Redoubt Shoal field have illustrated some of the risks in reservoir assessment with less than complete subsurface information.

In addition, onshore land access can prove complex because of a multiplicity of land ownership arrangements. However, companies are managing to handle the complexities of dealing with geology that doesn't always line up with land ownership boundaries.

The Susitna basin

Much of the broad area of lowland stretching north from the northeast end of Cook Inlet and crossed by the Susitna River and its various tributaries, as well as by lesser waterways, lies over another basin, referred to by geologists as the Susitna basin and forming what some consider to be a northern extension of the Cook Inlet basin. A major geologic fault, the same fault that delineates the northwest side of the Cook Inlet basin, divides the two basins.

Tertiary rocks, many corresponding to similar rocks in the Cook Inlet basin, occupy the Susitna basin, but the oil-prone Mesozoic source rocks of the Cook Inlet basin have not been found in wells or outcrops in the Susitna Valley.

Seismic data from the Susitna basin have revealed geologic structures dominated by faulting rather than folding, where vertical displacements of blocks of the older rocks that underlie the basin have dislocated the younger Tertiary rocks above.

Nine oil and gas exploration wells and four core holes have been drilled in the Susitna basin. All exploration wells were plugged and abandoned as dry holes, though some did have minor gas shows. The two wells drilled near the deepest part of the basin were the Union Texas Pure Kahiltna Unit No. 1, completed in March 1964 to a total depth of 7,265 feet, and the Unocal Trail Ridge Unit No. 1, completed in October 1980 to 13,708 feet. Coal beds become prominent in the lower part of both of these wells, suggesting a correlation with the coal-bearing, gas-producing formations in the Cook Inlet basin.

Coalbed methane

The prevalence of coal seams in the Tertiary rocks around the Cook Inlet and Susitna basins gives rise to a major resource potential from coalbed methane.

But exploration for coalbed methane in Southcentral Alaska has proved controversial because of issues surrounding split estate land ownership between the State of Alaska and private landowners, and because of worries by local residents about environmental issues, especially ground-water contamination. However, the increasing demand for new gas sources together with new coalbed methane production technologies involving the use of horizontal drilling, coupled with improved guidelines for coalbed methane exploration and development, may lead to successful commercialization of this resource.

Cook Inlet region offers opportunity and challenge

NEARLY ALL OF THE OPERATING oil and gas fields in Cook Inlet derive from exploration done in the 1950s and 1960s, before the discovery of the giant Prudhoe Bay field caused the attention of explorers to switch to the North Slope. As a consequence, only limited exploration of Cook Inlet has taken place in more recent decades.

Although past exploration in the region focused primarily on finding oil, large volumes of gas were also encountered during that drilling effort. A resulting excess supply of stranded natural gas drove the construction of LNG and fertilizer plants at Nikiski on the Kenai Peninsula and has enabled the residents of highly populated Southcentral Alaska to enjoy cheap gas for heating and electricity generation.

In recent years, as production from old oil and gas fields has declined, demand for gas has started to come into balance with supply, while the price of gas in Southcentral Alaska has begun to rise, thus heightening new interest in gas exploration in the Cook Inlet basin.

In 2008 the U.S. Department of Energy granted a two-year extension to the export license for the LNG plant from 2009 to 2011. And the owners of the LNG facility (Marathon and ConocoPhillips) agreed to do some new Cook Inlet gas exploration drilling as part of a deal with the State of Alaska that ensured state support for the license extension.

On the other hand, Agrium, the owner of the Nikiski fertilizer plant, closed the plant in 2007 because of a lack of adequate gas supplies at viable prices. Agrium investigated coal as an alternative feedstock to natural gas for fertilizer production, but said in March 2008 it had determined that its proposed coal gasification facility to supply syngas for the plant was not economic. However, new gas discoveries in Southcentral Alaska or gas from a possible future gas pipeline carrying North Slope gas to the Kenai Peninsula might result in the fertilizer plant being reopened, Agrium has said.

Industrial underpinning

Industrial facilities such as the Nikiski LNG plant underpin the Cook Inlet gas industry by providing a large and relatively stable market for the gas. And, as part of the state's deal with the LNG plant owners at the time of the LNG export license renewal, the owners agreed to allow gas producers other than themselves to supply some of the gas used by the plant.

Local gas and power utilities are the other main purchasers of Cook Inlet natural gas. But these utilities constitute quite a small market, with a gas demand that fluctuates widely between warm summer days when gas usage is relatively low, to frigid winter conditions when gas usage, especially for space heating, is very high.

The LNG plant provides an invaluable service by curtailing liquefaction of export gas during severe winter cold, to enable gas producers to meet the exceptionally high gas deliverability requirements of the utilities. And, also to bolster winter gas deliverability, Marathon and Chevron operate gas storage facilities that use depleted gas reservoirs to store excess gas produced in the summer for later use during the winter.

Alaska's Division of Oil and Gas has held discussions with some companies about the possible establishment of additional storage facilities. The division would like to see these facilities offer storage services to third-party companies, thus making the Cook Inlet gas market more flexible and perhaps creating new opportunities for the sale of gas by independent producers.

Gas badly needed

And new natural gas production from Cook Inlet is badly needed, given the dependence of Southcentral Alaska residents and businesses on gas for heating and power. Despite assuming the cessation of exports from the LNG plant after 2011 and despite also assuming the continued development of existing gas fields, projections of total Cook Inlet gas production show a shortfall relative to utility demand after 2019, Kevin Banks, director of Alaska's Division of Oil and Gas, told the Alaska House Special Committee on Energy in March 2009.

Winter gas deliverability has become especially tight: On Jan. 3, 2009, Enstar Natural Gas Co, the main Southcentral Alaska gas utility, hit a peak daily throughput of 314.5 million cubic feet, causing the LNG plant to reduce its daily gas consumption to just 40 million cubic feet, a volume that Enstar said was close to the lower limit for the plant.

But some significant market challenges face an explorer wishing to find and produce new Cook Inlet natural gas reserves.

In the first place, with virtually all existing utility gas supplies tied up in medium- and long-term contracts between the utilities and a relatively small number of established gas producers, it is very difficult for a new market entrant to find a sufficient market to render a new gas field viable. There is no effective spot market for gas in Southcentral Alaska.

And then, in the absence of a spot market, there is the tricky question of pricing the gas. Because the gas price forms the domi-

continued on next page

COOK INLET *continued from page 73*

nant component of the price that Southcentral Alaska consumers pay for energy, and because regulated utilities supply that energy, the Regulatory Commission of Alaska, the state's regulating agency, in effect regulates Cook Inlet basin utility gas prices. A series of challenges to pricing in new utility gas supply contracts in recent year resulted in what one RCA commissioner has characterized as "the Cook Inlet Gas War."

However, the August approval of a supply contract between ConocoPhillips and power utility Chugach Electric Association, with gas prices indexed to a basket of prices from gas producing areas in the Lower 48, may provide a precedent for the approval of future utility contracts.

Geology of Cook Inlet region

THE SURFACE TOPOGRAPHY OF VOLCANOES, mountain ranges, flatlands and sea passages around the Cook Inlet area provides dramatic evidence of the way in which major pieces of the Earth's crust, known as plates, move around the Earth's surface, tossing up mountain ranges in places and dragging down deep basins in others.

One of the plates, the Pacific plate, slides north along the California and Pacific Northwest coastlines before slipping beneath another plate, known as the North American plate, along a zone marked by the Aleutian trench, south and east of Kodiak Island and the Alaska Peninsula. The massive forces unleashed by this titanic struggle between two of the larger pieces of the Earth's crust have uplifted a chain of coastal mountain ranges, including the Chugach and Kenai mountains, while heat generated deep underground has caused lava and ash to spew up through an arc of volcanoes, known as the Aleutian archipelago. And as the Pacific plate has slid downward beneath the Earth's surface it has dragged down an elongated section of the North American plate to form the Cook Inlet basin.

Two rock sequences

There are two major sequences of hydrocarbon-bearing rocks in the basin.

The events that led to the formation of the first of these sequences began around 350 million years ago, when a volcanic arc in the general vicinity of the present-day Alaska Range poured lava and volcanic materials into adjacent areas. Then, around 240 million years ago, uplift of the area occupied by the volcanic arc started tipping sediments south into a marine basin in the area of the current Cook Inlet. As this basin slowly subsided beneath an ancient sea, many thousands of feet of stratified marine sediments, some rich in organic material, accumulated.

These older and deeper strata of the Cook Inlet basin are referred to as the Mesozoic.

Uplift of the land around 70 million years ago started to form the Kenai and Chugach mountain ranges. Erosion of the mountains then dumped sediments into a Cook Inlet basin that was by then above sea level. Deposition of river-borne sand and gravel alternated with luxuriant swamp vegetation growth. Through this repetitive cycle of vegetative growth and sediment deposition, peat layers were developed and buried, producing present-day coal formations. The nonmarine sands and gravels would later become oil and gas reservoirs in what is referred to as the Tertiary section.

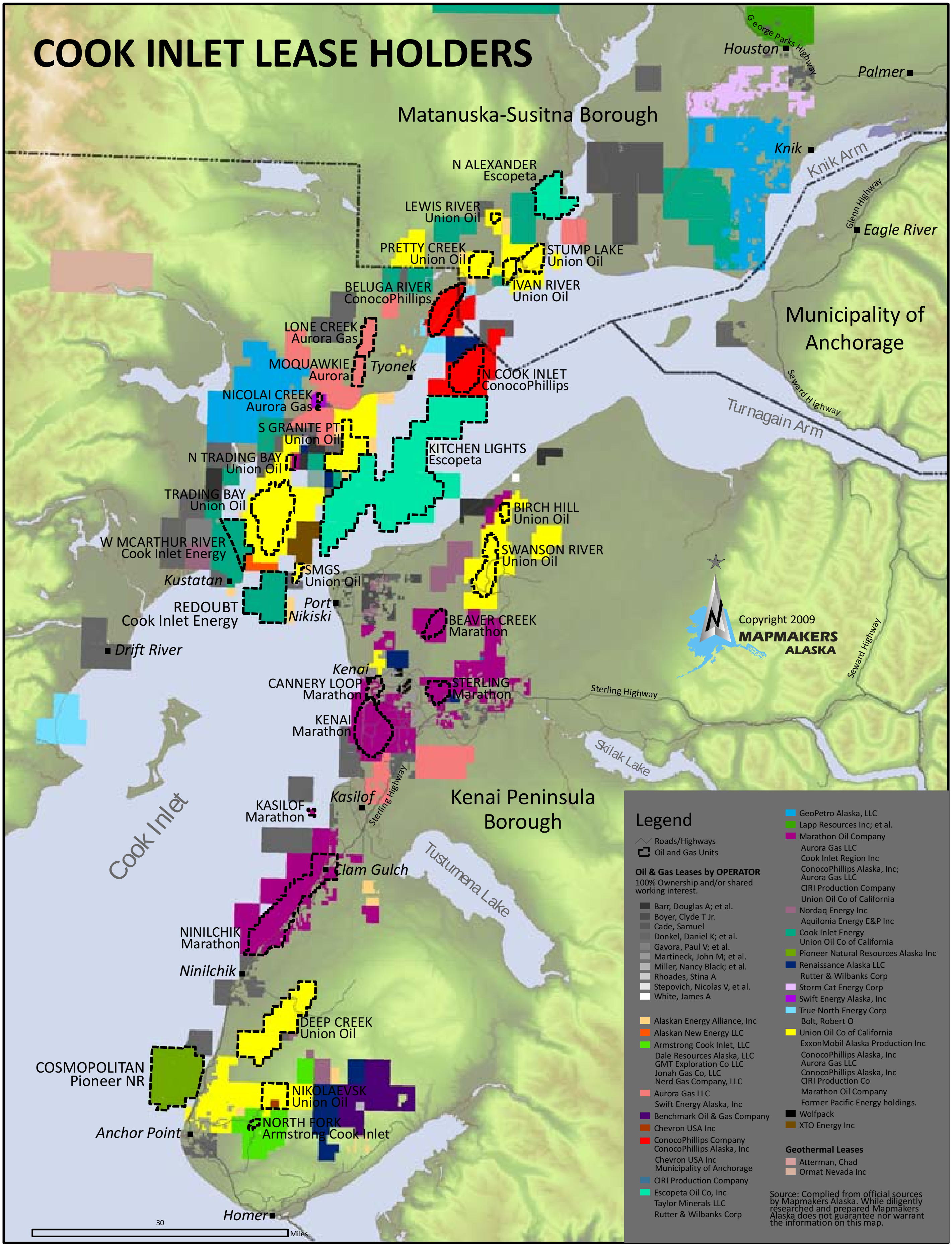
Uplift, accompanied by deformation and fracturing of the rocks, continues today, thus making the Cook Inlet a seismically active region. As a result of a massive earthquake in March 1964, most of the western Gulf of Alaska including Prince William Sound was uplifted while the entire Cook Inlet basin from the Talkeetna Mountains to Kodiak Island sank. Areas of active volcanism still exist and are considered to have high geothermal potential.

Fault bounded

The present day Cook Inlet basin sits between two northeast-southwest trending geologic faults that form massive fractures in the Earth's crust, where the rock strata inside the basin have sunk and tipped inward. One fault runs along the northwest side of the Kenai Mountains, while the other fault runs parallel to the northern Cook Inlet shoreline a few miles onshore.

An area of uplifted rock known as the Augustine-Seldovia arch, under Cook Inlet west of the southern tip of the Kenai Peninsula, divides the upper Cook Inlet basin from the lower Cook Inlet basin. The Mesozoic section contains oil-prone source rocks, including known oil sources in what geologists refer to as the middle Jurassic Tuxedni Group. The Tertiary section contains abundant coal seams and other organic-rich sediments that form a source gas formed by bacterial action, rather like methane bubbling from a dung heap.

Both the Mesozoic and the Tertiary contain potential oil and gas reservoir rocks, although in the Mesozoic strata rock compaction combined with various forms of chemical and thermal alteration may have degraded the reservoir quality. Many sands in the Tertiary strata have excellent reservoir characteristics, although the way in which these sands were deposited from rivers and lakes has tended to result in reservoirs divided into many thin, lens-shaped compartments. ■


COOK INLET LEASE HOLDERS
Houston
George Parks Highway
Palmer
Matanuska-Susitna Borough
Knik
Knik Arm
Glenn Highway
Eagle River
N ALEXANDER
Escopeta
LEWIS RIVER
Union Oil
PRETTY CREEK
Union Oil
STUMP LAKE
Union Oil
IVAN RIVER
Union Oil
BELUGA RIVER
ConocoPhillips
LONE CREEK
Aurora Gas
Municipality of Anchorage
MOQUAWKIE
Aurora
Tyonek
N COOK INLET
ConocoPhillips
NICOLAI CREEK
Aurora Gas
Seward Highway
Turnagain Arm
S GRANITE PT
Union Oil
KITCHEN LIGHTS
Escopeta
N TRADING BAY
Union Oil
TRADING BAY
Union Oil
BIRCH HILL
Union Oil
W MCARTHUR RIVER
Cook Inlet Energy
SWANSON RIVER
Union Oil
Kustatan
SMGS
Union Oil
REDOUBT
Cook Inlet Energy
Port
Nikiski
BEAVER CREEK
Marathon
Copyright 2009
MAPMAKERS
ALASKA
Seward Highway
Drift River
Kenai
CANNERY LOOP
Marathon
STERLING
Marathon
Sterling Highway
KENAI
Marathon
Skilak Lake
Kasilof
KASILOF
Marathon
Sterling Highway
Kenai Peninsula
Borough
Cook Inlet
Tustumena Lake
Clam Gulch
NINILCHIK
Marathon
Ninilchik
DEEP CREEK
Union Oil
COSMOPOLITAN
Pioneer NR
NIKOLAEVSK
Union Oil
NORTH FORK
Armstrong Cook Inlet
Anchor Point
Homer
30
Miles
Legend
Roads/Highways
Oil and Gas Units
Oil & Gas Leases by OPERATOR
100% Ownership and/or shared working interest.
Barr, Douglas A; et al.
Boyer, Clyde T Jr.
Cade, Samuel
Donkel, Daniel K; et al.
Gavora, Paul V; et al.
Martineck, John M; et al.
Miller, Nancy Black; et al.
Rhoades, Stina A
Stepovich, Nicolas V, et al.
White, James A
Alaskan Energy Alliance, Inc
Alaskan New Energy LLC
Armstrong Cook Inlet, LLC
Dale Resources Alaska, LLC
GMT Exploration Co LLC
Jonah Gas Co, LLC
Nerd Gas Company, LLC
Aurora Gas LLC
Swift Energy Alaska, Inc
Benchmark Oil & Gas Company
Chevron USA Inc
ConocoPhillips Company
ConocoPhillips Alaska, Inc
Chevron USA Inc
Municipality of Anchorage
CIRI Production Company
Escopeta Oil Co, Inc
Taylor Minerals LLC
Rutter & Wilbanks Corp
GeoPetro Alaska, LLC
Lapp Resources Inc; et al.
Marathon Oil Company
Aurora Gas LLC
Cook Inlet Region Inc
ConocoPhillips Alaska, Inc;
Aurora Gas LLC
CIRI Production Company
Union Oil Co of California
Nordaq Energy Inc
Aquilonia Energy E&P Inc
Cook Inlet Energy
Union Oil Co of California
Pioneer Natural Resources Alaska Inc
Renaissance Alaska LLC
Rutter & Wilbanks Corp
Storm Cat Energy Corp
Swift Energy Alaska, Inc
True North Energy Corp
Bolt, Robert O
Union Oil Co of California
ExxonMobil Alaska Production Inc
ConocoPhillips Alaska, Inc
Aurora Gas LLC
ConocoPhillips Alaska, Inc
CIRI Production Co
Marathon Oil Company
Former Pacific Energy holdings.
Wolfpack
XTO Energy Inc
Geothermal Leases
Atterman, Chad
Ormat Nevada Inc
Source: Complied from official sources by Mapmakers Alaska. While diligently researched and prepared Mapmakers Alaska does not guarantee nor warrant the information on this map.

Alaska is where the oil is

Escopeta sees Cook Inlet as best place to explore for and produce large quantities of oil and gas in U.S.

By Danny Davis

President, Escopeta Oil and Gas

"Why is your company looking for oil and gas in Alaska?" What do you find most attractive about the state, in terms of oil and gas development?

When asked by a reporter why he robbed banks, depression-era gangster John Dillinger famously answered, "Because that's where the money is."

Escopeta Oil and Gas LLC was asked by Big Risks, Bigger Rewards, "Why is your company looking for oil and gas in Alaska?" To paraphrase Dillinger, it would have to be said, "Because that's where the oil is."


DANNY DAVIS

America needs domestic sources of energy. Going forward, Alaska can and will continue to be a major piece to the puzzle of America's energy security.

Alaska today presents an opportunity for small oil companies to grow and prosper.

As the world's largest oil companies now have set their sights on giant prospects in the Arctic seas and in foreign countries, the stage is set for smaller companies to extend the success story of oil and gas exploration and production on state lands in Alaska. Smaller companies have the low overhead and agility to fill in the margins around the major pools of petroleum that have been exploited by the majors. As in other mature oil provinces — Texas, for example — smaller firms will be the future. The investments and ingenuity of these small companies will allow future generations of Alaskans and Americans to benefit from Alaska's oil bounty.

Revitalizing Cook Inlet

Escopeta is a successful exploration and production company based in Houston, Texas. Today Escopeta is the largest unit holder in Alaska's Cook Inlet. Cook Inlet represents to Escopeta a chance to find one of the largest pools of oil and gas in the United States.

Cook Inlet is the birthplace of the modern oil and gas industry in Alaska.

Cook Inlet oil fields have been in production since 1958. Offshore wells have been producing oil and gas since the early 1960s.

Cook Inlet has existing infrastructure, a highly trained and skilled local workforce, and experienced mariners with operating experience and the right watercraft for sailing Cook Inlet's challenging waters.

In Escopeta's opinion, Cook Inlet is the best place to explore for and produce large quantities of oil and gas in the United States.

Benefits to Alaskans

Citizens of Alaska will benefit from the investment by Escopeta and its partners in many ways, over and above the royalty income the state will receive from Escopeta's Cook Inlet production.

Anchorage and other Railbelt cities have been lit and heated for decades with natural gas deposits that were discovered in the '50s and '60s. These fields are now in decline.

When oil was discovered at Prudhoe Bay, many companies abandoned Cook Inlet and followed the oil rush to the North Slope. The pace of exploration in Cook Inlet has slowed to a trickle, and so has the oil output. Escopeta is positioned to reverse this decline.

The Tesoro refinery on the Kenai Peninsula was designed to handle 72,000 barrels a day of sweet Cook Inlet crude. Due to low Cook Inlet crude production, it operates below capacity. It now must import about 30,000 barrels per day from foreign sources. The Nikiski refinery provides roughly 70 percent of Alaska's motor fuel, and 40 percent of jet fuel to Anchorage's international airport.

It is ironic, and little known, that most Alaskans are burning gasoline refined from imported oil in their cars every day.

New crude output from Escopeta's offshore production platforms would actually reduce environmental hazards to the productive fisheries of Cook Inlet by reducing tanker traffic. Imported oil is transported to Cook Inlet in single-hull foreign-flagged tankers. Tankers also carry away heavy residues from North Slope oil, which the Nikiski plant was not designed to refine.

Likewise, natural gas output is in serious decline. According to Enstar, gas output will plummet steeply in just a few years, with major shortages occurring as early as 2011. Using even the most optimistic of projections, North Slope gas will not reach the area in time to avert a severe shortage.

These looming shortages have national security implications as well. Anchorage's military installations are dependent upon Cook Inlet natural gas for heat and electricity.

All parties will benefit from the low cost of transportation involved with serving the local market, while consumers will see lower prices and increased energy security once oil and gas begin to flow from new Cook Inlet production platforms of Escopeta and its partners.

Cook Inlet opportunity

Fortunately the story of the Cook Inlet oil fields is far from over. The U.S. Department of Energy said in a 2004 report that according to their research, only 5 percent of the potential oil and gas reserves in Cook Inlet have been found.

So a bright future is possible, but only with oil company investment and regulatory cooperation from the State of Alaska.

Several companies are drilling a few low-cost gas wells in Cook Inlet which may result in a moderate increase in natural gas supplies — but the most promising structures lie offshore in Escopeta's Kitchen Lights unit.

Offshore prospects require the use of a jack-up drilling rig — an expensive proposition that substantially increases the financial risk of exploration.

Escopeta and its partners are working hard to overcome the financial hurdles so that the jobs and economic stimulus of a multibillion-dollar exploration and production effort can accrue to the citizens of Alaska, while Alaska energy is delivered to the citizens of the United States.

Fortunately, the state has said it wants to level the playing field to allow smaller oil and gas companies to explore and thrive all over Alaska.

As Revenue Commissioner Pat Galvin told Petroleum News in December: "We've got companies that have never been on the North Slope drilling wells." As is typical of mature oil provinces that lose the interest of the majors, smaller companies move in, he said.

The state has set the stage for profitability with its Alaska's Clear and Equitable Share tax structure, discovery royalty program, and with the cooperation and assistance it has provided to Escopeta and other independents.

Smaller companies have economies of scale that will allow them to profitably find and develop smaller fields that just don't pencil out for the majors.

As the state, small energy companies, and the people of Alaska continue to work together, the future will be bright. ■

Advertiser Index

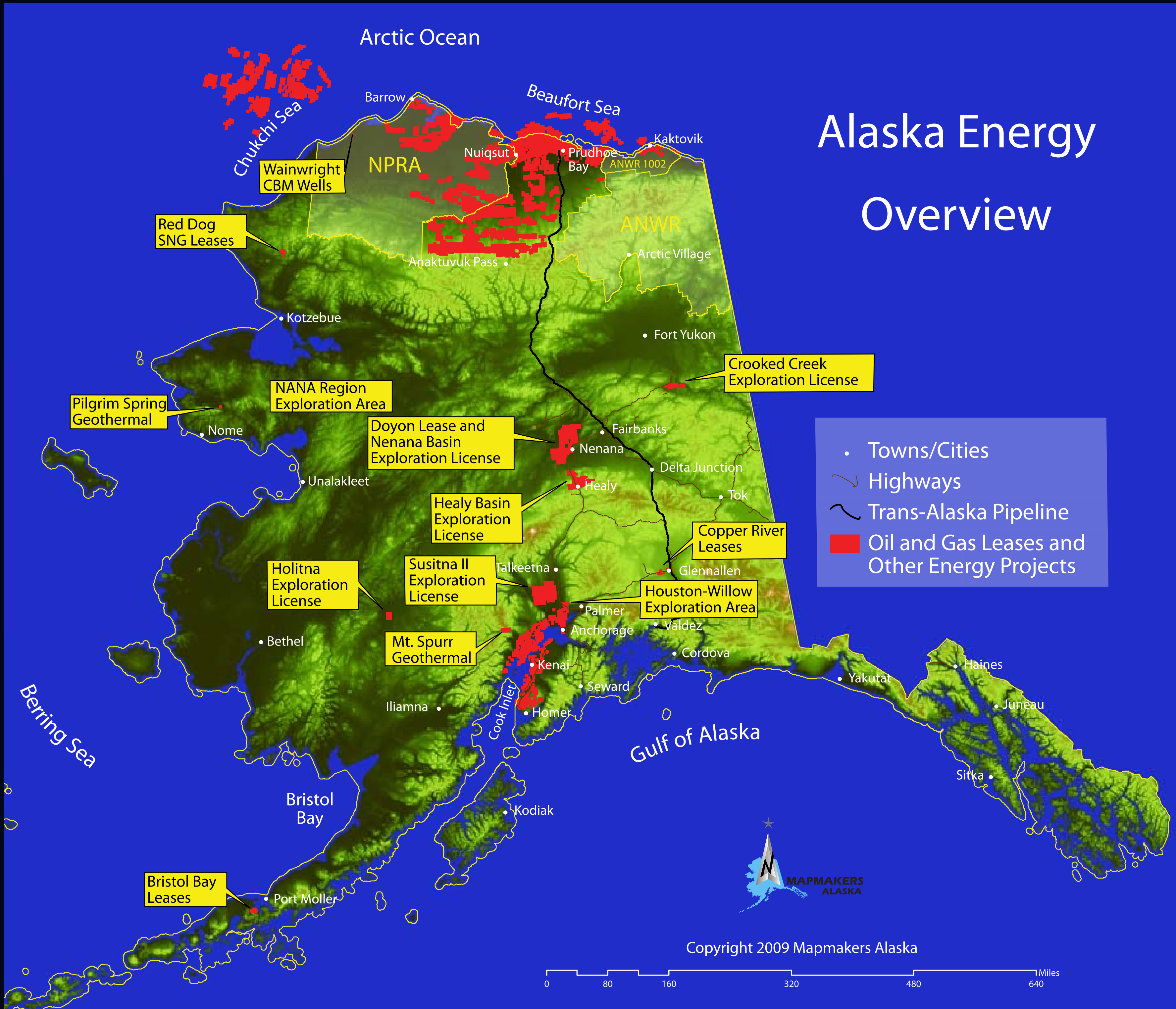
A

B-F

G-M

N-P

Q-Z


Alaska Energy Overview
Arctic Ocean
Beaufort Sea
Chukchi Sea
Bering Sea
Gulf of Alaska
Bristol Bay
Cook Inlet
NPRA
ANWR
ANWR 1002
Barrow
Nuiqsut
Prudhoe Bay
Kaktovik
Anaktuvuk Pass
Arctic Village
Kotzebue
Fort Yukon
Nome
Unalakleet
Fairbanks
Nenana
Delta Junction
Healy
Tok
Glennallen
Talkeetna
Palmer
Anchorage
Valdez
Cordova
Bethel
Kenai
Seward
Iliamna
Homer
Kodiak
Port Moller
Yakutat
Haines
Juneau
Sitka
Wainwright CBM Wells
Red Dog SNG Leases
Pilgrim Spring Geothermal
NANA Region Exploration Area
Doyon Lease and Nenana Basin Exploration License
Healy Basin Exploration License
Crooked Creek Exploration License
Copper River Leases
Houston-Willow Exploration Area
Susitna II Exploration License
Holitna Exploration License
Mt. Spurr Geothermal
Bristol Bay Leases
Towns/Cities
Highways
Trans-Alaska Pipeline
Oil and Gas Leases and Other Energy Projects
MAPMAKERS ALASKA
Copyright 2009 Mapmakers Alaska
0
80
160
320
480
640
Miles