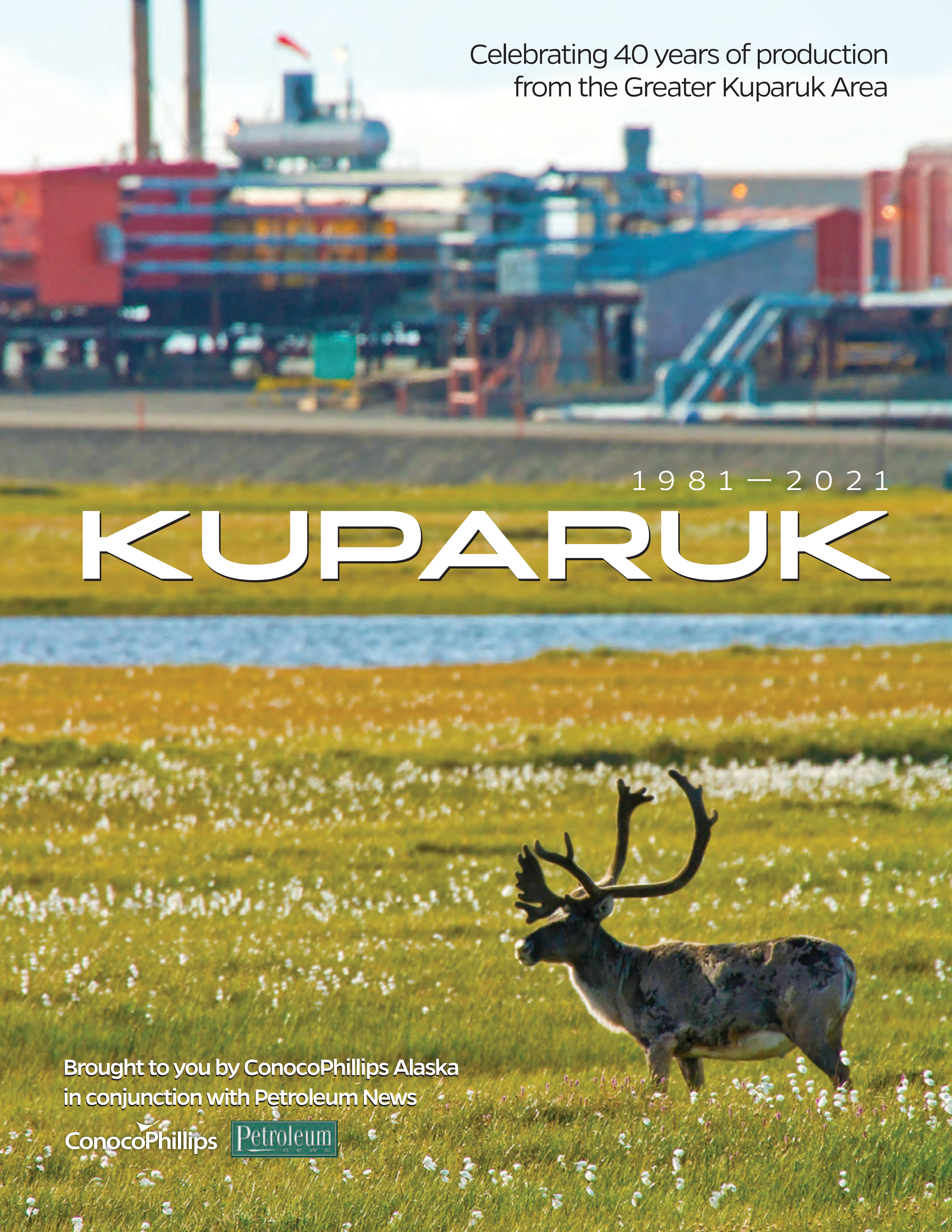

Celebrating 40 years of production from the Greater Kuparuk Area

1981 — 2021

KUPARUK

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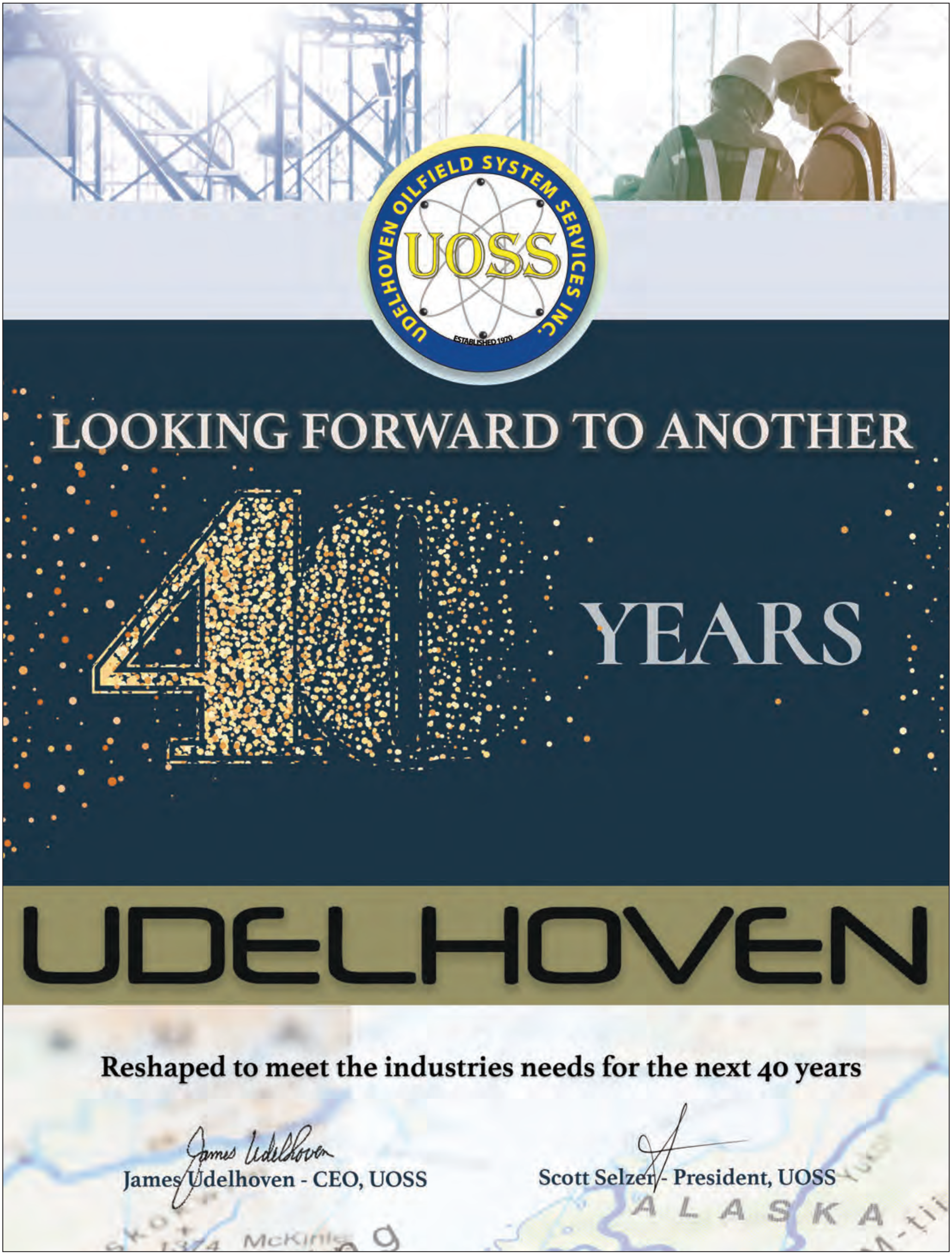
ConocoPhillips Petroleum News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1990S IN THE GREATER KUPARUK AREA

ConocoPhillips

KUPARUK

Released March 2022

Brought to you by ConocoPhillips Alaska in conjunction with Petroleum News

Petroleum News Staff

KAY CASHMAN
Executive Publisher & Founder

KRISTEN NELSON
Editor-in-Chief

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Production Director

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Special Publications Director

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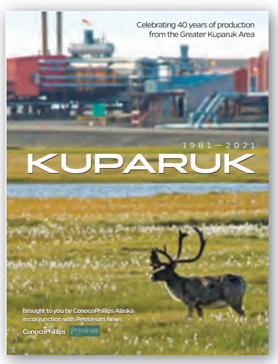
Bookkeeper



MAILING ADDRESS:
PO Box 231647
Anchorage, AK 99523-1647

(907) 522-9469
circulation@PetroleumNews.com
www.PetroleumNews.com

To order additional copies, contact Heather Yates at hyates@petroleumnews.com

Cover photo: A caribou stands in front of Drillsite 1D, Kuparuk in 2008. ConocoPhillips has been monitoring caribou movement and distribution in the Kuparuk area since the late 1970s. Caribou are often present in the Kuparuk field.

Chris Arend, Photographer

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FIRST DECADE OF THE 21ST CENTURY IN GKA

2010 THROUGH MID-DECEMBER 2021 IN GKA

ADVERTISER INDEX

Welcome from Erec Isaacson, president of ConocoPhillips Alaska

December 2021 marked the proud 40th anniversary of the Kuparuk oil field, a significant event in the history of not only ConocoPhillips but also the State of Alaska and the U.S. oil industry.

EREC ISAACSON

On Dec. 13, 1981, ARCO Alaska announced first production from Kuparuk, which at the time was the second largest U.S. oil field, trailing only its neighbor Prudhoe Bay to the east. Initial expectations for the field were high, but through the years Kuparuk far exceeded all of them, thanks to the work and innovation of generations of ConocoPhillips Alaska employees.

Kuparuk and its satellites have yielded more than 2.5 billion barrels of oil recovered to date with still more production expected over the decades ahead. Average production in December 2021 was 85,000 barrels per day, compared to a peak of 340,000 barrels per day in December 1992 following natural decline. There are over 500 producing wells in the Greater Kuparuk Area and 8 different recognized reservoir intervals. Even after all these years, Kuparuk remains among a small handful of the largest U.S. conventional oil fields. ConocoPhillips proudly serves as Kuparuk's operator with 94.5% working interest.

The success at Kuparuk is largely due to the team's dedication to finding innovative solutions and modeling environmental stewardship practices, which have and will continue to serve as the foundation for responsible resource development on Alaska's North Slope.

Over the years, the Kuparuk River Unit has been recognized with the Environmental Protection Agency Award for Pollution Prevention (the first time the prestigious award was given to an Alaska company), the Interstate Oil and Gas Compact Commission Environmental Stewardship award and is a proud member of the Alaska Green Star program. Environmental consciousness is part of daily life at Kuparuk,

Kuparuk and its satellites have yielded more than 2.5 billion barrels of oil recovered to date with still more production expected over the decades ahead.

and efforts have grown to include ConocoPhillips' support of conservation and access programs supporting key fish and wildlife habitats.

Kuparuk's processing, pipeline and transportation infrastructure enabled further westward development, including discoveries of four Kuparuk satellites, then our Alpine and Greater Mooses Tooth fields, and more recently the Willow and West Willow finds. Today, more exploratory prospects even farther west await future exploration. The implementation of technology, such as coiled tubing and extended reach drilling, allows for development to avoid or minimize impacts to the environment. We are always seeking new and better ways to responsibly deliver Alaska's energy potential.

Our people are at the heart of the 40-year success at Kuparuk. Each year, the field generates thousands of Alaska jobs and millions in state revenues, which benefit every Alaskan and support the communities where we live.

I'm proud to work alongside the many individuals who take their commitment to safe, reliable operations to heart, and who continue their dedication outside of work to support organizations across our state with their time and energy.

I would like to extend my sincere appreciation to the employees of the Alaska business unit — past and present — for their impressive and ongoing record of success with the Kuparuk Field.

Layer upon layer of improvements, rejuvenation at Greater Kuparuk Area

ConocoPhillips Alaska's North Slope development, operations VPs Bruner and Kuzyk talk about what, who made Kuparuk a success

By KAY CASHMAN
Petroleum News

In early December 2021, Lisa Bruner, then-ConocoPhillips Alaska vice president, North Slope development, and Bruce Kuzyk, ConocoPhillips Alaska vice president, North Slope operations, were interviewed by Petroleum News for this magazine. Below are PN's queries and Bruner and Kuzyk's answers.

Q. *Please address technical innovation at Kuparuk over the last 10 years.*

A. There are three different themes of what we've seen over the last decade. First and foremost I will point to improved drilling technology … in particular our technology around horizontal drilling. What we're trying to do with horizontal drilling is … contact more reservoir footage from a single well and that leads to a smaller footprint for each barrel of oil produced.

So we're continuing to push the envelope on how far we can drill in a given well. The longer we can drill … the fewer number of wells we need in total to recover the resource.

Q. *Please give us some examples.*

A. Lisa: In 2018 we drilled one of our West Sak reservoirs called 1H NEWS. We only had four producers in that particular development but we drilled a total of 127,936 feet, or 24 miles, of total lateral footage in four wells. We had low trouble time and really high efficiency so in terms of the number of days per foot drilled we made really significant progress. I would say with that development we pushed the boundaries of how much reservoir can be contacted with a single multilateral well.

Then we started to drill the Torok reservoir at Drill Site 3S, one of our drill sites in Kuparuk, and we drilled a well pair in 2015-2016 and contacted over 4,000 feet of reservoir in a single lateral. Now we are about to drill another well pair where we will contact about 12,000 feet of reservoir from a lateral, so a 300% increase from well pair to well pair as we develop the reservoir. We're continuing to look for opportunities to push those lateral lengths even farther as we continue to develop the field.

Q. *I assume this is one of the main things you're doing to reduce the environmental footprint.*

A. Lisa: Yes, it is. The other thing we're doing is leveraging our existing infrastructure. That's another way to really minimize our environmental footprint. We're continuing to find and develop resources under current, existing pads that are already sitting there.

CONOCOPHILLIPS ALASKA

Bruce Kuzyk and Lisa Bruner.

I mentioned the Torok reservoir, which we are drilling from Drill Site-3S — that's really a great example of maximizing the existing infrastructure. We're re-drilling in existing well slots.

Drilling more distance from existing infrastructure — that's what we're able to achieve from these successful drilling campaigns. It doesn't require additional surface infrastructure to reach it. It's a great way for us to repurpose the existing infrastructure. It's such a mature field that we can start developing some of the more mature areas of the reservoir as technology continues to advance … and still increase the amount of oil that we are developing and producing.

Q. *Bruce, can you share your thoughts on this topic?*

A. Bruce: From an operations perspective, there are a couple key technology areas that I'd like to mention. One of them is on the existing facilities at Kuparuk. Even though those facilities are 40 years old we're making great progress using new technology and innovation. The first one I'd like to mention is data analytics and data visualization tools. It sounds fairly simple, but it's decades of data that we now have the ability to mine and make sense of with visualization tools that help us make better decisions and more timely decisions on how we maintain our equipment.

And so that gives us enhanced predictability on the equipment failure rates, and it improves our facility reliability. It optimizes our maintenance inspection intervals and the ultimate outcome is a reduction of maintenance costs, production losses and facility downtime.

You can also link that with CPF-3, Central Processing Facility-3 — our first pilot that we put Wi-Fi across the entire facility.

We used to have to dig through files, now our operations and maintenance techs have the available information at their fingertips.

The last one I'd like to mention is on our condition-based monitoring

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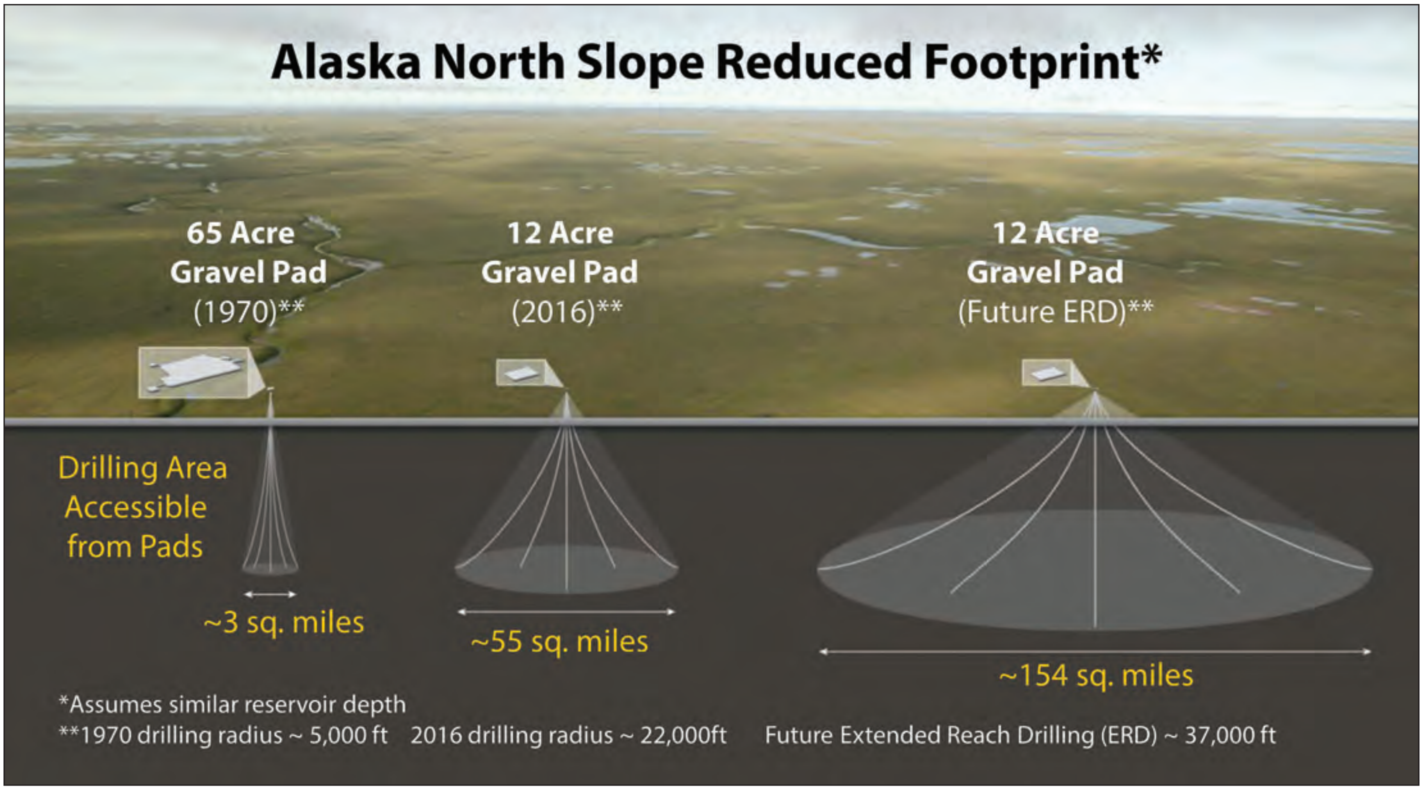


of our critical equipment. Electronic sensing devices used for continuous monitoring of critical equipment help us determine the condition of the equipment and optimize when we would take it down for repair.

Q. *Anything else you would like to say?*

A. Lisa: Going back to your first question around innovation and new technologies, we're using coiled tubing drilling — we call it CTD for short — it has really been a technology that has been significant in a mature reservoir like Kuparuk.

There's still a lot of remaining potential in Kuparuk — we call it bypassed oil — but getting to it is not always easy to do with a rotary rig and so we use coiled tubing because it's more flexible and it allows us to drill multiple lateral sections from a single wellbore, so we can more easily search for bypassed oil and contact it at a relatively low cost.

Q. *What is the primary focus, or goals, at Kuparuk today and is cost-cutting one of them?*

A. Bruce: When we talk about cost-cutting or reducing costs, cost-cutting is generally an outcome of our optimization efforts. So, we're not necessarily looking at cutting costs; we're constantly looking at ways of doing business better and one of the outcomes of that is cost reduction.

We have to evolve to stay competitive. We always have to look at better ways to do things, better ways to work, and how to streamline. We're now competing with the unconventional capabilities down in the Lower 48, so we always have to be competitive.

We have been re-designing our operating philosophy in Kuparuk over the past year. This effort has optimized our operations through the utilization of data analytics, integrated planning, technology and innovation.

We accomplished these improvements by empowering our workforce to drive ownership and commit to strategic direction and that will better position us to capture value.

> *A healthy base attracts development capital. And an attractive development program and good development projects, in turn, feed a healthy base. —Lisa Bruner*

We need to maintain our cost discipline to manage through the fluctuating oil price cycles.

We not only want to survive in the low end of the cycle, we want to thrive.

We're constantly learning, constantly challenging ourselves and stive for continuous improvement.

A. Lisa: If I could add to the competitiveness of the asset, what we are doing year over year with a continuous improvement mindset is keeping our costs as low as possible so that we can continue to attract development capital.

A healthy base attracts development capital. And an attractive development program and good development projects, in turn, feed a healthy base.

Ensuring that the development program is as healthy as it can be keeps the field economic and competitive during the different price cycles.

Q. *Please describe seismic programs done in the last 10-15 years at the Kuparuk River field and its satellites.*

A. Lisa: There have been a number of seismic surveys over the past decade or so, although our focus has been in maximizing value from the existing datasets that we have.

But when we look at the 3-dimensional seismic surveys that have been done in the Kuparuk River unit in 1988, again in 2005, and then in 2011, and then again in 2015, each kind of vintage 3D data that we

acquired was really around leveraging whatever the latest acquisition technology was at the time.

The 2015 survey was part of our agreement to purchase the Nuna discovery from Caelus. It was a high-quality survey that covers the majority of the Torok reservoir accumulation. We're calling it the Nuna development and also covers the Coyote reservoir. Those are two future developments that sit underneath our 3S pad and our 3T pad in the field.

Q. *What's the status right now of Coyote and Nuna?*

A. Lisa: So, Coyote, we are in the process of drilling. We sidetracked an existing well at 3S drill site to test the Coyote prospect on our acreage. We got our well down at the end of 2021 and we should have flow test results around the first quarter of 2022.

Q. *How deep do you have to go to hit the Torok at 3S?*

A. Lisa: About 4,500 feet deep.

Q. *What does the Greater Kuparuk Area mean, as compared, for example, to the Kuparuk River unit?*

A. Bruce: They are essentially the same thing. The Kuparuk River unit, as defined in the Kuparuk River Unit Agreement, contains several participating areas, such as the Kuparuk field, West Sak, Tarn and the other satellites. The Greater Kuparuk Area is the term we use within ConocoPhillips to refer to the Kuparuk field and all the associated satellites.

Q. *Can you address safety in the Greater Kuparuk Area?*

A. Bruce: We're very proud of our safety program, especially how it continues to evolve. We're having a great safety year again and we expect to continue that trend.

We continue to learn and make positive changes to our safety program with new tools.

We recognize the importance of understanding human factors.

Also, I would say we're on the leading edge of ConocoPhillips regarding the utilization of learning teams following an incident or a near miss.

Learning teams are a psychologically safe place to get all the facts on the table and learn from an incident and be able to make adjustments within our operations to avoid a repeat incident.

I think we've leveraged more learning teams in Alaska than anywhere else in ConocoPhillips. We're seeing great value in them. They're a great way to have everybody participate in a no-blame investigation.

We focus on understanding all the hazards around a task and that includes management verification of life-saving rules.

We're having discussions with the workforce, listening to them and making sure that we're giving them all the tools and training that they need to conduct the job safely.

It's interesting that we're in a facility that's 40 years old, and we constantly learn to adapt and evolve as we move forward.

Q. *How many people in a Learning Team?*

A. Bruce: Generally they are around six to 10 people, including subject matter experts, as well as fresh eyes to make sure we are getting diversified perspectives. And we're trying to understand biases within

When we talk about cost-cutting or reducing costs, cost-cutting is generally an outcome of our optimization efforts. So, we're not necessarily looking at cutting costs; we're constantly looking at ways of doing business better and one of the outcomes of that is cost reduction. —Bruce Kuzyk

the discussion to make sure we're digging in and finding out what went wrong. It's trying to understand the human factors as well as the mechanical failures.

When you take the Learning Team approach people feel safer to speak their minds and tell us exactly what we can do better.

Q. *Would you like to say something else?*

A. Bruce: I would just like to add in a closing statement: Here we are 40 years later. So why is Kuparuk successful?

I think it's because we have a world-class workforce. We hire and retain the most talented people in the industry.

Our teams are constantly challenging themselves and are passionate about their work. They care about the success of the company, the industry, and the state. They also care about their community, and support hundreds of organizations across Alaska with their time and resources. They are flexible, they are innovative and very talented.

I'd also like to recognize that we are 40 years into Kuparuk, and the facilities are still in great condition; they still look like they're brand new due to great maintenance and asset integrity. There's so much life left out there, and that is exciting.

Celebrating Kuparuk's 40th anniversary in pictures

On Dec. 13, 2021, the 40th anniversary of oil production from the Kuparuk River field, an 80s Spirit Day photo booth was set up for employees and contractors in the ConocoPhillips Anchorage Tower Office complex in downtown Anchorage.

ConocoPhillips' Anchorage employees dressed up in 80's attire on Dec. 14 as part of the anniversary spirit week celebration.

The company's employees on the North Slope also enjoyed special celebration anniversary dinners prepared by Denali Universal Services Catering Team.

PHOTOS COURTESY CONOCOPHILLIPS ALASKA

Top: Back row L to R: Ethan Plunkett, Brad King, Tricia Allwardt, Jenny Jones. Front row L to R: Thomas Neely, Aimee Villarreal.

Donald Allan, Austin Thayer, Vincent Lelarge.

Aimee Villarreal

Lee McAuliffe

A history of environmental stewardship

Interview with Senior Environmental Coordinators of ConocoPhillips Alaska's Environmental Sustainability and Permitting Group

By KAY CASHMAN
Petroleum News

Over the last 40-plus years ConocoPhillips Alaska's North Slope environmental studies have "significantly contributed to the body of Arctic knowledge," Chrissy Pohl said in a Dec. 20 interview with Petroleum News.

Pohl is a Senior Environmental Coordinator with the company's Environmental Sustainability and Permitting Group along with her counterpart Sarah Kenshalo, — Pohl for biological sciences and Kenshalo for physical sciences. Both grew up in Alaska, Pohl in Anchorage and Kenshalo in Palmer. "Alaskans supporting the environment just makes sense, we love this state as much as every Alaskan" Kenshalo stated.

"Sarah is overseeing more of our climate informed work — the physical effects of climate change, hydrology, permafrost, vegetation, soil, water, archaeology — and I focus on biological sciences and wildlife -- primarily fish, caribou, bears, and birds. We also work closely with our Village Outreach group on subsistence monitoring studies," Pohl said.

CONOCOPHILLIPS ALASKA

Sarah Kenshalo and Chrissy Pohl

Working with federal, state and local regulators, as well as local communities, ConocoPhillips environmental group routinely develops and conducts multi-year and baseline monitoring programs across the North Slope including:

•Annual hydrological surveys within important watersheds such as the Colville River Delta;

• Lake surveys to document water quality and quantity and usage by various fish species;

• Stream surveys to document the distribution and abundance of fish species;

• Archaeological surveys to ensure avoidance of culturally significant sites or artifacts;

• Annual wildlife surveys and analysis to document the distribution and abundance of terrestrial mammals and avian species;

• Polar bear maternal den surveys; and

• Vegetation mapping surveys to understand how key wildlife species use certain habitats.

Develop and maintain Arctic ops

ConocoPhillips Alaska's Environmental Sustainability and Permitting team consists of a total of 11 individuals.

"Collectively we conducted over 20 formal studies in 2021 alone." Pohl said.

The group's work area covers all of northern Alaska at and near where the company transports, produces, explores for, and develops oil and gas fields.

While most of the 2021 studies were conducted west of the Greater Kuparuk Area near ConocoPhillips' newer producing fields and where the company is exploring and pursuing development, three of the 2021 studies directly involved Kuparuk: aerial infrared surveys of polar bear denning habitat; caribou monitoring; and tundra rehabilitation.

"There's a long history of environmental studies on the North Slope. Last week one of our counterparts sent us a picture from an old Petroleum News article. It was of a rig in the 1980s first coming into the Kuparuk field and the highlight was that the placement of the pad was to avoid waterfowl habitat," Pohl said.

"It's nice to know that environmental stewardship was considered and prioritized in early oilfield development, and it has continued to advance as the science has improved, minimizing environmental impact on the North Slope."

"There's been a lot of learnings and best practices developed over the last 40 years," Kenshalo added. "And that continues to inform how we develop and maintain our Arctic operations going forward."

"On the physical sciences side especially, the data gathered by our teams of scientists in the field is directly informing the engineering and maintenance of new and existing facilities. I work closely with the engineering teams on ice road routing, stream crossings, erosion potential, surface stability, things like that."

Deep gravel mine sites

Probably one of the biggest ongoing successes of the group and the collective efforts of the North Slope operators is the story of the gravel mine site reclamation. Oil industry and regulators joined forces to convert the former gravel mine into fish and waterfowl habitat— habitat that is also used by mammals.

"The North Slope is a vast wetland that overlays permafrost. Gravel is required for roads and pads to provide a stable driving surface and to keep the underlying permafrost frozen. So, local gravel mines (or 'borrow pits') are developed" Kenshalo said.

ConocoPhillips Alaska and its predecessor ARCO began developing deep gravel mines in the late 1970s as an alternative to taking gravel and water directly from riverbeds, which was the standard of the time.

Once the gravel resource was extracted, the area would undergo reclamation to return the area to functioning habitat; contributing to the overall ecosystem. As part of the reclamation progress, the company started letting the gravel mines naturally flood to create deep over-wintering fish habitat. Later, gravel mine sites were selected to be near streams, to promote eventual flooding, fish habitat, and provide the fish with vital movement pathways. This was done in collaboration, and with approval from, the Alaska Department of Fish and Game and Alaska Department of Natural Resources.

"Many of the lakes on the North Slope are quite shallow and freeze to the bottom, which means the fish can't reside over the winter. They have to find other places to go — out into deeper river systems or find rare deep lakes where they can overwinter," Kenshalo said.

"We have developed gravel mine sites adjacent to local stream systems to allow for ultimate connection. This allows fish to populate local stream systems that previously had grounded out during the winter, forcing the fish into other territory.

"In Kuparuk in particular, the reclaimed gravel mine sites and their overwintering fish habitat are an example of environmental stewardship that integrated the greater Kuparuk community spirit," she said, turning to Pohl. "Fish & Game and ConocoPhillips partnered for some of the habitat enhancement that occurred," Pohl continued.

"Starting in the late 1980s mine sites were flooded and rehabilitated to specifically provide fish, and later other wildlife, such as nesting shorebirds and grizzly bears, with habitat. Flooded and rehabilitated gravel mine sites were found to provide such a benefit that the program was continued and expanded."

"In the early 1990s Fish & Game stocked grayling in some of the flooded gravel mine sites. These weren't grayling that were raised in a hatchery; they transplanted them from the Kuparuk River and some of the nearby streams.

The hope was that the transplanted fish in the gravel mine sites would become self-sustaining, so that they didn't have to go back and re-stock the flooded sites every year.

"That's exactly what happened with the grayling. There are now big, beautiful grayling through a number of the reclaimed gravel mine sites and associated stream systems. When snow and ice melt away, what we call "open water months" the grayling and other anadromous fish move into the streams and migrate over to other streams for the purposes of breeding and feeding, and then they learn through their generational memory to come back to the mine sites for wintering," Pohl said.

"Previously there weren't fish in the smaller streams that lacked overwintering habitat, and now there are robust, self-sustaining fish populations.

"It was not just grayling, but later different species of native anadromous fish, such as broad and humpback whitefish and least cisco,—started establishing themselves in the flooded mine sites," Pohl said.

"What's remarkable about these fish is that some individuals will actually leave the streams in Kuparuk and go spawn in the Colville River where they are a targeted subsistence species. Unlike salmon, the species live after spawning, so they'll spawn in the Colville or NPRA streams, then return to the mine sites. It takes

CONOCOPHILLIPS ALASKA

Fish biologists use nets to safely capture fish for measurements and to record the species that use the streams and creeks in the Arctic. Fish are returned unharmed to the streams.

them about two years to recover from their effort — and so then they go back again. They are hardy, long-lived subsistence species," Pohl said.

"The result is that there are now established sensitive, or anadromous, fish populations in drainages in Kuparuk including Charlie Creek, Ugnu Creek, and East Creek that previously had none of that overwintering habitat. They were just these nice streams — drainages important to the coastal plain ecosystem but without a sensitive fish species. This has turned into robust self-sustaining fish populations of numerous species across several stream systems," Pohl said.

Not just fish

"Another benefit of the reclaimed mine sites is that they provide a lot of ecosystem services. Gravel mine site reclamation can specifically include upland areas, another rare habitat on the vast, flat tundra. We see caribou using upland areas as a way to get a bit of a breeze and some relief from mosquitos during the insect harassment season. They also draw in different bird species. " Kenshalo said.

"We have evidence of the North Slope grizzly bears using the mine sites for denning. People tend to only think about the polar bears on the North Slope, but there is a robust population of grizzly bears up there as well," Pohl said. They also have evidence of "owls, shorebirds a variety of other avian species, and terrestrial mammals using the mine sites."

Probably one of the biggest ongoing successes of the group and the collective efforts of the North Slope operators is the story of the gravel mine site reclamation.

Caribou monitoring

ConocoPhillips has been monitoring caribou movement and distribution in the Kuparuk area since the late 1970s.

"And if we go back further, into Prudhoe, for many decades collectively," Pohl said, noting that there is a long history of partnership regarding caribou studies.

"For almost all of our environmental monitoring we work through established third-party scientific groups to maintain scientific integrity." she said.

"Robust and scientifically defensible data sets are critical to informing and maintaining our environmental stewardship. We take our roles and responsibility to the land and environment seriously." Kenshalo added.

Pohl offered a couple of important takeaways.

One, "we have some really neat partnerships with the North Slope Borough and the Alaska Department of Fish and Game on the caribou movement and distribution analysis, ensuring a more objective analysis of how caribou are moving because we're not just relying on people sitting on the road system observing them.

"And I think it shows heightened scientific integrity that we are working with the partner agencies for caribou management, as well as the local government that oversees a lot of the subsistence monitoring and concerns. Caribou are an incredibly important subsistence and biological resource on the Slope," Pohl said.

Two, Pohl thinks one of the really important things with the caribou studies, or caribou monitoring, is the understanding of specifically the Central Arctic herd in Kuparuk and Prudhoe Bay has strongly "informed the engineering design and some of the management implications for the oil fields of the future … such as pipeline height standards and the offset distance between roads and pipelines so that caribou have fewer physical and visual barriers, making it easier for them to move more freely through the landscape."

What the group and their partners are learning from caribou monitoring helps ConocoPhillips with infrastructure design. "For example, right now pipelines have to be 7' or higher. Informing infrastructure standards can also include general layout, even to where drill sites are placed and how the shape and height of the roads may impact caribou. Incorporating biological monitoring to inform "science-based" engineering is something we are proud of" Pohl said.

Symbol of Kuparuk

"I think of caribou as the symbol of Kuparuk. In any given year, we have thousands of caribou moving through Kuparuk. It can be a really moving sight when the herd comes through. It's something that I think oilfield workers are very proud of," Pohl said,

"There's a lot of work that goes into protecting caribou as we move further west with our new developments or expand our existing fields. Understanding how to coexist with the caribou is one of our top priorities," Pohl said.

GIL MULL

Richfield Oil geologists examine an outcrop in the foothills of the Brooks Range in the early 1960s. The California oil company poured resources into North Slope exploration, gambling that field parties with air support could find huge oil fields.

Richfield, others go hunting, Kuparuk discovered 1969

Geologists pore over North Slope outcroppings; Richfield invested in exploration from the Foothills to the Arctic coast, while others scoffed at area's oil potential

By KAY CASHMAN
Petroleum News

The discovery of the Kuparuk oil field in 1969 was preceded by 10 years of field parties, seismic shoots and exploration drilling that yielded dry holes and resulted in several oil companies giving up on the North Slope.

According to a 2006 IHS Energy report on Alaska's Arctic, there were 10 dry holes drilled on the North Slope between 1964 and 1968 when Prudhoe Bay was discovered, and 53 dry holes compared to four discovery wells (including Kuparuk and Milne Point) between 1969 and 1971.

Luckily, ConocoPhillips' predecessor Richfield Oil was not one of the companies that walked away from northern Alaska.

In 1959 and the early 1960s, Richfield participated in the discovery of oil and gas fields across Cook Inlet, racking up success after success with such finds as the Swanson River field, Middle Ground Shoal, Granite Point and McArthur River.

Richfield's emphasis was on large promising structures beneath Upper Cook Inlet, but the events taking place in the far north on nearly treeless tundra would have greater significance and far-reaching consequences for both Richfield and Alaska, which became a state in 1959 largely because of Richfield's Swanson River oil discovery, creating an economic base for the state.

To the North Slope

In 1959 Richfield sent its first surface geological mapping parties to the North Slope.

In the summers of 1963 and 1964, at least six oil industry helicopter-supported field parties were fanned out across the central and eastern North Slope and into the 1002 Area of the Arctic National Wildlife Refuge.

The abandoned Navy camp and airstrip at Umiat on the Colville River in NPR-4 (today called National Petroleum Reserve-Alaska), served as a base of operations; at the time, this was the only improved airstrip on the North Slope other than the airstrips at Barrow and Kaktovik, which were too remote from the outcrop belt to be of use to industry geologists.

Umiat was a beehive of activity. Wien Airlines had a station agent and several bush pilots based there, as well as three-day-a-week scheduled flights from Fairbanks on its route to Barrow. Aviation fuel was available for purchase and a catering company had opened a kitchen for meals.

Most of the oil companies started off in mid-June working out of Umiat.

The helicopter of choice was the Bell 47G2, a small machine with a piston engine mounted behind a fish bowl-shaped bubble for a cockpit and an open tail boom. The main rotor blade was wood, with a stainless steel leading edge and a steel spar down the center of the blade.

The 47G2 held the pilot and two passengers, an extra 10 to 20 gallons of fuel in cans and a small amount of field gear on the side racks.

The helicopter could cruise at about 60 mph and without the

Humble buys in


GIL MULL

Despite Richfield Oil Corp.'s growing enthusiasm for North Slope exploration, limited budgets probably would have quashed the company's oil hunting efforts in the Arctic were it not for a strategic partnership it entered into with Humble Oil & Refining Co. in preparation to bid on leases in the State of Alaska's first lease sale for North Slope acreage in December 1964.

It was the first of many joint agreements between the two companies in the 1960s that led to an enduring and lucrative partnership on the North Slope.

"That partnership has to have been one of the all-time great deals for Humble," North Slope geologist Gil Mull said many years later. "It bought into half of everything Richfield had done to that point, which included the preceding years of surface field mapping, two seasons of seismic data (winters of '63-'64 and '64-'65), and a lot of federal leases Richfield had previously acquired — all for $1.5 million in cash and an obligation to pay for another $3 million worth of seismic data.

"So for $4.5 million, Humble got onto the North Slope after most of the other major oil companies already had surface mapping and seismic data and had already secured a land position up there," Mull said.

—Kay Cashman

GIL MULL

In early August 1963 at Cache I Lake, Richfield Oil Co. geologists Gar Pessel and C.G. "Gil" Mull worked out of a tent camp, using a Bell 47G2 helicopter and a Cessna 180 floatplane on the lake for transportation. Cache I Lake is a small lake near the Echooka River, close to the northeastern Brooks Range mountain front. Pessel discovered an oil saturated sandstone on the Sagavanirktok River near this location.

extra fuel, had a range of about 2 1/2 hours of flying time. The limited fuel range meant that most field parties soon ran out of work that could be done within range of Umiat. Thus, after a week or so, most of the field parties moved to widely dispersed tent camps located on river bars or lakes.

Cessna 180 an asset

In 1963, Richfield sent geologists Garnett Pessel and Gil Mull to the North Slope to build on the data acquired by field parties in 1959 and 1960 and U.S. Geological Survey reports from the 1940s and 1950s.

Richfield's 1963 field operation was similar to that of many of the other oil companies, with the exception that in addition to a helicopter, Richfield had chartered a single engine Cessna 180 to work with its field party for the summer.

"It was Cretaceous sand that just crumbled in your hand," Selman said. "He (Pessel) got all excited and wrote, 'If we can't find an oil field in something like this, I give up.'"

Early in the season the Cessna was equipped with wheel-skis so that it could operate on the frozen lakes as well as on the gravel strip at Umiat.

In mid-June 1963, Richfield moved its camp to Peters Lake in ANWR. The Cessna ferried camp equipment, a large amount of aviation gas and passengers to the campsite on the lake shore.

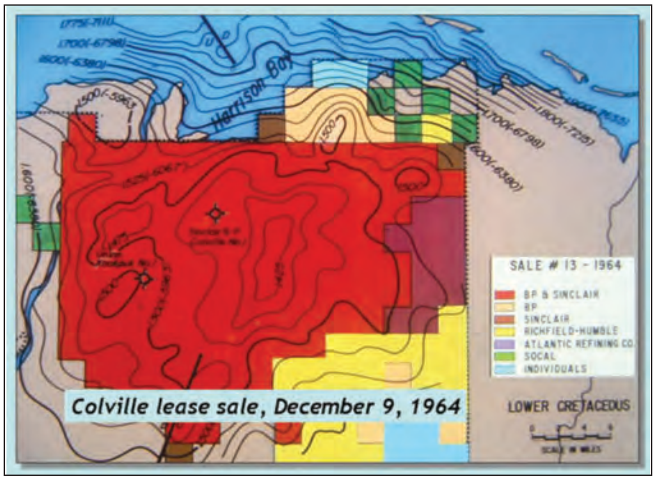
After the camp was established, the plane was used to ferry fuel caches to other lakes, fly back and forth to Umiat to mail in reports, ship rock samples and pick up food shipments that came in on Wien Airlines.

After the lake ice melted in early July, the plane was switched to floats and the pilot continued his routine, flying between the tent camp at Peters Lake, a subsequent camp at Cache One Lake near the Echooka River and a small lake at Umiat.

Most of the tent camps consisted of a large wall tent as a cook tent, an office tent and several sleeping tents. Most field parties consisted of four to six geologists, the pilots, a mechanic and a good cook, who was the key to a happy camp.

Field operations consisted of flying the geologists, two at a time, out to creek or river bluffs or mountain top outcrops to walk traverses, describe the rocks and map the geology on aerial photographs or topographic maps. At the end of a traverse or at the end of the day, the helicopter pilot would return to ferry the crew to a different location or back to camp.

Though it was a big country and most of the field parties were



GIL MULL

Dec. 9, 1964 lease sale

In 1963, ConocoPhillips predecessor Sinclair Oil and Gas Co. and British Petroleum, Sinclair's exploration partner in northern Alaska, moved a Western Geophysical crew north to Alaska's Arctic coast to make a 17 mile by 17 mile seismic grid survey.

According to G.L Scott, former Sinclair geophysicist, large structures beneath the Colville River delta and Prudhoe Bay were first identified and mapped from these seismic lines (oral communication, 1987). The Colville prospect was considered to be larger and structurally simpler than the Prudhoe Bay prospect.

The acreage over the Colville prospect was the first area selected for leasing, and Sinclair Exploration Manager Loren Ware advocated strong bidding (Bowsher, 1987).

The Colville acreage was offered at the 13th Competitive Lease Sale on Dec. 9, 1964, at which time essentially all of the leases that make up the present-day Kuparuk River unit were acquired (see map with this story) west of the giant Prudhoe Bay oil field. Sinclair and British Petroleum were high bidders on a total of 317,934 acres in a 50-50 partnership at the sale.

Smaller acreage positions were acquired by Atlantic Refining, Standard Oil Company of California and a partnership between Richfield Oil and Humble Refining.

—Information taken from ARCO's AC&O December 1981 publication

camped in separate locations and operating independently, it was not uncommon for two or three helicopters and field crews to end up on the same outcrops at the same time — all trying to be secretive and proprietary about what they were seeing and interpreting.

Evenings in camp were spent compiling data and updating the mapping.

And so it went for the summer. Most of the field parties had 2 1/2- to 3-month field seasons without break until the end of August, when they headed back into Umiat.

Report makes impact

Pessel and Mull identified two oil-filled sandy outcrops that summer, one on the Katakturuk River in the Arctic National Wildlife Refuge's 1002 area and another on the Sagavanirktok River south of

GIL MULL

J.C. "Harry" Jamison, Alaska district manager for Richfield Oil Corp. and later Atlantic Richfield Co., examines sandstone and conglomerate in the Tertiary Sagavanirktok formation near Sagwon in June 1964.

the Prudhoe Bay field discovery site.

Until that point, Pessel said they had been discouraged by the structures they saw in the Foothills.

But farther north along the coast, he said in an interview many years later, "We knew we were in a petroleum basin and we started seeing some potentially good sands.

"We were hopeful all along, but it consolidated our opinion about the potential of the area. It had the Big Three: source rocks, reservoir rocks and structures," Pessel said.

Late in that season after two months of exploring, Pessel sat down in his tent and penciled out the now famous note to Richfield management.

"Gil was looking over my shoulder the entire time, and we were conversing back and forth on the phrasing in the letter," Pessel said.

"We have a good section of excellent reservoir possibilities, and positive proof of the petroliferous nature of these sands. If one cannot get an oil field out of these conditions, I give up," wrote Pessel.

H.C. "Harry" Jamison, Richfield's district manager in Los Angeles, said the missive was brief, to the point and said all the right things.

It also didn't hurt that the man to whom the letter was addressed, Jamison's level-headed district geologist, Ben Ryan, wholeheartedly agreed with Pessel and Mull.

The letter Pessel wrote conveyed his and Mull's underlying excitement about the possibilities of the North Slope.

Pessel also helped destiny along when he and Mull gave Humble Refining executives a presentation on their findings during the winter of 1964-65.

"Humble came in with us that next summer," he recalled.

At a banquet held by Gene Rutledge in 1988, in honor of the men featured in his book, "Prudhoe Bay Discovery," Charlie Selman, Richfield's division geophysicist, recalled events leading to the decision to continue exploring the North Slope.

"It was Cretaceous sand that just crumbled in your hand," Selman said. "He (Pessel) got all excited.

Selman added to Pessel's letter, recommending that Richfield send a seismic crew up north.

Ryan attached a cover letter simply stating that he concurred with Pessel and Selman's recommendation and sent it to Jamison.

"As luck would have it," said Selman, "a drilling operation had been canceled somewhere else, so ... Jamison got the funds to put a seismic crew on the North Slope."

Richfield's fieldwork led to the discovery of the giant Prudhoe Bay oil field.

Atlantic purchased Richfield and the two companies merged in 1966 to become Atlantic Richfield Co., later changed to ARCO.

—Former Richfield (and later Humble) geologist Gil Mull contributed to the above story.

Sinclair drills Ugnu No. 1

The Kuparuk oil field was discovered on April 7, 1969, when Sinclair Oil and Gas and Sohio, a British Petroleum company, drilled exploratory well Ugnu No. 1.

Drill stem test No. 1 yielded 5,588 barrels of black oil with no water from the Early Cretaceous-aged Kuparuk formation "A" sand between 6,158 feet and 6,178 feet measured depth.

A subsequent one-hour flow test of that sand conducted on May 9, 1969, yielded a 24-hour calculated flow rate of 1,056 barrels of 24° API gravity oil per day, 189,000 cubic feet of gas (a gas-oil ratio of 170 to 1), with no water, per the Alaska Oil and Gas Association.

Alaska area geologist for Sinclair at the time, Christopher Lewis, said in a 2006 speech that Sinclair's desire for a successful well on the North Slope was tied to the possibility of acquisition by Gulf and Western. "The thinking was that if we would spud a well, our stock would go up and Gulf and

Western wouldn't get us," he said.

Sinclair President O.P. "Pen" Thomas said it would not have been a good deal for the company's shareholders to be purchased by Gulf and Western.

"We moved quickly and cut a deal with Atlantic Richfield to stave off Gulf and Western," Thomas told the ARCO Spark in a 1982 interview.

Before Sinclair became a part of Atlantic Richfield in 1969, it drilled Ugnu No. 1, the Kuparuk discovery well. Several dry holes preceded this well.

In a rush to drill

Lewis, then 74, told the story of Kuparuk's discovery in a presentation titled, "Three Big North Slope Surprises," at the Pacific Section meeting of the American Association of Petroleum Geologists in Anchorage May 9, 2006.

He said he was summoned to Sinclair's exploration offices in Denver on a Friday evening just before Thanksgiving 1968 by Regional Vice President Glen Simpson. (Simpson later became the Alaska general manager for ARCO.)

"I want you to go out there and stake a well location straight away," Simpson told Lewis.

The next day, Lewis climbed aboard a plane to Fairbanks where he ran into the field party chief of a Union Oil seismic crew working in the same area.

"I was able to use their camp and helicopter," he said.

The weather was very cold with temperatures dipping 40 degrees below zero Fahrenheit.

That first day Lewis said visibility was limited due to the frosting up of the helicopter bubble and as he and his surveyor were in the

A confusion of names

The first confusing name was that the Kuparuk oil field discovery well was named "Ugnu No 1" — Ugnu being the shortened name of a nearby river — though it was the discovery well for the Kuparuk reservoir, not the shallower Ugnu heavy oil

Compounding the confusion, early Kuparuk delineation wells were called "West Sak," although they were not targeting the West Sak heavy/viscous oil accumulation that overlies conventional oil in much of the Kuparuk River field. Rather, wells into the Kuparuk formation often drill through the West Sak formation.

ARCO Alaska officials told the Alaska Oil and Gas Conservation Commission in 1981 that between 1969 and 1980, ARCO and other companies drilled 25 wildcat and extension wells in an attempt to define the limits of the Kuparuk accumulation.

Jim Posey, who worked on the startup team, talked about that delineation drilling in the 2001 20th anniversary Kuparuk video.

"We wanted to know how far the field extended before we filed the papers with the state, so we had them drill the perimeters of the field, starting with West Sak No. 13, 14 … and going up to West Sak 20," said Posey, who worked on unitization for the startup team.

Posey said it was a multiple effort: they were trying to find the edge of the field, "at the same time do unitization and get this thing online by 1981, which was the target."

Today production wells in the Kuparuk oil field have names beginning with Kuparuk River unit, followed by the satellite name, if appropriate, and then by a pad and well number.

—Kay Cashman

ConocoPhillips GKA Assets

The assets held and operated in the Greater Kuparuk Area by ConocoPhillips Alaska at the end of 2021 largely came from the following companies in a combination of asset purchases, and company mergers and acquisitions since about 1959.

ARCO Alaska, Inc.
Atlantic Refining Company
Atlantic Richfield Company
ConocoPhillips Alaska, Inc.
Phillips Petroleum Company
Richfield Oil Corporation
Sinclair Oil & Gas Company
Humble Oil & Refining Company

back seat they could not help the pilot to find the location.

The next day he borrowed a tracked vehicle from the seismic crew and with one of their surveyors, set off across the tundra.

"We only had a few hours of daylight," recalled Lewis.

"With two surveyors aboard, suddenly I realized that we were going 180 degrees in the wrong direction. I saw the lights of Bud Helmerick's place to the northwest of our location. We needed to go southeast. We finally got to the site just before dark."

Catching "a break"

Lewis said he had spotted two odd-shaped lakes from air photographs and picked a location in between them because he thought it

ATLANTIC RICHFIELD CO.

A big tracked vehicle pulls seismic equipment in a "cat train" in 1969 for a North Slope seismic shoot by Atlantic Richfield.

would be easy to find.

They marked the spot with a flag and returned on the third day to finish plotting the well site.

Months later when drilling began in early 1969 Sinclair assigned Lewis to sit on the well.

"We were drilling at 6,000 feet without any hope of getting anything because we were downdip from the Colville High, and that was a dry hole," Lewis remembered, referring to a previous well the company had drilled.

"I was having my dinner when the crew said we had had a break."

In drilling parlance, "a break" meant the rate of penetration had increased because the drill bit encountered porous layers of rock.

"When I looked at the cuttings, I realized that we had an excellent oil sand," Lewis said. "I wanted a core to obtain a solid rock sample of the sand but the rig site did not have the connections to core in a 12 1/4-inch hole."

Wireless communication was usually so poor that Lewis realized he would have to travel to Fairbanks to confer by phone with his superiors in Colorado about the next step and then travel back to the North Slope, using up more than a day of precious drilling time in the process.

Instead, Lewis decided to ask the drilling crew to test the well.

Surprise, surprise

"Our surprise was complete when the test produced oil. We recovered oil at a rate of about 1,000 barrels per day in that well," he said.

The entire ploy paid off handsomely for Sinclair. The company's stock price rose, and Atlantic Richfield soon offered to buy the company in a friendly takeover.

At the time of the takeover, Lewis said Alaska was no longer a top priority at Sinclair. Company officials saw themselves as major players in the Rockies where Sinclair had made a number of significant discoveries.

Ironically, one of the first things Atlantic Richfield did when it took over Sinclair was to sell many of the company's assets in the Rockies.

Getting there and other challenges

1979-81: initial Kuparuk development, including KOC, CPF-1, first drill sites, temporary and permanent bridges

By KAY CASHMAN
Petroleum News

Morrison-Knudsen Co. and NANA Development Corp. did construction for ARCO Alaska. Here a drill rig bores hole for pipe supports on Kuparuk River crossing. Photo courtesy Washington Group

Getting there is half the fun — or challenge — could have been the motto for initial construction at Kuparuk.

First there were the sealifts and the struggle to get facilities modules to the North Slope in the short window each summer when there was an opening in the ice.

And once modules reached the North Slope, they had to be moved from West Dock at Prudhoe Bay, across the Kuparuk River, to the new field.

Initial Kuparuk facilities arrived on three sealifts:

The 1979 sealift brought in the warehouse, shop, vehicle storage and hanger. Workers were still installing those in the spring of 1980, along with doing piling work for modules and laying more gravel in advance of the 1980 sealift, which brought in the permanent base camp, sewage and power facilities.

Final facilities for initial production only arrived in the summer sealift of 1981.

The ARCO Spark, the company newsletter, said workers finished installing Kuparuk's 245-bed construction camp in the winter of 1979-80.

Six development wells were drilled along with two exploratory wells to confirm more high-potential Kuparuk areas.

Project growing

In 1980 ARCO was also putting together an expanded long-range Kuparuk development, a multibillion-dollar plan to include several working interest owners in the expanded 200-section development. In that plan three additional facilities (central processing facilities 2 and 3, and the seawater treatment plant) would be installed to meet Kuparuk pipeline capacity of 200,000 barrels of oil per day.

JIM WEEKS

"We have drafted a unit agreement and a joint operating agreement for the development which we're sending to co-owners so we can unitize the field," North Slope district Kuparuk engineer Jerry Pawelek told the ARCO Spark. "We hope to begin negotiations on this by late 1980 and we hope to have the field unitized by early 1981."

ARCO Alaska would be field operator and peak capacity of 200,000 bpd was planned for 1986 — a big change from an original projection of 60,000-80,000 bpd.

Jim Weeks, head of the Kuparuk project group, told the ARCO Spark that expansion altered the facilities thinking — the permanent camp was upgraded and the capacity for both more drill sites and more processing facilities was added.

Pawelek worked unitization, reservoir engineering and facility design, while Landon Kelly, the Kuparuk operations manager, ran the camp and oversaw facility design and installation.

The Kuparuk team

Weeks had been on the Prudhoe Bay design team in Pasadena when Prudhoe project manager Jim Middleton asked him if he wanted to move to Dallas and head up the new Kuparuk project.

"I was speechless — one of the few times in my life — when he called me into his office one Friday afternoon. ... I didn't sleep the entire weekend. I decided if he was crazy enough to ask me, I was crazy enough to take it," Weeks said.

By September 1977, Weeks was heading up the Kuparuk project out of ARCO's North American Producing Division in Dallas. (ARCO's Alaska office was just a district office at the time. It became ARCO Alaska Inc. in 1981.)

Weeks had met Jeff Lipscomb, an ARCO petroleum engineer, in 1976. In early 1977, Lipscomb had moved to Alaska for the Prudhoe Bay startup, returning to Dallas in July of that year. He had made his first payment on his house when Weeks asked him to work on the Kuparuk project. It would mean moving again, but he didn't hesitate to accept the offer.

Once they selected an engineering firm for Kuparuk, the eight-member ARCO Kuparuk team would be moving to the engineering contractor's offices.

In Alaska, Landon Kelly, known as the "John Wayne of the North,"

COURTESY STEVE HUBBARD

Derrick for Doyon rig 9 on side; Kuparuk Operations Center under construction in background.

left his job as operations manager at the Prudhoe Bay field to take a special assignment at Kuparuk, where he became the field's first operations manager.

"Landon was the traditional oil man," Lipscomb said. "No task was insurmountable, and he had contagious optimism."

"He had the highest enthusiasm for the project of anyone," Weeks said.

Kuparuk, the 'wild' river

One of the challenges of developing Kuparuk was getting there, Prudhoe being the connection to the Dalton Highway, known as the Haul Road, and initially the necessary connection to West Dock for module delivery, although Kuparuk later had its own dock facilities at Oliktok Point.

The sealift was due in August 1980 and materials for Kuparuk, including the power plant, would have to go across the Kuparuk River.

A bridge was needed. Weeks said plans were underway the previous fall, but permits didn't come through until after freeze-up — and the gravel that would be used for fill already had ice crystals in it.

"Kuparuk, I understand, means 'wild' in the Eskimo language," Weeks said. When the Kuparuk River floods at breakup, it becomes three miles wide. "We couldn't justify building a three-mile bridge, so what we did is build a bridge on the main channel" with two low-water crossings on either side. Even the central bridge would be expensive, so they chose the type of "massive, corrugated culverts used for train tunnels." The culverts were backfilled with compacted gravel.

"The actual strength that held the load up on the top of the bridge was not the culvert but the gravel," Weeks said. The gravel was key — it pushed against the sides of the culverts, giving them the strength they needed.

ROSE RAGSDALE

LANDON KELLY

"But when we built the bridge the backfill was frozen. You can pound on ice all day long and it's not going to compact," Weeks said.

At breakup, the gravel started to thaw out, the ice crystals melted "and the gravel lost its ability to push against the side shells of the pear-shaped culverts, and they collapsed."

It was June 9, 1980, when the culverts started to collapse at ARCO's $5 million Kuparuk River crossing.

In a 2001 interview with Petroleum News, Weeks talked about the bridge.

"Everybody needs a humbling experience in their career," he said. "Everybody remembers what they were doing when President Kennedy was shot. Well, I remember what I was doing the day that I got a call that the Kuparuk River bridge had collapsed. I was on vacation at a friend's house in Arcadia, California," Weeks said.

Temporary crossing needed

The bridge collapse closed the Kuparuk Spine Road — a road needed to move sealift modules to the field.

A temporary river crossing had to be in place by August to move 1,000-ton equipment-bearing modules. If the river crossing wasn't ready ARCO planned to move the

Atlantic Richfield Co. goes it alone

ROBERT O. ANDERSON

Although Kuparuk was discovered in 1969, shortly after Prudhoe Bay, it wasn't until early 1979 that Atlantic Richfield Co. (later called ARCO) announced it was proceeding with field development.

The initial drilling and development program for the first processing facility, associated drill sites and pipeline was tagged at about $484 million.

Average daily production of some 80,000 barrels of oil day was expected by 1982 and, with additional investment, another 250,000 bpd by 1984.

ARCO said the 1981 startup was the first phase of what could eventually become a multibillion-dollar investment among several companies holding leases in the Kuparuk field. The initial effort, however, was exclusively by ARCO on ARCO leases.

ARCO Chairman Robert O. Anderson said the company was moving ahead because it felt Alaska's negative investment climate, created chiefly through adverse tax policies, showed some sign of improvement.

Anderson also said that further development beyond the initial phase would depend on the economics of the project and the future investment climate in Alaska.

Just getting to development approval was a challenge.

Landon Kelly, on the team that studied Kuparuk development in 1976, told the ARCO Spark, the company newsletter, in early 1981 that even in 1978 they were unable to convince management to develop the field, which was considered "marginally economical."

Kuparuk oil was heavier than Prudhoe, 23 degrees API vs. 27 degrees API for Prudhoe. Kuparuk oil was 1.6% sulfur, the company said, compared to 0.5% sulfur for Prudhoe crude.

The net sand thickness averaged about 50 feet in the Kuparuk reservoir compared to nearly 600 feet at Prudhoe, and average initial well rates for Kuparuk were expected to be 1,500 bpd, compared to 10,000 bpd at Prudhoe.

The team tried again in 1979. By then rising oil prices and the national need for domestic energy made Kuparuk more attractive. Plus, in the winter of 1978 ARCO drilled two successful Kuparuk wells that were considered the key to 32-well Kuparuk development program.

"It's very exciting, though the expanded scope is making everything hectic," Kelly said.

The scope had expanded because ARCO decided to get the field online by April 1982 and at the same time work on expanding the project to develop the whole field.

The first phase, exclusively ARCO, targeted 20 sections, 20 square miles.

At the same time, ARCO put together a long-range plan for Kuparuk and was working with owners of adjacent acreage to agree on a development plan.

The long-range plan amounted to a 10-fold expansion and covered some 200 square miles.

Until the other lessees stepped up to the plate, Kuparuk development only began because of one dedicated company.

—Kay Cashman

equipment overland in the winter.

Weeks and Kelly purchased all the surplus 48-inch Alyeska Pipeline Service Co. pipe they could find in the state and used it to install a temporary bridge to meet the August sealift.

Weeks, who headed the Denver-based Kuparuk project group which designed, constructed and installed Kuparuk facilities said that "From the start, Kuparuk had … the reputation of being the down-to-earth, low-cost, sort of get-it-done-cost-effectively oil field. That was our mandate from the company."

The failure of the Kuparuk bridge didn't stop him and his team from trying different and innovative ways of doing things at Kuparuk.

"We developed a lot of new technology at Kuparuk, and we broke the paradigm that you couldn't start something up in the same year you shipped it," Weeks said.

He would become the first project manager for Kuparuk.

Permanent bridge next

After getting the temporary bridge in place to meet the sealift, a permanent bridge was required before the field could be started.

Because of the strength of the Kuparuk River breakup, pilings for a permanent bridge were massive: 42 inches in diameter, so big they could not be made in the United States, they had to come from Japan, lashed to the deck of a ship because of their diameter and 80-foot length.

At Kuparuk, 54-inch holes, 100 feet deep, were drilled for the pilings, but the ship encountered a storm in the Gulf of Alaska and some of the pilings went overboard.

Without the pilings in place water would fill the holes at breakup and thaw them out and the holes would collapse.

"We developed a lot of new technology at Kuparuk, and we broke the paradigm that you couldn't start something up in the same year you shipped it," Weeks said.

The Japanese could get them more piling, but not until September or October, and the holes needed to be saved. So they held a contest.

John Larson, an ARCO engineer, suggested using some of the surplus 48-inch pipe ARCO had bought for the temporary bridge, cutting the pipe into 15-foot lengths and putting a cap on each section.

Weeks said they hung a section of pipe into each hole, insulated the area between the 48-inch pipe and the 54-inch hole and backfilled. "We essentially put a plug in the top of the hole and froze it back in place," Weeks said.

Forty holes were saved. The replacement pilings came in and were put in during the fall of 1981, allowing the field to start producing oil.

Tired vehicles for modules

Ground speed was another problem: crawlers used at Prudhoe Bay only traveled a half-mile per hour and it was 40 miles from West Dock at Prudhoe to Kuparuk, so the Kuparuk team used rubber-tired vehicles with trailers that moved at 5 mph.

"We got the modules set on the piling in October of '81," Weeks said, and things were going so well that he thought with overtime they could bring Kuparuk up that year. ARCO authorized "a couple million" for overtime and incentives, and with a construction force of 500 including 120 ARCO employees working around the clock the field started up three months ahead of schedule, on Dec. 13, 1981.

CONOCOPHILLIPS ALASKA

Photo from Kuparuk startup historical archive.

Following 1981 startup, Kuparuk build continues

CPF-2, CPF-3, seawater treatment plant, drill sites added; one-day production record set in October 1985 of 264,490 barrels, oil price crash in late 1985

By KAY CASHMAN
Petroleum News

The years immediately following the mid-December 1981 startup of the Kuparuk River oil field saw major facilities work completed at the field, with the addition of the second and third central processing facilities and the seawater treatment plant, construction of drill sites and an expanded Kuparuk sales line.

By the end of 1986, big development projects at Kuparuk were considered complete, oil prices had plummeted, and operator ARCO Alaska's focus began to shift to reservoir management.

The 1982 sealift included modules for the Kuparuk field including additional compression capacity for CPF-1 so the facility could handle more natural gas and maintain production levels.

The sealift also contained the first increment of the Kuparuk waterflood project for installation at CPF-1, the first large-scale water injection project on the North Slope.

Production from Kuparuk, which had begun the previous December, was averaging more than 90,000 barrels per day in 1982.

Operator ARCO Alaska had 163 employees working at Kuparuk, with about half of them on the slope at any given time.

The first waterflood on the North Slope was initiated in February 1982 at Kuparuk, more than a year ahead of the Prudhoe Bay waterflood.

Kuparuk waterflood began with 3,200 bpd of water at drill site 1A. The rate was to be gradually increased to 5,000 bpd, and then expanded to other wells at drill sites, such as 1E.

Because of Arctic conditions, the water had to be heated before injection to avoid having it freeze in the pipelines. And the pipelines had to be insulated and freeze protection systems installed.

CONOCOPHILLIPS ALASKA

Installation of the second processing facility, CPF-2, followed its arrival on the 1984 sealift, which also carried a tripling of bed capacity for the Kuparuk Operations Center.

"The key is to keep the water moving and keep it warm," said Landon Kelly, Kuparuk operations manager at the time. "And we have to pump enough volume to overcome heat loss as the water travels down through the permafrost."

Water came initially from wells; water for full-field waterflood would come from the Beaufort Sea.

By March 1982, 22,000 bpd of water were being injected into wells on drill sites 1A and 1E, Kelly said.

In Phase I the rate was gradually increased to 50,000 bpd.

ARCO said it expected to recover an additional 800 million to 900 million barrels of oil with waterflood.

Pipeline; dock at Oliktok Point

A joint venture agreement between Kuparuk leaseholders was reached in 1983 for a 24-inch pipeline, expected to handle as much as 250,000 barrels per day by the late 1980s.

The Kuparuk River oil field's 16-inch line, which could handle more than 100,000 bpd, was converted to other service once the 24-inch line was completed.

In 1983, sealift modules for Kuparuk were offloaded at a new dock at Oliktok Point, west of Prudhoe Bay, and then transported 10 miles south to the Kuparuk field. Previously Kuparuk modules came into Prudhoe Bay and were transported 40 miles overland.

The 1983 sealift carried the utilities portion of CPF-2; the oil handling portion of the new facility was scheduled for the 1984 sealift.

Major expansion in 1984

Installation of the second processing facility, CPF-2, was begun following its arrival on the 1984 sealift, which also carried a tripling of bed capacity for the Kuparuk Operations Center.

The sealift also included a crude oil topping plant that would be producing 3,000 bpd of diesel fuel by the end of 1984.

The sealift arrived a week ahead of schedule and that contributed to getting CPF-2 online at the end of October 1984, more than a month early, increasing production by 75,000 bpd and raising the field's total daily production to 182,000 bpd by the end of the year.

The new 24-inch Kuparuk pipeline went into operation October 6, 1984.

Harold Heinze, president of ARCO Alaska in the mid-1980s, attributed the early startup of the Kuparuk River oil field to exceptional teamwork, as well as "excellent productivity" by field construction workers and supervisors. "This is the fastest major facility ever put into service on the North Slope."

HAROLD HEINZE

According to the1985 Annual Report on Alaska's Mineral Resources from the U.S. Geological Survey, oil output from the Kuparuk River oil field at the end of 1984 pushed Kuparuk past the nation's previous No. 2 oil producer, California's Elk Hills, to make it the country's second largest producer.

During 1984, Kuparuk River oil field production averaged 126,400 barrels per day, approximately 16% more than in 1983. During that year, approximately 110 production wells were drilled in the Kuparuk field, bringing the total number drilled to date to 240.

A landmark was reached August 23, 1984, when the field produced its 100 millionth barrel of oil.

Drilling records

The Alaska Spark reported in December 1984 that drilling records were being set nearly every month at Kuparuk. During development drilling in 1980, it took an average of 22 days at a cost of $2.5 million to drill and complete a well.

The average time had dropped to 11 days and the average cost to $1.5 million, with the 1984 drilling record held by Parker rig 141. It drilled and cased a 6,704-foot well in four days, 23 and three-fourths hours, a drilling average of 1,348 feet per day.

Four rigs had been working at Kuparuk since the spring of 1984, with 117 new wells drilled by the end of the year; 155 wells were planned for 1985.

West Sak pilot

ARCO also announced the startup of a pilot project in 1984 to determine the feasibility of developing the multibillion-barrel oil accumulation, West Sak.

This accumulation overlies the Kuparuk oil field at depths of 3,000-4,000 feet.

ARCO said it involved injecting hot water into the reservoir to heat the oil sufficiently to reduce its viscosity and make it easier to produce.

In 1984, 13 producing and injecting wells were in operation in the West Sak pilot project, producing 1,000 barrels of oil per day.

Major builds in 1985

Major construction by ARCO at Kuparuk in 1985 included water-

Kuparuk Operations Center.

flood, with construction for the seawater treatment and injection plants underway, the Alaska Spark said in May 1985.

The seawater treatment plant, two modular buildings connected by a 100-foot Arctic walkway, was scheduled to go in at Oliktok Point some 20 miles from the Kuparuk main camp and would process 585,000 barrels of seawater a day through four intake bays.

A jet pump in the new seawater treatment plant would separate marine life from the Arctic water and safely return them to their environment.

Kuparuk set a one-day production record in October 1985 of 264,490 barrels.

"We had expected that Kuparuk production would not reach 250,000 barrels a day until late 1986, after the installation of a third central production facility," said Ben Odom, ARCO's senior vice president for operations. "However, our aggressive and innovative engineering and operations people have been able to achieve higher rates than expected from only two production facilities."

The water injection program went into operation Oct. 28, 1985, and was expected to triple recoverable oil, from 500 million barrels without waterflood to 1.5 billion barrels with waterflood.

"It's a major shift from primary production to secondary waterflooding," senior reservoir engineer Paul White told the Alaska Spark. "The recent history of Kuparuk focuses on expanding the field by drilling new wells. We'll still be expanding the field, but the focus will be coming around to managing a developed field.

"This will include developing the less productive areas of the field," White said, "where the costs will be about the same, but the benefits are much less."

Dana Dayton, manager of Kuparuk reservoir engineering, told the Alaska Spark in 1986 that "CPF-3 is the culmination of a development era. This year is unique because of a feeling of transition which many of us have.

"While we may have a big sense of satisfaction and accomplishment, we may also have some apprehension about the change from development to reservoir management," she said.

The increase in Kuparuk oil production was in part responsible for the 5.6% increase in Alaska oil production in 1985 and for the highest U.S. oil production level recorded since 1974 (World Oil, August 1, 1985).

Kuparuk passed the 200 million barrel production mark January 8, 1986, two months ahead of schedule, with daily output averaging approximately 240,000 bpd.

1986 sealift last planned

The 1986 sealift was considered ARCO's last committed shipment of facilities to the North Slope, ARCO said in January of that year. For the first time since the discovery of oil on the North Slope, no future major projects were in the design or construction stages, and no new facilities were planned for the 1987 sealift or beyond.

The 1986 sealift included Kuparuk's third central production facility which would allow development of the northern portion of the field.

Kuparuk also had modules for five new drill sites on the 1986 sealift.

Skilled worker shortage

In 1983, 1984 and most of 1985, ARCO advertised in Alaska for skilled instrument technicians and other oilfield operating personnel to operate the new facilities and did receive Alaska applicants.

"The problem is that there simply are not enough experienced and technically qualified Alaskans to fill the large number of positions which are being created by the new facilities," said Heinze. "We have created so many new jobs in the past several years, in bringing online new facilities that we have already drawn heavily from the pool of qualified Alaskan workers."

As a result, he said, ARCO had begun placing ads in Lower 48 papers.

1986 downturn

According to the1987 Annual Report on Alaska's Mineral Resources from the USGS a decline in the world price of oil that began in late 1985 continued into 1986.

Between December 1985 and July 1986, the price declined from about $27 per barrel to $9 a barrel.

By the end of 1986, the price of North Slope crude oil had increased a little, to $14.25 a barrel delivered to the West Coast (Petroleum Information's Alaska Report, January 7, 1987).

Alaska's economy was especially vulnerable to fluctuations in crude oil prices because 85% of the state's revenue at the time was derived from royalties and taxes paid on state-owned oil and gas leases, per the 1986 Alaska Division of Geological and Geophysical Surveys.

DGGS said the sensitivity of exploration for, and production of, oil fields to world oil prices was reflected in the curtailment of many industry activities.

For example, the Milne Point oil field, the third field to produce on the North Slope, was completely shut down by the end of the year.

The major operators had announced drastically reduced capital budgets, which affected all aspects of the business and had a trickle-down effect on other industries in the state.

By early March 1986, ARCO said the declining price of oil had forced it to reduce its North Slope development drilling activity by nearly 50%.

Of the nine drilling rigs operating on the North Slope earlier in the winter, five were to be idled by the end of April or early May, leaving four rigs drilling new production wells for ARCO, only one at Kuparuk, with an estimated 400 North Slope jobs affected.

The cut in development drilling was part of ARCO's 30% capital spending reduction announced in February 1986.

The number of wells to be drilled at Kuparuk was reduced from 150 to 90 that year.

1987 production, prices

For 1987, the price of North Slope crude oil delivered to the West Coast rose to a high of $18.75 per barrel in August and then declined to $15.75 per barrel by the end of the year.

According to the 1988 Annual Report on Alaska's Mineral Resources from USGS, Alaska oil production increased by about 90,000 bpd in 1987, mainly the result of production increases from the Kuparuk River and the Endicott fields.

The daily rate of oil production increases from the entire state of Alaska at the end of 1987 amounted to 1,950,322 barrels, or about 23% of the United States' daily production.

In 1987, unofficial production data indicated that Alaska, with 2.0 to 2.1 million barrels of oil per day, had passed Texas, with 1.96 million barrels in daily oil production (Anchorage Daily News, Jan. 14, 1988).

The Kuparuk River field produced about 99.6 million barrels of oil in 1987 or an average of about 273,000 bpd.

1988 activity

The Alaska Oil and Gas Conservation Commission issued 157 drilling permits in 1988; 135 development wells and exploratory wells were drilled. Seismic exploration was underway at Granite Point, Kuparuk River and Yukon Flats.

The Prudhoe Bay, Kuparuk River, Lisburne and Endicott North Slope fields produced almost 95% of the state's total oil in 1988.

TAPS was carrying around 2.1 million barrels of this oil daily.

1989 challenges

Following the Exxon Valdez oil spill in March 1989, the Alaska State Legislature increased the severance tax on oil produced from

Different from Prudhoe, but ...

A 1983 article in the ARCO Spark, the company newsletter, gave some insight into work at the new Kuparuk oil field, which was producing 100,000 barrels per day.

"There's an attitude up here that everybody's looking for oil," said Bob Appling, Kuparuk operations manager. "It's a personal pride that everyone shares, and everyone sees to it the job's done right."

Appling said there are a number of differences between Kuparuk and Prudhoe Bay.

"Because Prudhoe can still produce more oil than it is allowed to sell, in some cases, repairs can be made in a less than critical manner.

"Over here, we get to sell every barrel we can get our hands on. If something goes down, man, you get it fixed right then and back into production. Every minute lost is less money to the company. We take all down-time very seriously."

Appling said that Kuparuk people are constantly looking for ways to boost production levels. "Not a week goes by that somebody isn't in here with an idea. Some we can use, some we can't. But it sure helps to have that kind of input," he said.

Appling listed a number of people as responsible for the field's first-year success, above all Landon Kelly, the field's overall operations chief. "I think everyone would agree that Landon is the single most important player at Kuparuk. He's the guy who pushed this field as a high priority long before it became one. And he's the one largely responsible for bringing it on earlier than anyone expected."

the Prudhoe Bay and Kuparuk River fields by 20% and 65% respectively (Alaska Report, June 7, 1989).

The impact of this increased taxation along with fluctuating oil prices was reflected in many industry activities: development at the West Sak project was postponed and some development drilling in the Kuparuk River field was delayed; on the other hand, the Milne Point oil field, in a "warm shutdown" mode since 1986, resumed production in April 1989 due to improved oil prices.

In June 1989, the 7 billionth barrel of North Slope crude oil was produced.

Overall production from the North Slope averaged about 95,000 bpd less in 1989 than in 1988 (Alaska Report, December 27, 1989). About one-third of the reduced production was attributable to the Exxon Valdez oil spill, and the remaining decline in production was the result of maintenance undertaken by the fields' operators.

A total of 130 development and service wells were active in Alaska in 1989, 12 in the Cook Inlet basin, 13 at the Endicott field, 31 at Kuparuk River, six at Milne Point and 68 at Prudhoe Bay, per AOGCC's May 1990 bulletin.

More prolific than expected

In 1969 Atlantic Richfield said the Ugnu No. 1 discovery well was "one of the most significant follow-up wells to Prudhoe Bay No. 1" because it led to the discovery of the Kuparuk River oil field.

North America's second-largest oil field, Kuparuk was originally thought to hold recoverable reserves of approximately 1.6 billion barrels. By year end 2021, Kuparuk River Unit (including its satellites) have produced 2.8 billion barrels.

Ugnu No. 1 was drilled by Sinclair and Sohio, but since Sinclair and Atlantic Richfield had merged earlier in 1969, Atlantic Richfield had a strong ownership position in the new field and would become the field operator.

In 1987, unofficial production data indicated that Alaska, with 2.0 to 2.1 million barrels of oil per day, had passed Texas, with 1.96 million barrels in daily oil production (Anchorage Daily News, Jan. 14, 1988).

Although only Atlantic Richfield leases were involved in Phase 1 of the Kuparuk development in 1979, several other oil companies later agreed to an expansion of the unit to include surrounding leases that they held.


PAUL NORGAARD

By 2001 ARCO owned more than 50% of the total Kuparuk River unit leases. Other leaseholders in 2001 included BP Exploration (Alaska) Inc., Union Oil of California, ExxonMobil Oil Corp., Phillips Petroleum Co. and Chevron Corp.

By Dec. 1, 2021, ConocoPhillips held 94.5% of the working interest in the Kuparuk participating area within the Kuparuk River unit, which encompasses a total of 271,475 gross acres, and varying working interests amongst the Meltwater, Tabasco, Tarn and West Sak satellites ranging from 89.2%-94.7%.

Initial production, or Phase 1, from the Atlantic Richfield-operated Kuparuk River oil field was from 40 wells on five gravel drill sites. A 16-inch diameter, 26-mile pipeline was built to carry Kuparuk oil to Pump Station 1 of the trans-Alaska pipeline at Prudhoe Bay.

In 1981, ARCO Alaska President Paul Norgaard said in a statement

Harold Heinze, president of ARCO Alaska in the mid-1980s, attributed the early startup of the Kuparuk River oil field to exceptional teamwork, as well as "excellent productivity" by field construction workers and supervisors.

that Kuparuk field startup, which occurred Dec. 13, 1981, was more than three months ahead of schedule.

By giving the project priority status, ARCO Alaska was able to speed up completion. Norgaard said 120 employees worked round the clock during the last few weeks of the project to bring the field online.

The project was expected to achieve an average daily production of 80,000 barrels of oil per day. A year later, on Dec. 13, 1982, Atlantic Richfield said that the field was averaging 87,000 barrels a day.

Kuparuk production peaked at 322,000 bpd in 1992.

On Jan. 10, 1986, Kuparuk cumulative production passed the 200-million-barrel mark.

In July 2005, cumulative production reached 2 billion barrels, and Kuparuk and its satellites have produced more than 2.8 billion barrels as of the end of 2021.

More challenging than Prudhoe

In a 2010 interview, H.C. "Harry" Jamison recalled the 1960s forward when he began as a young geologist with Richfield Oil Co. (predecessor to Atlantic Richfield). Jamison was generally regarded as the Richfield executive most responsible for the discovery of the Prudhoe Bay oil field, though he steadfastly maintained that the feat was the best of team efforts.

C.G. "GIL" MULL

H.C. "Harry" Jamison, Richfield Oil Corp.'s (left) exploration supervisor for Alaska confers with Ben Ryan, Richfield district geologist for Alaska, during a visit to the company's first seismic operation on the North Slope in December 1963.

He said the economics of the Kuparuk oil field were questionable from the original discovery in 1969 through the early 1980s:

"The development wasn't really" seriously considered "until the middle 1970s," he said, "primarily because in comparison with Prudhoe the production would be considerably lower, the oil was more difficult to get out of the ground, and it was another 35 miles away, so it required a separate development pattern and distribution system."

JUDY PATRICK

Kuparuk flowlines

1990s a time of challenges, discoveries at Kuparuk

ARCO Alaska/BPX align at Kuparuk; satellites West Sak; Tarn, Tabasco commence commercial production

By KAY CASHMAN
Petroleum News

In 1990 Iraq invaded Kuwait and North Slope crude soared to $30 a barrel.

But the bump in oil price did not immediately translate into increased North Slope development and production, in part because the price did not remain in the $30s, but often sank into the low $20s and teens, averaging $21.50 for North Slope crude for the year.

Alaska oil and gas production in 1990 totaled 665.5 million barrels of oil and natural gas liquids, a 5.2% decrease from 1989 levels.

Daily Alaska oil production averaged 1.82 million barrels.

The 8 billionth barrel of crude oil flowed through the Trans-Alaska Pipeline System, or TAPS, in late December 1990.

The North Slope produced 98% of the state's oil that year; Cook Inlet produced the balance.

During 1990, there were 1,498 producing oil wells, 111 gas wells, and 539 service wells active in Alaska. Of these, 114 development and service wells were drilled in 1990: 14 in Cook Inlet, one in the East Barrow gas field, 13 in the Endicott oil field, 24 at Kuparuk River, four at Milne Point, two at Point McIntyre and 56 at Prudhoe Bay.

Overall production from the North Slope averaged 1.79 million barrels of oil per day; 90,000 bpd less than in 1989. Part of this loss was due to extensive maintenance and repair work by ARCO Alaska and BPXA at their Prudhoe Bay facilities.

Most development drilling on the North Slope in 1990 occurred in the Prudhoe Bay and Kuparuk River fields, the two largest oil producers in the United States.

The Alaska Oil and Gas Conservation Commission approved 173 drilling permits in 1990; this was a 31% increase over the 132 wells permitted in 1989. Thirteen exploratory wells and 114 development and service wells were drilled.

Seismic surveys were conducted on and offshore the North Slope, including in the Greater Kuparuk Area.

Thirty modules

In July 1990, ARCO Alaska announced plans to build some 30 modules in Alaska over the next 16 months, mainly for projects at Kuparuk, with work expected to start in October.

Jerry Pollock, then engineering manager for the Kuparuk and Cook Inlet fields, said the projects would include 22 modules for two new drill site production facilities at Kuparuk, other modules to make environmental improvements to Kuparuk's flare system and modules to expand production at existing Kuparuk drill sites.

Tarn discovered, modules

On February 3, 1991, the wildcat well ARCO KRU (Bermuda) 36-10-7, drilled in the southwest corner of the Kuparuk River unit, discovered the Tarn satellite field.

Also that month ARCO began transporting 11 Alaska-made drill site production modules from Anchorage to the North Slope.

The 11 modules were destined for a new drill site in the Kuparuk River oil field.

"This is the first time that all of the facilities for a new Kuparuk drill site have been constructed in Alaska," the company said at the time.

ARCO planned to build an additional 50 modules in Alaska over the following two years for two new drill sites at Kuparuk as well as expansion of existing Kuparuk and Prudhoe Bay drill sites.

Update on EOR

In 1991, the Kuparuk River field's owner companies were evaluating new methods of enhanced oil recovery.

Going back to 1983 Kuparuk was the first North Slope field to use waterflooding to increase oil recovery.

In 1988 a miscible water-alternating-gas, or MWAG, enhanced oil recovery, or EOR, pilot was put in place in the Kuparuk River unit.

This original pilot was implemented on two drill sites previously on waterflood.

1991 production records

March 1991 saw a single-month production record from the Kuparuk River field of 10,068,358 barrels.

The field set new monthly production records — highest average daily rate ever produced for a given calendar month — in nine consecutive months in 1991, February through October.

"Kuparuk Challenge" initiative

In 1991, ARCO Alaska management issued what was known as the "Kuparuk Challenge."

Larry Shakley, Kuparuk field manager from 1991-94, reflected on those three years in a 2007 email to Petroleum News.

"When I went to Kuparuk in 1991, costs were rising, and production was declining.

"Working closely with the Engineering Department, we developed a program to extend the economic life of the Kuparuk field called the 'Kuparuk Challenge.' Over the next few years, costs were brought under control and Kuparuk production increased," he said.

"Each department and work group made positive contributions to finding innovative ways to improve profitability and productivity at Kuparuk. The Kuparuk Challenge was a clear demonstration of what can be accomplished when everyone understands what needs to be done and works together to meet the objectives," Shakley said.

And what was memorable about Kuparuk?

"The people — they were some of the most innovative individuals I have had the pleasure of working with in my career at ARCO. They did not shrink from a difficult situation but worked together to find solutions to problems that some people did not think were possible. They had a great sense of humor and always enjoyed showing the Anchorage executives they could do the impossible."

Dec. 15, 1991, saw a single-day production record of 352,950 barrels of oil from Kuparuk.

The Kuparuk River field marked its 10th anniversary in December 1991 with new production records.

Performance exceptional

H.L. "SKIP" BILHARTZ

"The performance of the Kuparuk field has been exceptional," said H.L. "Skip" Bilhartz, who was ARCO Alaska's president before Ken Thompson. "Production is at record levels because of investment in new wells and facilities by the owner companies, and because of the efforts of the ARCO employees who engineered, built, operate and maintain the field."

When the Kuparuk River oil field went online in December 1981, engineers expected production to ultimately peak at 250,000 bpd with total recovery of 1.2 billion to 1.5 billion barrels of oil.

KEN THOMPSON

At startup in 1981 Kuparuk was producing from a 20-square mile area in which ARCO owned all the leases. The field had one major production facility, five gravel drill sites, 40 producing wells and a 26-mile, 16-inch pipeline capable of delivering 80,000 bpd to Pump Station 1.

In 1991, 10 years after startup, the Kuparuk River unit encompassed more than 200 square miles, had three major processing facilities, the seawater treatment plant, 40 gravel drill sites, 367 producible wells, 285 injection wells

CONOCOPHILLIPS ALASKA

Kuparuk drill site

and a 24-inch pipeline capable of moving 300,000-plus bpd.

New output records in 1992

During 1992, there were 1,599 producing oil wells, 112 gas wells and 599 service wells active in Alaska, per the Alaska Oil and Gas Conservation Commission.

Of these, 137 development and service wells were drilled in 1992: 12 in Cook Inlet, three in the Endicott field, 46 at Kuparuk River, 65 at Prudhoe Bay, six at Point McIntyre, four at Walakpa and one elsewhere on the North Slope.

According to the 1993 Annual Report on Alaska's Mineral Resources from the U.S. Geological Survey, the Kuparuk River field, the nation's second largest oil field, continued to set new production records.

The field produced 118.5 million barrels of oil in 1992, up 4.4% from 113.5 million barrels in I991.

Increased production came from the western section of the field, coupled with good performance of operator ARCO Alaska's enhanced recovery projects.

In 1992, there were a total of 700 wells of which 371 were production wells. Most wells were drilled on 0.65-square-kilometer spacing, but by fall 1992 drilling underway was on a tighter, 0.32-square-kilometer spacing.

Originally, production from the Kuparuk River field was expected to peak at 250,000 bpd with ultimate recovery of 1.2 billion to 1.5 billion barrels. By 1992 company engineers expected production to remain in the 300,000 bpd range through 1997 and ultimate recovery to be 1.8 billion to 1.9 billion barrels.

Special efforts to control costs of the Kuparuk development had begun to pay off by the end of 1992.

This was especially significant at Kuparuk where development costs were three times more per barrel of developed reserves than at the Prudhoe Bay field. Transportation costs were also greater due to distance from the trans-Alaska oil pipeline and the premium paid to move heavier Kuparuk formation crude oil.

EOR expanded to third drill site

In 1993, Kuparuk received the ARCO President's Safety Award for Central Processing facility 2, or CPF-2, and the Kuparuk spill response center was completed, and the Earth Energy Partners Program was started.

Also in 1993, the 1988 EOR pilot was expanded to a third drill site to test the MWAG process in an area previously flooded by an immiscible water-alternating-gas, or IWAG, recovery technique.

JUDY PATRICK

Kuparuk wellhead

Per the USGS 1994 Annual Report on Alaska's Mineral Resources, in 1993 the Kuparuk River field joined the ranks of only 14 other oil fields in the United States that had produced a cumulative total of more than 1 billion barrels of oil.

The Kuparuk River field was the second largest domestic oil producer after the Prudhoe Bay field, producing about 315,000 bpd in 1993. For the entire year Kuparuk produced 115.2 million barrels of oil, down 3.3 million barrels (2.8%) from 1992.

As of the end of 1993, there were 381 producing wells out of a total of 700 drilled in the field.

Development drilling suspended

In 1994 production from the Kuparuk River oil field declined to 306,288 bpd but was still above original projections of 250,000 bpd.

There were 393 production wells in the field in 1994.

Operator ARCO Alaska suspended development drilling in the Kuparuk field in July 1994 as part of a cost-cutting operation driven by low oil prices.

Kuparuk margins thin

The margins at Kuparuk were thin, an article in The Crude Gazette, the Kuparuk newsletter, explained in 1994.

"Anything and everything can impact our margins, including OPEC, the state Legislature, production, operating costs and capital spending," said Dan Lawrence, then a manager at ARCO Alaska.

At a West Texas Intermediate price of $16 a barrel, the budget projection for 1994, the margin on Kuparuk crude was 36 cents a barrel, he said. Unfortunately, oil prices had been $1 to $2 a barrel below budget so far in the year, so, he told Kuparuk readers, "you can see it's not a favorable situation in which we find ourselves."

The price of crude oil impacted the entire company: a staff reduction of 750 was announced in June 1994.

Then-ARCO Alaska President Ken Thompson said while the reductions were painful for all employees, they were "necessary to enable ARCO to be a long-term competitor in the global market."

The company had 2,800 employees in 1990; that number was down to 2,350 in 1994; and the goal was 1,600.

Thompson said reductions in Alaska would affect every area of the company, both Anchorage and the North Slope.

He said ARCO Alaska would continue to explore for new economic sources of oil in areas close to existing fields and available transportation and would seek new ways to flatten decline of production from existing fields, and even stem that decline.

The Kuparuk drill site development group was established in 1994 to provide economic evaluation, design and construction of wells and facilities for Kuparuk development projects, combining functions of petroleum engineering, facilities, materials and drilling.

The group worked closely with Kuparuk production to meet Kuparuk field objectives.

Crude oil price still low

In January 1994 the price of North Slope crude had dropped to a dismal $6.57, improving a little through the year and ending at $10.47 per barrel in December.

Nonetheless, some drilling was done at Kuparuk, James Thantham and Mike Zanghi reported in The Crude Gazette.

Parker 245 broke field records, they said.

After being stacked for five months, the rig drilled more 12-1/4 inch hole in a single 24-hour period than ever before, 4,627 feet, setting the top 10 12-1/4 inch footage records for the field.

The second well drilled, 1R-33, set field records for measured depth and departure. The well had a total depth of 15,530 feet and the departure from the surface location was 12,775 feet, with a total vertical depth of 6,946 feet, a measured depth to total vertical depth ratio of 2.2.

The bottom hole of the well was three miles from 1R pad, and between two wells from 3H pad.

The third well drilled, 1R-34, held the field's second longest measured depth at 13,570 feet with a departure of 10,467 feet.

Tabasco commercial

In 1995 Kuparuk got its own athletic club, no small thing for the field's workers.

A well drilled and tested in 1995 indicated the shallow Tabasco heavy oil prospect could be commercial.

The Kuparuk River oil field contributed 293,149 bpd in 1995 to Alaska's total oil production. (North Slope oil fields produced 555.8 million barrels of oil and natural gas liquids in 1995, 97.3% of the state's total.)

Because production at the Kuparuk River oil field peaked in 1991, new development wells were planned and in March 1995 the owners received funding approvals for the large-scale enhanced oil recovery, or LSEOR, project at Kuparuk which would increase recovery.

State approves LSEOR

The Alaska Spark reported in October 1995 that the state of Alaska had approved the LSEOR project at Kuparuk.

LSEOR was expected to extend the life of the Kuparuk field and increase its oil recovery by more than 200 million barrels.

The project would use approximately 100 million barrels of Prudhoe Bay natural gas liquids that would be transported to Kuparuk through the Oliktok pipeline and reinjected at Kuparuk.

The Kuparuk EOR process mixed the field's own lean gas with the imported Prudhoe Bay NGLs to make a "souped-up gas," miscible injectant or MI, which was injected alternately with water, acting as a solvent and displacing most of the oil left behind by water injection toward producing wells.

Approximately 35% of the NGLs would eventually be produced as part of the Kuparuk crude stream. Changes in state tax regulations as they applied to NGLs made the project more attractive to ARCO and the other co-owner companies.

Some $135 million would be spent on 66 injection and production wells in the field and the companies would also invest $38 million in two new facility modules.

As mentioned, ARCO began testing miscible gas EOR on two of Kuparuk's 42 drill sites in 1989, and field owners approved LSEOR and expansion of the process to 20 drill sites in the southern half of the field.

Tuan Ma, then Kuparuk development EOR coordinator, told the Alaska Spark in February 1997 that Kuparuk's LSEOR project "charged out of the gate on schedule" on

3D seismic advantage

The latest seismic technology, 3-dimensional, helped ARCO Alaska and its partner, BP, locate untapped oil reservoirs beneath the earth versus the much less effective 2D seismic.

The main difference between 2D and 3D seismic is that 2D data is collected with a single line of sensors and a single line of shot points. The resulting display is a vertical slice of the earth. Explorers must hope that the lines are continuous going away from the slice or perform more 2D slices to see that the formations actually are continuous.

With 3D data collection explorers use a large array of seismic receivers and an array of shot points, getting a much more complex data set that can be displayed and rotated looking at the shapes of the formation in 3D space.

The cost of 3D in the mid-1990s was 10 times more that of 2D because of the complexity of acquisition and processing, but the volume of data was at least 100 times more.

3D seismic was helpful in identifying and locating other reservoir intervals not presently produced in the Kuparuk River field, as well as fault blocks outside field limits.

"Some of the satellites are very low risk and others are a gleam in geologists' eyes," Mike Richter, vice president, exploration and land for ARCO Alaska in the 1990s, said in a 1997 interview.

"Our 3D seismic this year is probably going to set a record. We'll probably have more than 500 square miles, with 200 square miles west of Kuparuk River field and the other 300 square miles in the Point Thomson area," he said.

—*Kay Cashman*

CONOCOPHILLIPS ALASKA

Exploration drilling at Kuparuk.

September 1, 1996.

The miscible injection rate quadrupled from some 50 million cubic feet per day to 216 million cubic feet per day in the fourth quarter of 1996. The LSEOR helped blow down the CPF-1 gas storage area by using more lean gas to make MI, Ma said.

The project produced an oil wedge of 12,000 bpd in 1997, a wedge expected to grow to some 40,000 bpd by the turn of the century.

First multilateral well 1996

By the end of 1996, Kuparuk tried its first multilateral well using a new approach; three multilaterals had been attempted at Prudhoe Bay, and the Kuparuk team worked closely with Shared Services Drilling to learn from that work.

ARCO-BP Kuparuk alignment

In November 1996, ARCO and BP moved to common equity on all their interests in the Kuparuk area and announced an agreement in 1997 to establish common equity in 63 leases bordering the Kuparuk River unit. The final agreement included additional acreage within the Greater Kuparuk Area.

"Kuparuk has the advantage that 95% of the field is owned by two companies," said then Kuparuk Development Manager Scott Kerr. "So, we took the position that if we align our interest across the field; cross-assign all of our acreage; agree in advance to facility access terms and some ability to go non-consent; then we won't have any more arguments over equity or agreements. We'll set everything up in advance and that's what we're doing."

A number of satellites had been identified within the Kuparuk area, and the equalized equity agreement meant that either company could move forward to explore and develop the satellites. Though the majority of the area was owned by the two companies, other companies had a smaller interest in the field and had been invited to participate in the facility sharing agreement.

The Kuparuk alignment agreement in its final stages (58.5% for ARCO and 41.5% for BP) included cross-assigned acreage, a new operating agreement and special provisions for dealing with West Sak and other heavy oil reservoirs.

Satellite development accelerated

Thus, at the end of 1996, a new era was dawning for exploratory drilling on Alaska's North Slope. It was largely fueled by targeting satellite accumulations.

"We define satellites as fields that can be developed at low cost and produced through existing North Slope facilities," Thompson told Oil and Gas Journal in 1997.

As many as 50 satellite oil fields had been mapped on the North Slope, with combined accumulations estimated at more than 1.2 billion barrels — excluding West Sak, the Alaska Spark said in December 1996.

While satellites were important, ARCO was also searching for larger accumulations with farther out exploratory wells.

"We would like to drill 10-12 exploratory wells this year in the Kuparuk and Prudhoe area," said Mike Richter, then-ARCO Alaska vice president, exploration and land, "near existing infrastructure."

Richter and his team were credited with more than a billion barrels worth of discoveries on the North Slope, and he was well known for his victory sign following an Alaska discovery.

Only one wildcat on ARCO's 1997 program was far removed from existing facilities.

"The focus won't be solely on finding very large fields," Richter said. "We'll keep looking for them, but we can have success with discovery of less than super giants."

"The North Slope is a prolific oil basin (in) which industry has traditionally explored for giant fields," Thompson told O&GJ.

"Today that's changing because our new cost structure enables us to pursue development of 100 million barrel fields in areas away from existing infrastructure. This is important because the statistical probability for finding new North Slope fields in the 100-300 million barrel range looks very promising," Thompson said.

Drilling cost goal met

By 1997 the Kuparuk drill site development team reached its long-term goal of reducing drilling development costs by 30%.

Since this quest started, the organization had taken a second look at how wells were drilled, applied some existing technologies and developed some of their own technology along the way.

Kuparuk wells were redesigned to optimize performance, maintain production rates and meet the team's low-cost, long-term goals.

"The objective was cost reduction through redesign of the wells and eliminating those things that are not absolutely necessary to develop the reserves," said Zanghi, then Kuparuk drill site development supervisor.

The size of the wells was reduced, and in some cases one string of pipe was eliminated, making completions simpler.

The cost of drilling a well was reduced from an average of $1.6 million in 1993 to an expected $1.1 million in 1997.

"We've gotten the sidetrack cost down to … close to the same cost as a workover. We can get a new well bore and direct the well to a spot in the reservoir where we really want it," Zanghi said.

Split between Kuparuk, satellites

The drilling schedule would change in the winter of 1996-97, with the first half of the year spent on Kuparuk wells and the rest of the year spent on phase 1 of West Sak and the Tabasco viscous reservoirs.

Three prospects were scheduled for exploration drilling that winter and additional 3D seismic was planned for the western area of Kuparuk and the adjacent acreage.

"Two of the major factors that are making satellite prospects acceptable are lower costs and 3D seismic," Richter said.

He pointed out that seismic before 3D had largely explored the North Slope looking for 500 million barrel or more accumulations and only lightly explored for smaller fields.

"The present cost structure and progressive attitude of the state have opened up a score of opportunities for satellite drilling," Richter added, and with success the opportunity to bring production on more quickly.

"We feel very good about our future," he said.

"We've often said that about half of the known oil resource in Kuparuk is yet to be developed," Kerr said. "An estimated 5 billion barrels of oil is in place and has yet to be exploited. That includes West Sak, but it also includes other resources that we believe to be there."

Kerr said the risk factor of bringing satellite fields online exists when the maximum capacity for handling gas and water at each facility was reached. While the facilities had room to handle more oil, several had reached the maximum capacity for handling gas and some had also reached capacity for handling produced water.

The alignment agreement provided for joint exploration and appraisal of a 580-square-mile area that included the ARCO-operated Kuparuk River unit and adjacent acreage. The agreement also allowed production of satellite oil accumulations through existing Kuparuk facilities and cleared the way for West Sak development.

"This agreement will allow us to unlock the full potential of the Greater Kuparuk Area," said Thompson. "It encourages exploration, facilitates development and maximizes use of existing facilities. When we have exploration success it will allow us to move new production quickly to market."

Tarn deemed commercial

The Tarn oil field was first deemed a commercial discovery in March 1997. Field development was estimated to cost about $150 million.

On April 30, 1997, ARCO and BP announced plans to develop Tarn oil discovery adjacent to the southwest corner of the Kuparuk River unit.

Full development of Tarn would include 40 wells from two drill sites.

West Sak production begins

Work on the West Sak field began in October 1997.

The West Sak oil field began commercial production from its first producing well on Dec. 26, 1997. Production from the well, 200 bpd, was being slowly increased and was expected to reach the project's production target of 300 bpd.

The West Sak field was a shallow viscous oil reservoir situated above the Kuparuk field. The oil was very thick and difficult to produce, with an average 19 degree oil gravity, similar to the consistency of molasses.

Fifty West Sak wells, both production and injection wells, were scheduled for completion by early 1999.

"This effort will develop 51 million barrels of new reserves and add near-term production of 4,000 bpd gross in 1998, increasing to 7,000 bpd day gross in early 1999," said Thompson.

Tarn commercial production begins

ARCO Alaska and BP said August 24, 1998, that commercial production had started from the Tarn oil field.

Tarn was producing 18,000 barrels of 38 degree API gravity oil per day from five wells and would reach production rates of approximately 25,000 bpd from 20 wells, 12 producers and eight injectors, by year-end 1998.

The field was expected to reach peak production of more than 30,000 bpd by late 1999, ranking it in the nation's top 30 producing domestic oil fields.

Tarn was a 50 million barrel oil accumulation and the second satellite accumulation to begin production in the Kuparuk River unit since December 1997.

"For the industry and the state these new satellite fields will mean new reserves, new production and new state revenue," said Kevin Meyers, the new president of ARCO Alaska. "For ARCO, Tarn is one more step toward achieving our Alaska production goal of 'No Decline After '99.'" The slogan was penned by Thompson before he was promoted within parent ARCO and left Alaska.

JUDY PATRICK

Mid-1990's photo of Mike Richter, vice president, exploration and land for ARCO Alaska and later Phillips Alaska.

Tabasco next online

Operator ARCO and partner BP announced August 27, 1998, that they had applied for state permission to begin commercial production from the Tabasco oil field, a shallow, viscous oil accumulation that overlies the Kuparuk reservoir on Alaska's North Slope.

Tabasco was discovered in 1986 during development of the underlying Kuparuk field. The test well location was later identified using 3D seismic data.

Tabasco was the second viscous oil development in the Kuparuk area, following startup of the West Sak oil field.

Test production from the single Tabasco well began May 13, 1998, and the well subsequently produced more than 2,500 bpd of 16.5 degree API gravity oil.

Following approval of commercial production by the state, Tabasco commenced production in April 1998.

Plans called for drilling up to 20 production and injection wells over the next few years with production increasing to more than 10,000 bpd in 1999.

The new field held estimated reserves of as much as 30 million barrels of oil.

"This field could be larger," said Meyers. "A 3D seismic survey indicates the Tabasco formation extends beyond the area we are now developing."

Like the Tarn and West Sak, Tabasco would be produced using existing Kuparuk infrastructure.

"Development of these viscous oil reservoirs is possible because of new, low-cost drilling and completion technologies," Meyers said.

BP buying ARCO

In January 1999 Alaska North Slope crude fetched $5.34 a barrel; by the end of the year, in December 1999, it had climbed to $19.65.

Reports of acquisition talks between BP Amoco p.l.c. and Atlantic Richfield Co. were confirmed April 1, 1999, when BP Amoco said it was buying ARCO in an all-paper transaction valued at $26.8 billion.

Part of the reason BP Amoco was so interested in acquiring ARCO was because of the assets of its subsidiary, ARCO Alaska Inc.

But there was opposition to the acquisition due to worries of creating a monopoly on the North Slope.

In the end, the opponents prevailed, and ARCO Alaska was purchased in 2000 by Phillips Petroleum (see next section, "The first decade of the 21st century in GKA" for details).

Phillips takes over; Meltwater discovered

Palm does better than expected; 4D seismic viewed as game changer, replacing four miles of Kuparuk pipeline

By KAY CASHMAN
Petroleum News

Phillips Petroleum bought ARCO's Alaska Inc.'s assets in March 2000 and named former ARCO Alaska CEO and president, Kevin Meyers, the president and CEO of Phillips Alaska Inc.

After stumbling for more than a year along a road strewn with objections from federal, state and private entities that were concerned about the concentration of North Slope assets under one company, Alaska's North Slope oil industry had taken a new path.

It was a path few could have predicted at the end of March 1999, when BP Amoco said it had made an all-paper offer of $26.8 billion to purchase the worldwide properties of ARCO, its North Slope partner and rival.

On April 13, 2000, the Federal Trade Commission announced it would approve BP Amoco's acquisition of ARCO subject to divestiture of ARCO Alaska to Phillips Petroleum, and a concurrent announcement by major present and future Prudhoe Bay owners (ARCO, BP, ExxonMobil and Phillips) that they were aligning their oil and gas interests in the giant field.

BP Amoco cited Alaska cost savings as a major outcome expected from its initial plan to purchase all of ARCO's worldwide assets. Those North Slope synergies were lost when BP Amoco was forced to agree to divest ARCO Alaska. But under an agreement between the major Prudhoe Bay owners, BP Exploration (Alaska) Inc., or BPXA, would become the sole operator of Prudhoe Bay, reducing duplicate costs by eliminating the second operator, ARCO Alaska, for the east side of the field.

Aligning the commercial interests of the field's owners eliminated the source of costly and sometimes public battles between Prudhoe Bay oil and gas interests.

Phillips completed acquisition of ARCO's businesses in Alaska in August 2000.

This was Phillips' second closing in its two-part ARCO Alaska acquisition, covering certain pipeline interests and marine assets. The first closing, which took place in April 2000, included ARCO's exploration and production assets in Alaska, adding 2.2 billion barrels of oil and gas reserves to Phillips' base.

Shortly after this closing Phillips Petroleum's newly created subsidiary Phillips Alaska Inc. had something to celebrate, announcing the discovery of Meltwater, a Kuparuk satellite, on May 2, 2000.

Phillips long presence

Phillips' presence in Alaska far predated the ARCO Alaska acquisition, however. In 1952 Phillips was the first company allowed by the federal government to explore for oil in Alaska.

Phillips had long been a presence in the Cook Inlet region, where at the time of the 2000 ARCO Alaska acquisition it operated the Beluga and North Cook Inlet gas fields.

ALASKA ANVIL

Tarn satellite field development, Drill site 2N.

And Phillips was the sole exporter of LNG in the Western Hemisphere with the Kenai Peninsula LNG complex.

In acquiring ARCO Alaska, Phillips increased its production by 75%, more than doubled its reserves and added more than 1 million acres to its exploration portfolio in the state.

Building legacy assets

Phillips said its goal in Alaska was to build "legacy assets" — high-quality oil and gas developments that had long producing lives and would provide strong financial returns.

In June 2000, Phillips Chairman and CEO James J. Mulva disclosed, in a speech in Anchorage before the Resource Development Council for Alaska, that he expected the Alaska projects under development at the time to add more than 1 billion barrels to the company's reserve base — not taking into account exploration prospects slated for drilling.

Meltwater discovery

As mentioned, on May 2, 2000, operator Phillips Alaska (and partner BPXA) said the Meltwater North 1 exploration well, about 10 miles south of the Tarn oil field in the Greater Kuparuk area, tested at 4,000 barrels per day. The prospect was estimated to contain approximately 50 million barrels of proven and potential reserves.

Phillips Alaska said a second exploration well and sidetrack, Meltwater North 2 and Meltwater North 2A, confirmed a northern portion of the reservoir.

The Meltwater discovery was made on acreage purchased in June 1998 in the state's first areawide oil and gas lease sale. Phillips Alaska held a 58.46% interest in the Meltwater North 1 well, BPXA a 41.54% interest.

KEVIN MEYERS

The Meltwater North 2 well reached 6,300 feet of measured depth, or MD, and 6,132 feet of true vertical depth, or TVD. Drilling was completed Feb. 20, 2000.

The Meltwater North 2A, the directional sidetrack from the 2 well, reached a MD of 7,350 feet and a TVD of 5,770 feet. Drilling was completed March 27, 2000.

Depth information for Meltwater North 1 was later released by the Alaska Oil and Gas Conservation Commission to be 6,122 feet MD and 6,121 feet TVD.

AOGCC said the Meltwater pool discovered by Meltwater North 1 occurred in the Bermuda interval of the late Cretaceous-aged (Cenomanian-Turonian) Seabee formation.

Phillips Alaska said when it returned to the Tarn area in 1997 to drill the Tarn discovery well, it acquired extensive 3D seismic over Tarn and prospects to the south, including Meltwater.

Fourth Kuparuk satellite

Phillips Alaska said that Meltwater had the potential to become the fourth Kuparuk satellite field to begin production. (West Sak began production in 1997; Tarn and Tabasco in 1998.)

"State areawide leasing and the application of advanced 3D seismic technology made this discovery possible in less than one year," said Mike Richter, then-vice president of exploration and land for Phillips Alaska and formerly for ARCO Alaska.

"This is Phillips Alaska's first discovery as a new company and the first discovery this century for the state of Alaska," said Richter.

Production grows in 2000

In a presentation to the Anchorage Chamber of Commerce on Nov. 27, 2000, Meyers said ARCO Alaska's goal of "No decline after 99" would soon be met, largely thanks to the addition of the new Alpine field's production which had reached 45,000 barrels a day, on its way to 80,000 barrels a day by year end 2000.

In 2000, Phillips would average 355,000 to 360,000 barrels of oil equivalent a day, he said. In 2001 that would grow by about 40,000 bpd, coming close to 400,000 bpd, "a step change, in large part driven by the fact that the Alpine field is coming on."

But Alpine was only one part of the company's strategy to grow production. Phillips would use four strategies, he said.

In its existing fields, miscible injection enhanced oil recovery would be expanded. For example, four more drill sites would be added to the Kuparuk EOR in 2001 and three more drill sites in 2002, on top

Meyers names team

Several members of the former ARCO Alaska Inc. executive team were among the members of the Phillips Alaska Inc. executive team named by Phillips Alaska President Kevin Meyers May 30, 2000, including Ryan Lance, who today (Dec. 13, 2021) is parent ConocoPhillips' chairman and CEO.

In 2000, Lance who was ARCO Alaska's vice president for the western North Slope, would remain in that position for Phillips Alaska. The western North Slope asset area included the Alpine oil field and any future discoveries within the National Petroleum Reserve-Alaska.

Joe Leone would also continue as vice president of the Greater Kuparuk Area (GKA) and Cook Inlet. The GKA consisted of the Kuparuk, Tabasco, West Sak, Tarn and Meltwater oil fields.

Leone had begun his ARCO career in 1984 as a senior engineer with ARCO Exploration and Production Technology in Plano, Texas.

Mike Richter would also continue as vice president of exploration and land, responsible for oil and gas exploration and lease acquisition and management in Alaska.

Richter joined ARCO in 1977 and held exploration and supervisory positions with the North American producing division, ARCO Exploration Co. and ARCO International Oil and Gas Co.

Other ARCO Alaska team members that Meyers named to the Phillips Alaska management team included: Meg Yaeger as vice president of pipelines, who would assume oversight of Phillips' interest in the Prudhoe Bay unit upon completion of the transition to single operator; Steve Butterworth, vice president of finance, planning and control; and Bob McManus, vice president of tax and external affairs.

—Kay Cashman

of the 24 drill sites where Kuparuk EOR was already underway.

Infield and peripheral drilling would continue, as would Kuparuk gas handling expansion, coiled tubing drilling and Prudhoe Bay reservoir pressure support.

Satellite development would include bringing on new satellites, Meyers said, including Meltwater which would begin producing in 2002.

At West Sak, where the company said there were 16 billion barrels of heavy oil in place, Phillips Alaska was drilling horizontal multilateral wells and had three recent wells producing 800 barrels a day compared to previous wells in the field which averaged 180 barrels a day, Meyers said.

There were some questions that remained to be answered at West Sak, Meyers said: "Will the rates stay up? What happens when water breaks through?"

In 2001 Phillips planned six multilateral wells at West Sak and 12 injectors. "And if that works well, we eventually want to beef this up to where we have two rigs working fulltime on the West Sak, developing the core area," believed to have 400-500 million barrels of recoverable oil.

Another part of Phillips Alaska's growth strategy was exploration. The company's exploration team had a proven track record, Meyers said, with 15 reservoirs confirmed in the 1995-2000 period and 1.2 billion barrels of oil equivalent gross reserves found with a finding cost of 67 cents a barrel.

Palm discovery 2001

Next, Phillips Alaska and BPXA announced a discovery May 18, 2001, at their Phillips-operated Palm 1 exploration well. The accumulation was estimated to contain 35 million barrels of recoverable reserves.

Palm 1, drilled by Nabors Alaska 19E, found 30 feet of oil-saturated Kuparuk formation sandstone at approximately 5,800 feet subsea. A sidetrack well, Palm 1A, tested at an unstimulated rate of about 2,500 bpd of American Petroleum Institute, or API, 26-degree gravity oil.

The Palm accumulation was about 3 miles west of the Kuparuk River oil field in the Greater Kuparuk Area.

The companies said Palm would be developed as an extension of the Phillips Alaska-operated Kuparuk field by expanding the existing Kuparuk participating area and Kuparuk River unit.

"Putting this discovery in perspective, Palm is just another example of the kind of success we have had with satellites," Richter told Petroleum News May 18, 2001.

Meltwater development

Road, pad, power line and pipeline construction work were done for Meltwater over the 2000-2001 winter season. The field was in the southwestern portion of the Kuparuk River unit, some 27 miles from Central Processing Facility 2, or CPF-2.

Ryan Stramp, then-Phillips Alaska's Meltwater development coordinator, said Meltwater was the most distant of the Kuparuk satellites — only 10 miles from Tarn, but some 25 miles from production facilities at Kuparuk.

The company's process engineers had to determine if crude oil from the Meltwater pad "would make it on its own energy, or were we going to have to put in some pumps or some sort of processing" at the pad, Stramp said.

They decided that with a large diameter pipe at the Meltwater pad (2P) the natural energy from the reservoir would move the crude oil approximately 25 miles to CPF-2.

Stramp said 17 or 18 wells would be drilled initially, results assessed, and then the final eight or 10 wells would be drilled.

The reservoir at Meltwater was a little shallower than Kuparuk,

JUDY PATRICK

Nabors 7ES completes development drilling at Palm satellite. Photo taken in early July 2003.

about 5,200 feet, and conventional directionally drilled wells were planned.

"We've got one central pad and we're going to develop several square miles of reservoir by directionally drilling out in all directions around the pad," Stramp said.

Meltwater starts up

According to AOGCC, regular production from Meltwater began on Nov. 29, 2001, versus 2002 as expected, and peaked in May 2002 at 10,863 bpd.

At the time, Phillips Alaska said Meltwater's initial production on Nov. 29 was 3,000 barrels.

On March 27, 2001, Stramp told Petroleum News that he expected oil recovery at Meltwater was now 52 million barrels. The oil had an API gravity of 36 degrees, "which is a fairly thin, nice oil to produce," Stramp said.

Production was expected to peak at 20,000 bpd in 2002-2003.

To get 52 million barrels out of the ground at 20,000 bpd, "we're going to implement an enhanced oil recovery process from the very beginning, similar to what we did at Tarn," he said.

Alternate slugs of water and miscible gas would be injected, to "maximize recovery and rate out of the reservoir," Stramp said. Seven injectors and 21 producers were planned; over time some of the producers would be converted to injectors.

The cost estimate for the development at the time of the interview was $185 million. Phillips Alaska was the majority owner with 55.96% of the project, with BPXA at 39.75% and Unocal at 3.96% coming in second and third.

Stramp also said that there was additional exploration potential between the two satellite fields, "and we made some accommodations for that in our design."

The following winter, he said, "an exploration well may be drilled in this area and if things work out, we may have another drill site that we'll be building in between and tying into this same infrastructure."

Palm construction begins

Weather and permits came together in late January 2002 enabling Phillips Alaska to begin the construction work needed to tie in the 35 million barrel Palm accumulation at its discovery well west of the Kuparuk River unit.

Chris Alonzo, then-Phillips Alaska staff engineer in the Satellites Group, told Petroleum News Jan. 28, 2002, that construction activity kicked off that day after the company received the last of its permits for the project.

Tundra travel had been a problem because of early heavy snow cover on the North Slope, but Alonzo said the area near the coast had been cold enough that Phillips Alaska was cleared for tundra travel for the project on Jan. 24.

Palm was being developed as a single new Kuparuk Central Processing Facility 3, or CPF-3, drill site. Approximately 5 miles of pipelines and gravel road, including a bridge over Kalubik Creek, would connect the new drill site, 3S, to Kuparuk drill site 3G.

Alonzo said the cost of the project, including environmental studies, facilities construction and drilling, was about $115 million.

Gravel work, power cable

Major construction activity for Palm would take place over the next three to four months as the pipeline and road were built, followed by on-pad work and drilling beginning in October 2002.

There were two starting points for the Palm project, Alonzo said: drill site 3G and mine site F, south of 3G. Two ice roads would be built: one from the mine site for gravel hauling and one from 3G to 3S for pipeline construction.

Ice would also be put in to support bridge construction at Kalubik Creek and at drill site 3G for equipment storage. Lodging for workers was at the main Kuparuk camp.

Construction started with the power cable, which was being buried in the roadbed, Alonzo said. The power line goes in first, he said, then gravel would be placed over that and the ice road built for pipeline construction.

The vertical support members and three pipelines (water, miscible injectant and crude oil) would also be installed in the winter of 2002.

In addition to development work for the new 3S drill site, the Palm project also included extending the miscible injectant line from drill site 3G back to drill site 3F, Alonzo said, allowing MI to be injected at the 3G drill site for enhanced oil recovery.

"It's an opportunity for the project to share the costs, so it was a win-win for 3G," he said.

Module construction was expected to start in early February and the modules would go out to the pad early in the summer 2002, as soon as they were completed, while the road was still frozen, Alonzo said, to allow time for tie-in work that had to be done on the pad.

But first the road would sit over the summer, Alonzo said: "There's still quite a bit of ice in the road and we would like it to drain and not have a lot of traffic on it. So, we're planning on minimizing traffic this summer on the road."

Drilling at Palm

Once the rig had been moved out to the drill site in October 2002, drilling would begin immediately. The pad design accommodated 26 wells, but Alonzo said the current plan was for 20 wells — the exploration well plus 19 new wells. The 20 included 12 producers and eight water injectors.

The drilling pad was being built around the exploration well, Palm 1A. Alonzo said that with the Palm 1A well available, it can be brought back online as soon as the equipment and the pad are complete: "As soon as all of the on-pad work is completed, we'll bring that well on, and then each well as soon as we're finished drilling it."

Production from the 3S drill site was expected to peak at 16,000 bpd in 2003-2004.

Minimal pad layout

Drill site 3S followed the Meltwater design, trunk and lateral, minimizing the amount of acreage on the tundra, Alonzo said.

But the oil at drill site 3S was different than the oil at Meltwater.

Meltwater oil had paraffin, and because of the paraffin Meltwater needed jet pumps in the wells. The oil at 3S was a standard Kuparuk crude, he said, "so we don't have any paraffin problems."

The 3S drill site "is truly a Kuparuk extension," Alonzo said: "This is a Kuparuk sand, it's a C sand. Very similar oil qualities to the main field. Actually, a little bit improved: we are higher up structurally, so it's got a little higher API gravity than you see in some of the main Kuparuk fields."

Phillips, Conoco combine

Meanwhile, Phillips Petroleum combined with Conoco in August 2002, creating ConocoPhillips and, in Alaska, ConocoPhillips Alaska, Inc.

And a year earlier, BP Amoco plc shareholders voted to drop "Amoco" from its name, renaming the company BP plc. Its Alaska subsidiary remained BP Exploration (Alaska), or BPXA.

Palm goes online

The Palm satellite oil field went online Nov. 14, 2002, initially producing 2,350 bpd of 26-degree API gravity oil from a single well.

In early July 2003, production had gone way up. "The current oil production rate is approximately 29,000 barrels of oil per day, which exceeds pre-development expectations," then-ConocoPhillips Alaska spokeswoman Dawn Patience told Petroleum News July 9, 2003. Palm was expected to peak at 16,000 bpd in 2004, she said.

Patience said the total number of wells at the drill site was 17, including nine producers and eight MWAG injectors.

"The project came in under budget and ahead of schedule," she said.

Time from spud of the discovery well to first production at Palm was 20 months.

Looking for more

In 2004, work continued on the main Kuparuk reservoir.

Matt Fox, then the company's greater Kuparuk area development manager, said in December 2004 that a new 3D seismic survey would be shot across the Kuparuk field.

Kuparuk "is one of the most complex fields in the world from a geological perspective, from a faulting perspective — it's just incredibly complex. You combine that with the fact that we're doing a miscible gas injection enhanced oil recovery. You can't go many places in the world and find anything more challenging than this," Fox said.

Because Kuparuk was so complex, there were still opportunities there, Fox said.

The 3D seismic shot in the winter of 2004-05 used "new technology that's designed to allow us to image in the reservoir where the oil and gas are" allowing the company to target sidetracks, he said.

CONOCOPHILLIPS ALASKA

Conoco Chairman and CEO Archie Dunham (left) and Phillips Chairman and CEO Jim Mulva (right).

More coiled tubing work

ConocoPhillips Alaska was also continuing to experiment with coiled tubing drilling techniques.

Coiled tubing drilling had been used successfully at Prudhoe Bay, Fox said, "but the geology at Kuparuk makes coiled tubing drilling more of a challenge."

In addition to 3D and coiled tubing, ConocoPhillips was "building a new full-field reservoir simulation model at Kuparuk," which, Fox said, was challenging "because of the complexity of the field."

JUDY PATRICK

MATT FOX

He said the combination of new 3D seismic, coiled tubing drilling and the new reservoir simulation model "are going to allow us to get the most from Kuparuk, whether it's through base management or through new development."

"We can't stop Kuparuk declining," Fox said, "but we can slow the decline down" and fill in with West Sak and other satellite developments.

ConocoPhillips Alaska had announced expansion of West Sak on Aug. 10, 2004.

"The combination of the new 3D seismic and the reservoir simulation model and well performance will let ConocoPhillips identify areas where it doesn't seem to be getting all the oil it could."

The seismic would identify opportunities, Fox said, such as an oil trap "up against the fault, and then we can take a coiled-tubing sidetrack up against that fault so that we pull the oil in."

Coiled tubing wells would also increase rates because they were drilled as horizontal sidetracks, he said.

Fox said that while coiled tubing can't achieve the lateral lengths a rotary rig can, "we don't need those lengths because it's quite a tight well spacing in Kuparuk anyway. What we need is the accuracy, the ability to see it and then get after it with the coiled tubing."

Fox said ConocoPhillips Alaska planned to put the 3D it shoots in the coming winter to work before the end of 2004 and was doing some preparatory work so that the seismic could be very efficiently processed.

Once the seismic was interpreted, he said, it would be used to identify targets for infill drilling at Kuparuk for the next several years.

ConocoPhillips Alaska told the Division of Oil and Gas that the 3D seismic survey would be 155 square miles "of full-fold data, covering nominally one-half" of the Kuparuk River unit. The company said original 3D datasets were acquired between 1988 and 1990, and as a result of the new 3D, which will have higher frequency content, closer spacing and longer offset, it expects "significant improvement in stratigraphic and structural resolution at all horizons, both producing and non-producing intervals."

Drilling work

ConocoPhillips Alaska was also drilling a sidetrack lateral on the eastern edge of Kuparuk, the 1D-30L1, from the 1D pad in ADL 25661, to test Kuparuk C4, C3, C2 and C1 sands in lease ADL-28248, outside the boundary of the existing participating area, although inside the Kuparuk River unit. The company said that if the sidetrack, being drilled as a tract operation, was successful the working interest owners would apply for an expansion of the participating area.

ConocoPhillips Alaska said it planned one-half rotary rig per year for Kuparuk drilling and workovers with five to seven new penetrations per year. Approximately five coiled tubing drilling wells were planned in 2005 and 2006, the company said, then 10 coiled tubing drilling wells per year for 2007-09, the remaining years of its latest five-year plan.

Bowles takes over in Alaska

In early October 2004, ConocoPhillips named Kevin Meyers president of its exploration and production operations in Russia and the Caspian Sea region. James "Jim" Bowles would replace Meyers as president of ConocoPhillips Alaska. The parent company said October 6 that following "a brief transition period," Meyers would be based in Moscow and Bowles in Anchorage.

JAMES BOWLES

Bowles was rejoining the company after retiring from Phillips Petroleum in 2002 with 28 years of service. He held drilling and production assignments for Phillips, was vice president of the company's gas gathering and processing subsidiary, deputy managing director of the Norway division and president of Phillips' Americas division, which included the company's Alaska operations prior to the ARCO Alaska acquisition.

Kuparuk tops 2B barrels

On July 20, 2005, ConocoPhillips said that the Kuparuk oil field produced its 2 billionth barrel of oil, which was the original recovery estimate for Kuparuk.

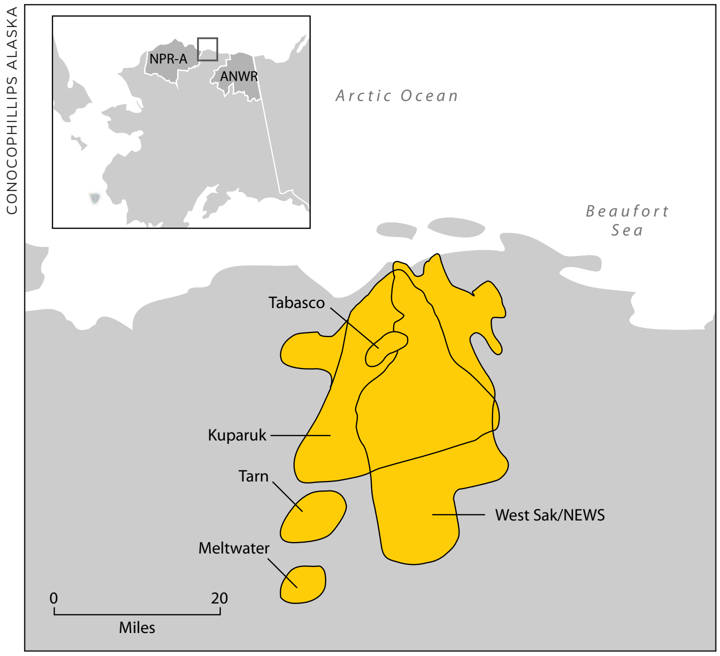
Twenty-four years after startup the field remained the nation's second largest producing oil field.

ConocoPhillips said the increase in recovery came from "improved oil recovery methods and development of innovative technology that finds and extracts more oil from the field."

The Greater Kuparuk Area also had production from Tarn, Tabasco, West Sak and Meltwater. Total production was some 185,000 bpd, of which some 140,000 bpd was from the Kuparuk reservoir.

In its 2004 annual report the Alaska Division of Oil and Gas estimated that Kuparuk and its satellites had remaining reserves of 1.617 billion barrels which the division said was based on an "aggressive heavy oil component."

The division's estimate included 960 million barrels from the Kuparuk reservoir, 530 million barrels from heavy oil at West Sak and 126 million barrels combined from satellites Tabasco, Tarn and Meltwater.



ConocoPhillips Alaska had a 55% share of the Greater Kuparuk Area. BPXA owned 39%; Unocal and ExxonMobil had smaller shares.

ConocoPhillips said that since 1981 the Greater Kuparuk Area had paid nearly $1 billion in property taxes to local and state governments and an additional $7 billion in royalty and severance taxes to the unrestricted general fund of the State of Alaska.

Kuparuk owners had invested about $7 billion in capital to develop the field.

Technology drives West Sak

It had taken a lot of technology — and a lot of money — to make some of the West Sak and Schrader Bluff viscous oil on the North Slope commercial. And more money and more technology breakthroughs would be needed to develop the shallower parts of the West Sak-Schrader Bluff accumulations and the even shallower and more viscous Ugnu.

Fox told the Alaska Support Industry Alliance Dec. 15, 2005, that it took 20 years, and $500 million in experimentation, to bring viscous development to the commercial stage at the deepest West Sak accumulations in the Kuparuk River unit. That's $500 million in addition to the $500 million in capital the field owners had just sanctioned for development of the West Sak accumulation at the 1E and 1J pads in Kuparuk.

The deeper viscous oil on the North Slope, called West Sak at Kuparuk and Schrader Bluff at Milne Point and at Orion and Polaris in Prudhoe, combined with the shallower Ugnu formation, accounted for 23 billion barrels of oil in place, Fox said: a volume of oil equivalent to the original oil in place at Prudhoe Bay.

Low rates, recovery, price

But, Fox said, the viscous oil suffered from "a triple whammy effect: you've got the low rates, the low recovery factor and the low price."

The oil wasn't just heavy oil, he said, it "is cold heavy oil, and that means it's extremely viscous."

The reservoirs were shallow, from roughly 3,000 feet below the surface down to some 4,500 feet, and they lay under some 1,800 feet of permafrost, so the reservoir temperatures varied from about 40 degrees Fahrenheit to about 90 degrees F, "and that combination of these cold temperatures and the relatively low API means that we have extremely high viscosities."

Prudhoe Bay and Kuparuk oil had about the same viscosity, ability to flow, as water, Fox said. West Sak had about the same viscosity as olive oil. Ugnu has about the same viscosity as maple syrup.

In terms of production this was a big whammy: West Sak was about 100 times as viscous as water. The flow rate of oil was "inversely proportional to viscosity, so if viscosity increases by a factor of 100, which is what we have here going from the Kuparuk to the West Sak, rates will decrease by a factor of 100."

In addition, recovery rates were lower, because the West Sak oil was very difficult to move out of the pore spaces in the formation, Fox said.

And refineries pay less for lower API oil than for Prudhoe Bay or Kuparuk oil.

Rapid changes

While the North Slope producers had been trying to make the shallow accumulations commercial for two decades, Fox said, the things that finally made the best of this oil commercial had all been recent developments, since the late 1990s.

Well types changed from vertical to horizontal multilateral; drilling reach changed from moderate to extended reach; the recovery mechanism had changed from waterflood to waterflood enhanced by lean gas injection; and the method of dealing with sand had changed.

The West Sak-Schrader Bluff and Ugnu reservoirs were unconsolidated, poorly cemented, and sand was produced with the oil.

In the late 1990s, the focus was on keeping the sand in the reservoir by using sand screens in the well bores. Fox said there were three problems with this: some of the West Sak sand was as fine as flour and you couldn't devise a screen that could keep it back; restricting sand with screens restricted the flow rate and "was exacerbating the viscosity problem"; and the screens were costly.

The solution was to focus on flow rate and deal with the sand that came to the surface by re-injecting it, Fox said.

Well spacing had also changed from 1,100 feet to 1,250 feet. It may not look like a big deal, he said, but the more distance you can put between wells, the fewer you have to drill, "And that's a big deal for pushing down the cost."

Keeping oil flowing

Another thing that had changed was keeping the oil flowing. Electric submersible pumps were used to move the heavy oil to the surface, but they broke down, and because Kuparuk didn't have a full-time workover rig, wells could be shut in for six months at a time. "And that would kill the economics of the project because of the level of the failures," Fox said.

They were still using electric submersible pumps, but by December 2005 they were building in backup: the ability to use gas lift when the pumps failed, "so we can keep some level of production going, and that made a surprisingly big difference to the economic viability."

An oil-based mud system replaced a water-based mud system for drilling, improving both drillability and productivity.

And how the oil was handled at the surface changed, he said.

The initial plan was just to mix West Sak production with Kuparuk production, since both occurred on the same drill sites, but experimentation showed that wasn't enough, Fox said, and so heaters were being added at the drill sites and chemicals were being added to allow the sand to drop out of the oil.

And drilling technology improvements increased the volume of oil that could be accessed from a single well. Extended reach multilateral wells were now possible because of "new technologies like rotary steerable systems and more efficient torque reduction tools (and) more efficient mud systems …" increasing production from some 200 bpd from 1980s vertical wells to 2,500 to 3,000 bpd from long tri-lateral wells, Fox said.

Waterflood plus gas

With waterflood, they were able to get more of the viscous oil from the rock pores: a recovery rate of some 18% was possible, Fox said.

In the deeper North Slope conventional oil reservoirs miscible gas injection was used for enhanced oil recovery, a type of gas injection where the gas injected mixes with the oil in the reservoir.

But viscous oils "don't lend themselves to a miscible process," Fox said, so instead of miscible gas, lean gas would be used. This was in pilot testing in December 2005, he said.

The gas doesn't mix with the oil, but "some molecules in the gas link to the oil and very little exchange is enough to drop the viscosity dramatically," for example from 60 centipoise (centipoise is a measure of viscosity) to 10 centipoise, which produces "a significant increase in the displacement," Fox said.

The expected increase in recovery with lean gas injection was 20% over waterflood, increasing total recovery to about 22%.

Slope-wide sharing

"The only way we were really able to exploit these technology advantages is because we made a concerted effort to share knowledge across the Slope and within the operating companies," Fox said, and called the level of knowledge sharing "unprecedented."

The North Slope viscous team included technical staff from ConocoPhillips Alaska and BPXA, with some ExxonMobil participation.

One thing the team was asked to do was to improve their ability to predict rates. "We had a track record of over-promising and under-delivering and it was killing our creditability outside Alaska when we would go looking for funds."

Sand control was another issue the viscous team tackled, as was depletion planning, getting the oil out of the ground, "and that team came up with the idea of doing viscosity-reduction gas injection," Fox said.

The North Slope viscous team was continuing to work, he said, learning from implementations and looking at what could be done next.

What about the rest?

Of the 23 billion barrels of heavy oil in place, some 15-16 billion barrels are at Kuparuk, with 1C and 1D, the experimental pads, developing about half a billion barrels and the 1E and 1J pads exploiting oil in place of about a billion barrels.

"And that same technology that we've unlocked for 1E and 1J, we can apply to somewhere between another 800 million to a billion barrels," Fox said.

But technology breakthroughs "will be required to unlock the rest of the potential because once you move out of that eastern part of the West Sak, the viscosity's too large to use the technology that we have," Fox said.

The drilling technology can be used, "but not the recovery mechanism, not waterflood, you can't effectively waterflood."

It will take new technologies, he said.

The exotic "fish bone" wells drilled in Venezuela's heavy oil fields work because that was primary depletion only, the oil was too viscous for waterflood: They were pumping out the 10% they could get with primary depletion and leaving the rest in the ground, Fox said.

At West Sak, with waterflood, wells had to be in straight lines for efficient waterflood sweep.

The exotic wells might be a possibility, he said, in shallower portions of West Sak or for the Ugnu, if primary depletion were to be used there.

Steam assisted gravity drainage, used in Canada, wouldn't work for the West Sak because the sands are too thin, but it might work in the thicker Ugnu formation, and "we're running laboratory experiments and reservoir simulation experiments to try and see if we can make this viable," Fox said. "But there are some big challenges in this environment: we have 1,800 feet of permafrost (and) pumping steam through that — that has to be thought through."

The technology advances that allowed 1E and 1J to be commercial "have been rapid and they've been dramatic," Fox said. "The knowledge sharing across the Slope … — and across the world in fact — has been very leveraging …

"And we're actively working on the next technology breakthrough we need to get to the even more viscous stuff," Fox said.

Busy times in 2006

To stem the decline in North Slope oil production ConocoPhillips Alaska was forging ahead on three fronts in 2006:

- Developing new satellite fields near the Alpine field.
- Developing viscous or heavy oil in the central North Slope.
- Exploring for new oil fields.

That was the message that Bowles delivered at the Alaska Support Industry Alliance's Meet Alaska conference on January 20, 2006.

"We offset (production decline) with continuing investments in our work on the Slope," Bowles said.

Much of what he talked about dealt with ConocoPhillips Alaska's westward expansion to Alpine and into NPR-A, but Kuparuk and its satellites were not ignored.

Bowles said the company had started up production from the viscous oil West Sak accumulation from the Kuparuk unit 1E pad in 2005

Long West Sak saga

1971 West Sak discovery
early 1980's West Sak pilot project
1997-1998 Conventional vertical wells
1999-2000 First multilateral wells
2000-2005 Development optimization
1J pad development

and from the 1J pad through the end of the year. The company expected ultimate peak production upwards of 45,000 bpd from West Sak.

Bowles said that ConocoPhillips Alaska would be participating in seven exploration wells on the North Slope that winter — he included three West Sak-equivalent viscous oil wells in that count.

He said that success with drilling for viscous oil could lead to some major new development, including an Orion I-100 well it was doing with BPXA.

"If we can have some success drilling those, it could spin off a future large project development for this West Sak viscous oil," he said. "So, it's going to be an important season for us as far as what we see on the exploration front."

In addition to new development and exploration, the past few years had seen a major increase in well work in existing fields, Bowles said. And that trend looked set to continue.

2006 "will be the biggest year we've had in Kuparuk since the early '80s," Bowles said.

Bowles particularly pointed out that an increase in the use of coiled tubing drilling in field development was helping maintain production rates.

"Kuparuk set a world record of an 18,000-foot plus departure with 2-inch coiled tubing," Bowles said.

ConocoPhillips Alaska's North Slope workload was particularly high at the time — Bowles estimated that it would require about 2.2 million manhours just in construction work in 2006. That was a 50% increase from 2004 in direct manhours on construction projects, he said.

"This just goes to show that there's a lot of activity on the Slope in trying to continue development of reserves," Bowles said. "… It's going to be a very busy year for us in '06."

West Sak output late 2006

In late 2006 there were 65 West Sak wells at Kuparuk drill sites 1B, 1C, 1D, 1E and 1J.

AOGCC records showed 25.9 million barrels produced from West Sak through the end of November 2006, with 490,616 barrels produced in November, an average of 16,355 bpd from 36 producing completions.

Total Kuparuk River field production for November was some 4.4 million barrels, so West Sak accounted for 11% of Kuparuk production in November 2006.

Still investing in 2007

ConocoPhillips Alaska's capital investment looked to remain steady at about $800 million for 2007. That was one of the messages delivered by Randy Limbacher, the parent company's vice president for exploration and production-Americas, at the annual Meet Alaska conference on January 19, 2007.

But rising costs meant "we don't get quite as many projects in for the same amount of dollars," Limbacher said.

That $800 million compared with ConocoPhillips' $12.5 billion of upstream capital investment worldwide.

The state held about 2 billion barrels of the company's worldwide proven crude oil equivalent reserves of 11.4 billion barrels in 2006, he said.

ConocoPhillips Alaska produced more than 300,000 bpd of ConocoPhillips' total crude oil production of 2.4 million to 2.5 million bpd.

ConocoPhillips Alaska's North Slope capital projects continued to consist of development drilling at Kuparuk and Prudhoe Bay; the development of heavy oil at West Sak; and the development of the Alpine field satellites.

Limbacher said the Kuparuk 1J development at West Sak was more than 50% finished and should be finished in 2008.

"We're currently evaluating the next development phase within the Northeast West Sak area," Limbacher said.

Continuing North Slope exploration also figured large in ConocoPhillips' capital expenditure, but none of those wells were in or near the Greater Kuparuk Area, and the only 3D seismic would be shot in the Chukchi and Beaufort seas, Limbacher said.

ConocoPhillips saw an increasingly difficult worldwide business climate, he said, with much of the world's petroleum resources only available to state-run oil companies.

At the same time, taxation on the oil industry had been increasing.

"The type of (fiscal) terms that we have available to us to pursue oil and gas projects have changed quite a bit," Limbacher said, citing Alaska's change to PPT, the then-new oil and gas production tax, as an example of an increased burden on industry.

In addition, shortages of skilled labor were pushing up labor costs. And taken together, many of the changes in the business environment were rolling up into an overall increase in the oil industry cost structure, he said.

4D shows promise

Drilling a wildcat exploration well had always been a risky proposition.

And even drilling a well within a known oil field involved some level of uncertainty about what was under the ground.

But advances in seismic surveying and data processing over the past few decades had refined the identification of what geophysicists called "direct hydrocarbon indicators" to a point where that drilling risk may at least be reduced, given an appropriate geologic situation.

Another technique with the potential to detect underground hydrocarbons, at least in the context of an operational oil field, was known as 4D seismic. This technique involved 3D seismic surveys over the same area over a time period of perhaps several years (a 3D survey is a type of survey that results in a three-dimensional image of the subsurface geology). Changes in seismic signals from one survey to the next could provide insights into the movement of fluids such as oil and gas within the field reservoir.

As a technique, 4D seismic was still relatively young in 2007, although results so far showed promise, Jon Anderson, then-chief geophysicist, exploration and land for ConocoPhillips Alaska, told Petroleum News.

"It's going to be huge as far as economics goes, because then you're looking for unswept oil, changes in gas caps, watching waterflood movements," Anderson said of 4D seismic.

Because changes over time in the seismic signals could result from a variety of causes, such as the gas coming out of solution or subsurface pressure changes, the linking of the seismic data to field reservoir data formed a critical component of 4D analysis, he said.

But given that linkage, it was possible to use 4D seismic to test predictions that reservoir engineers made about reservoir fluid movements in response to field production.

"That's the beauty of 4D," Anderson said. "You know that the fluids are there, and you know they're moving, and you integrate that with all the reservoir information."

But onshore 4D surveying was still in its infancy in 2007 and had yet to be fully proven to work, Jon Konkler, then-senior development geophysicist for BPXA told Petroleum News. Still, he saw the use of 4D surveys as a "game changer."

4D surveys had been done in both the Kuparuk and Prudhoe Bay fields, Anderson said.

Tarn slowing down

Exploration at Tarn began with the Bermuda 1 well drilled in 1991 and the Tarn 1 well drilled the following year.

Using data from a seismic survey conducted in early 1996, ConocoPhillips drilled four delineation wells in the winter of 1996 and 1997, finding a Brookian oil reservoir. The company gathered additional seismic data over the following two winters.

According to state figures from July 2007, the field was believed to contain 41 million barrels of remaining recoverable oil reserves and 50 billion cubic feet of remaining recoverable natural gas reserves.

The Kuparuk River unit was expanded in July 1998 and the Tarn PA formed. By the end of 2006, ConocoPhillips had drilled 45 wells from two drill sites at Tarn.

Through November 2007, the field had produced 85.5 million barrels of oil, making it the second-most productive participating area in the Kuparuk River unit.

Production at the Tarn oil field peaked in 2003 at 33,842 bpd.

By the end of December 2007 Tarn was producing just less than 15,000 bpd.

In 2006 and 2007, ConocoPhillips Alaska drilled 10 development wells at Tarn trying to hit parts of the reservoir previously thought to be uneconomic.

At the end of that time, the company told state officials it planned to continue infill drilling at Tarn.

CONOCOPHILLIPS ALASKA

West Sak pipeline construction.

Seismic contractor Veritas DGC Land Inc. applied for a state permit to acquire 200 square miles of 3D seismic survey for ConocoPhillips Alaska over the Tarn field in the winter of 2007-08.

Pushing drilling records

In 2008 drillers on the North Slope were continuing to push the technology envelope.

Precision horizontal drilling threading through thin reservoir sands was enabling high well production rates and the production of heavy oil.

Highly deviated and extended reach drilling was pushing access from single well pads to reservoir targets dispersed across wide areas of the subsurface.

And recent record-breaking drilling by ConocoPhillips Alaska exemplified this drilling trend, then-drilling engineer for the company, Dennis Hartwig, told Petroleum News in March 2008.

He said the 1J-174 D-sands well in the West Sak field had recently broken the ConocoPhillips worldwide extended reach drilling record by

CONOCOPHILLIPS ALASKA

Three rigs, two Doyon and one Nordic, drilling West Sak wells at 1J pad in September 2006.

achieving an extended reach drilling ratio of 6.05 to 1. That was close to the limits of extended reach drilling ratios achieved by anyone, Hartwig said.

The extended reach drilling ratio was the ratio of the horizontal departure of the well to the true vertical well depth. The departure was the horizontal distance measured along the well path from the well head to the bottom of the well.

The shallow West Sak reservoir required wells that would bend quite sharply between the vertical surface wellheads and the horizontal configuration of the well bores in the pay zones.

The bottom of the 1J-174 D-sand well in the West Sak was at a vertical depth of 3,055 feet, with a horizontal departure of 18,472 feet, Hartwig said.

The well trajectories also had to bend horizontally into alignment with the array of parallel well bores in the reservoir formation — the overall well pattern looked a bit like a giant grass rake, with the handle at the surface drilling pad and each prong representing an individual well.

"A lot of these wells have big sweeping turns in them to get the laterals lined up correctly," Chris Alvord, then-drilling team leader for the Alpine field, explained.

The West Sak reservoir zones that ConocoPhillips was targeting in the Greater Kuparuk Area lie a long way from the well pad — zones closer to the pad had already been drilled, Hartwig said. But to reach the more distant zones, the middle sections of the wells had to deviate very precisely to hit the required target, at the point where the horizontal well section needed to start.

"The challenge on a lot of these wells is the intermediate hole section … to land the pipe in the zone," Hartwig said. "So, we drill a long, long high angle trajectory that's starting at the surface and going out there to 3,000 feet TVD. Once we land in the zone, we set casing. That's the most difficult and challenging part of our wells."

Just to compound the technical complexities, wells like 1J-174 involved multilateral completions, in which several horizontal well sections extended from a single well bore that connected to the surface, Alvord said.

Replacing Kuparuk pipe

In September 2008 ConocoPhillips Alaska said it planned to replace more than 4 miles of pipe in the Kuparuk River unit early in 2009 to allow for better corrosion monitoring.

The replacement would allow unit operator ConocoPhillips Alaska to run smart pigs and maintenance pigs through the Kuparuk Pipeline Extension.

Pigs were mechanical devices fed through a pipeline for different purposes. Smart pigs measured damage along the walls of a pipeline, while maintenance pigs cleaned out deposits that could lead to corrosion.

The shortest of the major pipelines on the North Slope, the Kuparuk Pipeline Extension ran about 9 miles from CPF-2 to CPF-1, both in the eastern half of the Kuparuk River unit.

Originally when it came online in 1981, the Kuparuk Pipeline Extension was the westernmost piece of North Slope transportation infrastructure. In 2008, the extension connected the Alpine Oil Pipeline and fields to the west with the Kuparuk Oil Pipeline, which fed into the trans-Alaska oil pipeline.

During its first 25 years in operation, the Kuparuk Pipeline Extension moved more than 73 million barrels of sale-quality oil into the gathering facilities at Prudhoe Bay. And although the small pipeline had been a workhorse, that much oil naturally took its toll.

But monitoring the Kuparuk Pipeline Extension was cumbersome.

ConocoPhillips Alaska wasn't able to pig the above-ground pipeline because of its odd design: About half of the line was 12 inches in diameter, while the rest was 18 inches in diameter. As a result, the company could only monitor the line externally, using ultrasound equipment.

The upgrades would enlarge the narrower section, making the entire pipeline 18 inches in diameter. It also would use existing vertical support members and pipeline racks. (The old pipe was to be cleaned and recycled.)

Along with the replacement effort, ConocoPhillips Alaska planned to build pig launching and receiving terminals at either end of the pipeline. The terminals would be built in basins used for collecting snow during winter cleanups and meltwater during spring break-up.

The company said it expected to finish the entire project by the fall of 2010.

Cuts 20% for 2009

The spending plan released by ConocoPhillips for 2009 cut capital spending in Alaska by 20%.

The company's plan specifically mentioned a focus on "continued development" of the Kuparuk and Prudhoe Bay units, and the Alpine field and satellites, but left out the West Sak heavy oil deposit, which had been included in previous annual budgets.

"We have slowed work at West Sak," then-ConocoPhillips Alaska spokeswoman Natalie Lowman told Petroleum News, adding that the sharp decline in oil prices over the past few months forced the company to focus on "high-margin light oil." (In June 2008 North Slope crude was $125.77; by Dec. 22 of that year it had plunged to $25.81.)

NEWS PA approved

On May 29, 2009, the Alaska Division of Oil and Gas approved a new participating area at Kuparuk called the Northeast West Sak PA.

The new PA included portions of three state oil and gas leases within the Kuparuk River unit, some 2,688 acres. The NEWS PA included acreage overlying the West Sak and Ugnu formations six miles northwest of the existing West Sak PA.

The state approved formation of the West Sak PA in 1997 and expansions of that PA in 2004 and 2007.

The NEWS PA, however, was separate from the existing West Sak PA.

"Lack of communication between the NEWS PA and the WSPA warrants a separate participating area," the division said.

Operator ConocoPhillips Alaska had already completed three wells in the proposed NEWS PA as unit tract operations and the division said confidential information submitted by the company indicated the West Sak reservoir within the NEWS PA was capable of producing or contributing to production in paying quantities.

Drilling was from drill site 3K and production would be processed through existing Kuparuk River unit facilities.

The NEWS PA, in the northeastern portion of the Kuparuk River unit, targeted the West Sak sands and part of the West Sak-Schrader Bluff sands that occurred throughout the Kuparuk, Milne Point, Prudhoe Bay and Nikaitchuq units.

"Individual sand bodies, separated by interbedded non-reservoir siltstones and mudstones, range from a few feet to about 40 feet in thickness," the division said.

AOGCC order 406 defined pool rules for West Sak, and the NEWS PA lays within the West Sak oil pool boundary, the division said, with the stratigraphic limit of the pool defined as the equivalent of the interval between 3,742 feet and 4,156 feet measured depth in the 1971 ARCO West Sak 1.

Kuparuk's West Sak sands have reservoir depths ranging from 2,700 feet TVD in the southwestern portion of the unit to some 3,800 feet in the northeast.

The division said the eastward structural dip of the West Sak causes increasing reservoir temperatures in the east and an associated decrease in the viscosity of the oil. Reservoir temperatures range from 60 degrees F in the shallower western area to 80 degrees F in the deeper eastern area, while the API gravity of the oil varied between 10 degrees and 22 degrees and viscosity varied from about 30 centipoises to more than 300 centipoises.

ConocoPhillips Alaska drilled one horizontal multilateral producer and two supporting multilateral injection wells since February 2008 targeting West Sak sands within the NEWS PA. The production well, 3K-102, had averaged more than 1,200 barrels of oil per day. The division said the company planned to complete additional NEWS wells in 2010.

Technology key to recovering more oil from Greater Kuparuk Area

What remains is more technically challenging, more expensive to get out of the ground

By KAY CASHMAN
Petroleum News

Since its December 1981 startup through the end of 2009, the Kuparuk River field on Alaska's central North Slope produced 2.19 billion barrels of oil. Excluding satellites the Kuparuk field averaged 104,145 barrels per day in 2009.

Entering 2010 Kuparuk was the nation's third largest producing oil field behind No. 1 Prudhoe and Shell's Mars-Ursa development in the Gulf of Mexico, per Energy Information Administration ranking.

But Kuparuk like its big neighbor to the east, Prudhoe, was still in decline in early 2010.

ConocoPhillips Alaska was working to squeeze every possible drop of oil out of Kuparuk and its satellite fields — West Sak, Tarn, Meltwater and Tabasco. These satellites produced an additional 37,600 barrels per day in 2009.

As of Jan. 1, 2010, ConocoPhillips Alaska owned about 55% of Kuparuk, with BP Exploration (Alaska), or BPXA, holding 39%, Chevron 5% and ExxonMobil the rest.

Among its accomplishments in 2009, ConocoPhillips Alaska told the State of Alaska in an annual report, that it had implemented a nine-well coiled tubing drilling program generating a "peak incremental oil rate" of 4,300 barrels per day.

The company said 21 laterals were drilled and completed in the wells.

A workover program added 6,000 barrels per day.

Optimizing Kuparuk output was a delicate dance involving primary production, waterflooding, miscible gas enhanced oil recovery, and immiscible gas flooding.

To some extent, Kuparuk was dependent on Prudhoe, and this dependency likely would increase, ConocoPhillips Alaska said in its annual report to the state.

During 2009, Kuparuk imported an average of 18,391 barrels per day of Prudhoe natural gas liquids to make miscible injectant, which greatly enhanced its production.

Facing a gas problem

Entering 2010 Kuparuk faced a looming problem — insufficient gas. Field gas production was expected to decline significantly in coming years, which would leave Kuparuk short of gas for enhanced oil recovery and short of fuel for field operations.

"The most technically feasible known alternative gas source is Prudhoe Bay," said the ConocoPhillips Alaska report to the State of Alaska. Prudhoe, unlike Kuparuk, had a vast gas cap.

Gas imports from Prudhoe Bay were expected to begin around 2015.

"The plan is to utilize imported Prudhoe gas as fuel gas only and not introduce any of this gas into the production system, either by injection or in the gas lift system," the company told the state. "This is due to corrosion concerns relating to the relatively high CO2 content (10-12%) of Prudhoe gas."


JUDY PATRICK

The new Nabors rig CDR2-AC drilling at Kuparuk in early 2010.

West Sak and Tarn

Of Kuparuk's four satellites, West Sak and Tarn were the biggest producers going into 2010.

West Sak, a vast heavy oil deposit overlying the Kuparuk field, produced an average of 18,866 barrels per day in 2009, and tallied about 46 million barrels through 2009.

Waterflooding the reservoir to maintain pressure and improve sweep was the main enhanced oil recovery method used for the

West Sak oil pool, ConocoPhillips Alaska said.

Activity was more robust at the Tarn satellite, southwest of the Kuparuk River field.

Tarn produced 14,063 barrels per day in 2009 via 53 development wells on two drill sites. The field, which began production in 1999, had produced almost 100 million barrels of oil, top among the Kuparuk satellites.

"More than 15 new wells and sidetracks could be drilled as part of a future infill and peripheral development drilling program," ConocoPhillips Alaska's annual report to the state said. "Targeted areas include the thinner distal lobes that previously were considered uneconomic."

One well under consideration for 2011 "may be drilled as a horizontal well with multi-stage frac completion. This would be the first application of this technology at Tarn."

Meltwater and Tabasco

The other two Kuparuk satellites, Meltwater and Tabasco, had contributed smaller volumes of oil through the end of 2009, ConocoPhillips Alaska said.

Meltwater, about 10 miles south of Tarn, had begun production in 2001 and made 2,715 barrels of oil per day in 2009. The field had 19 wells on a single drill site, and over its lifetime had produced 14.1 million barrels.

With original oil in place of 222 million barrels, Meltwater showed a "large incremental target for additional development," the report said. A 3D seismic survey of Meltwater was completed in 2008, and "horizontal or undulating wells to help connect multiple reservoir sands will be considered."

Tabasco, a heavy oil field on Kuparuk's western flank, had 12 development wells and produced 1,948 barrels a day in 2009. Since startup in 1998 it had produced 15.6 million barrels.

Geological and reservoir simulation models would help "evaluate alternative recovery strategies and additional development opportunities" for Tabasco, which the company was waterflooding.

No exploration in 2010


HELENE HARDING

In its March 7, 2010 annual report, parent ConocoPhillips said it would not explore in Alaska in 2010; rather its focus would be development drilling at Kuparuk, Alpine maintenance and preparing for future Chukchi Sea exploration.

Helene Harding, then-ConocoPhillips Alaska vice president of North Slope operations and development, told the Resource Development Council on Nov. 18, 2010, that the company's projection in 2003 was that West Sak viscous oil production would be at more than 30,000 barrels per day by 2010.

But in September 2010 West Sak output was some 18,000 barrels per day, Harding said, noting that even with oil at $50 a barrel in 2003 the company was a lot more bullish about the future at that time than it was in 2010.

On the fiscal side in Alaska "in the last three years alone we've had three increases in our taxes and the last one, ACES, ended up … taking away our upside.

"And when you're in a risk-and-reward business like we're in, when you take away the upside it's extremely hard to compete for dollars," Harding said.

As far as the company's plans for 2010, she said safe operation was key as well as operating in an environmentally sound way.

"In addition, it's very important for us to run level and operate our fields as efficiently as we can and continue to drive costs down and out of the system."

The Alaska Department of Revenue had estimated that $40 billion in investment would be necessary to deliver projected core-field production over the next 10 years, Harding said.

"We need to look at these core fields. … That's the health of our business," she said.

At the time Harding managed the Kuparuk River and Alpine fields.

A 30% recovery rate was the original Kuparuk target, "and now it looks like we're going to be closer to about 40%. And we're continuing to work on technology and challenges to enhance that and make it even better," Harding said.

But Kuparuk was nearing 30 years of age and with many years of remaining life "we're putting investment dollars towards the maintenance of our pipelines, our wells and our infrastructure."

The company launched its first next-generation coiled tubing drilling rig at Kuparuk in May 2010 (Nabors rig CDR2-AC), Harding said.

"This rig is used for infield drilling and we are using 4D or time-lapse seismic technology to help determine areas in the field where we have leftover production," she said.

Harding said that for ConocoPhillips Alaska "to deliver the next 30 years at Kuparuk we really do need an attractive fiscal structure" because projects at Kuparuk are "going to have to compete across the United States and the world for investment dollars."

Johansen: Challenging, but not daunting

Effective April 1, 2010, Trond-Erik Johansen, previously president of ConocoPhillips' Southeast Asia Exploration and Production, was named to head ConocoPhillips Alaska, replacing Jim Bowles who had died Feb. 13 of that year in a snow machining accident.

Alaska had a world-class resource base, but production was declining, and it would take cooperation between government and industry to put more oil in the trans-Alaska oil pipeline, Johansen told attendees of the Resource Development Council's annual conference Nov. 17, 2010, in Anchorage.


TROND-ERIK JOHANSEN

Reservoirs now producing on the North Slope "are what I would call the easy oil," Johansen said.

What the companies want to produce now is "more difficult" and "more expensive to get out of the ground," he said.

West Sak, the viscous oil field overlying the Kuparuk River field, was challenging to produce.

"It takes more money; it takes more technology; it takes a lot of effort to get it out of the ground," Johansen said.

Shallower still was Ugnu, the heavy oil accumulation overlying West Sak.

"You ought to know it costs a lot of money; it takes a lot of technology; it takes a lot of patience — very, very high breakeven costs — to get this oil into the plant and out to the market," he said.

In both the West Sak and the Ugnu, however, there was "a lot of oil, billions of barrels."

It would take cooperation between industry and state and federal government, Johansen said, "and it is challenging, but it is not daunting."

Production decline

Why was production dropping in Alaska and rising in the Lower 48?

"Is it because there is no oil in Alaska? No; there's lots of oil in Alaska," Johansen said.

"It is because there was a lot of cheap oil in the Lower 48? No," he said.

In the Lower 48, oil production grew 3% from 2003 to 2010; Alaska production declined 36% over the same period, he said.

Lower 48 oil production increased when oil prices rose, powered by an increase in oil rigs operating in the Lower 48. In Alaska, however, the rig count dropped from 2003 to 2005 and had been flat ever since, he said.

And for those who said that Alaska was a mature region and that production decline was to be expected, Johansen noted that Alaska had only had serious production for a few decades, compared to Texas which had had commercial production for almost a hundred years.

Yet during 2003-2010, Texas production declined only 1%.

Turnaround ahead

Alaska needed the right environment in place for more production, "like you see today happening in the Lower 48," he said.

Johansen said he was "pretty optimistic" that there would be a turnaround in Alaska "because of technology and because of smart decisions between the industry and the state and the federal government to put the framework in place to make sure we can go after it."

But that wasn't happening yet.

ConocoPhillips Alaska had drilled at least one exploration well in Alaska every year starting in 1965, Johansen said.

"This year (2010) is the first year we didn't drill an exploration well; and we're not going to drill one next year, either," he told conference attendees.

Unlocking more oil at Kuparuk

In the first half of 2011 as debate over a new tax regime that would encourage oil company investment in Alaska was being waged in Juneau, ConocoPhillips Alaska continued to work at unlocking new resources in the Kuparuk River oil field.

But with the oil lying in two major reservoir zones — the Kuparuk A and C zones — and with a multiplicity of geologic faults fracturing the reservoir into multiple compartments, teasing as much oil as possible from the Kuparuk reservoir sands proved a significant challenge.

Although the company had used water to flush oil into production wells, the compartmented nature of the reservoir and the complexities of production from the two reservoir zones had limited the effectiveness of this conventional "waterflood" technique, Bryn Clark of ConocoPhillips Alaska told the Pacific Section, American Association of Petroleum Geologists, in Anchorage on May 10, 2011.

Multiple lateral wells were being drilled out from older well bores, with the first quadrilateral well being drilled in 2005, she said.

And in 2011 it was possible to drill lateral wells up to 3,500 feet long, with up to five laterals extending from a single parent well, Clark said. Techniques such as the use of an agitator to shake the well pipe, and the planning of a well trajectory to cause the well to slope somewhat downhill towards its end, helped drillers to maximize the length of a well, she said.

Although coiled tubing drilling initially targeted the relatively thick and straightforward sands of the C zone, ConocoPhillips Alaska was now drilling multilateral coiled tubing wells in the more challenging A sands, where waterflood techniques had proven especially difficult to apply, Clark said.

A new drill-bit steering technology implemented in 2009 had enhanced the accuracy with which a well could intercept a specific sand body. Drillers had also developed techniques for steering a drill bit through difficult underground geology, perhaps, for example, causing the bit to penetrate an unstable shale layer at a steep angle to prevent the shale from sending the bit off course.

However, in mid-2010 it was still only possible to run two types of well logs — gamma ray and resistivity logs — through a coiled tubing well.

Urgency needed

Johansen told the Anchorage Chamber of Commerce Oct. 10, 2011, that there was still a lack of urgency in the state about the need to increase production through the trans-Alaska oil pipeline.

Alaska development, Johansen said, competed poorly with projects elsewhere.

At Kuparuk, Prudhoe and Alpine, the North Slope's big conventional oil fields, the easy oil had been found, Johansen said. While those fields were very mature, there was a lot of oil left, but producing it required going into new horizons and smaller pockets, and it would take longer to produce it. The number of production drilling rigs was the same as five years ago, he said, but less and less oil was produced from each well drilled.

And 2011's spend, Johansen said, was 70% maintenance capital and 30% development capital: 10 years prior those numbers were reversed.

In 2011 the trans-Alaska oil pipeline was moving 600,000 barrels per day from the North Slope as compared to 1 million bpd in 2003, and throughput was continuing to fall, he said.

"While we can't do anything with geology or geography, can we do something with the fiscal environment?"

"I can't," Johansen said. With the progressivity element in Alaska's production tax, there was less and less profit to companies taking the development risk, he said.

Designed wells at Kuparuk

Nick Olds, then-ConocoPhillips Alaska's new vice president, North Slope operations and development, told the Resource Development Council's annual conference Nov. 14, 2011, in Anchorage that the state's oil and gas tax system must be changed to compete for investment dollars.

But he also talked about some of the opportunities that the company saw in Alaska.

At Kuparuk, he said, the company was looking at designed wells.

JUDY PATRICK

NICK OLDS

Over the last few months ConocoPhillips Alaska had implemented "what we call an octa-lateral, four laterals going out one way, four going out the other way," Olds said.

That's complex, he said, and required a technology investment.

And also at Kuparuk "the targets are smaller, they're higher risk and so we need to continue to use innovation and technology to go after them," which also required a good business climate, Olds said.

There were also opportunities south of Kuparuk, he said.

"They are some small satellite developments that are years in front of us," but required the company to ask if the size was there, if the risk was acceptable and if the business climate was there to support the work.

And heavy oil, with a billion barrels at Kuparuk, would require "significant technology to advance it. Currently there's not a commercial application to unlock that potential," he said.

Tax bill passes

Then-Gov. Sean Parnell's oil tax change, which eliminated the progressivity enacted under former Gov. Sarah Palin in ACES, Alaska's Clear and Equitable Share, and changed the way credits were offered, passed April 14, 2013.

SEAN PARNELL

The belief of the governor and legislators who voted for the bill was that because it reduced the government take in Alaska, making the state more competitive with comparable oil producing areas, it would lead to more investment by oil and gas companies in Alaska, ultimately increasing — or at least slowing decline — of North Slope oil production.

ConocoPhillips to increase investment

In an April 17, 2013 press conference after the new tax legislation passed, ConocoPhillips said it would increase its investments in Alaska.

With the improvements to the state's severance tax system, the company said it was planning new work on the North Slope, including bringing an additional rig in Kuparuk in the spring and working with co-owners on funding a new drill site (2S) on the southwest flank of the Kuparuk River unit.

Johansen called those "some examples of the activities ConocoPhillips plans to kick off in the near future" to help bolster oil production.

ConocoPhillips reported its 2012 Alaska spending at $828 million, up from $774 million in 2011, with work on the Alpine West or CD-5 development in NPR-A accounting for much of the increase in 2012.

Petroleum News reported in February 2013 that the company had applied for a U.S. Army Corps of Engineers permit to build a drill site and access road for the 2S project, which would develop a discovery ARCO Alaska made with the KRU 21-10-08 well in the late 1980s. ConocoPhillips Alaska appraised the discovery with the Shark Tooth No. 1 well in 2012.

Symbiotic relationship

On Nov. 20, 2013, Johansen said under the previous tax regime government take in Alaska, including royalties, at $100-a-barrel oil, was 79%, compared to Texas at 5% and North Dakota at 57%. And while the governor's tax bill was criticized by many Democrats, looked at competitively it was still 10-15% higher than Texas and North Dakota, both of which had growing production rates, while Alaska's production continued to decline, Johansen said.

He described the relationship between Alaska and the oil industry as symbiotic: for industry to be successful, the state needed to be successful.

Applies for new viscous development

ConocoPhillips Alaska added another project to those it announced following passage of oil tax reform by the Alaska Legislature in spring 2013.

The company said Feb. 18, 2014, that it had submitted permit applications for a development targeting the West Sak reservoir at Kuparuk River.

The new viscous oil development, 1H NEWS, Northeast West Sak, included a nine-acre extension to existing drill site 1H, which would support new wells and associated facilities.

First oil was expected in 2017 for the $450 million project, with production expected to peak at 9,000 barrels of oil per day. There would be some 150 jobs during construction.

In addition to plans for the new 1H NEWS project, Johansen said ConocoPhillips Alaska, had "also added two rigs to the Kuparuk fleet."

Alaska Oil and Gas Conservation Commission records showed 68.3 million barrels of West Sak production at Kuparuk through the end of 2013.

Appraisal drilling was done in the NEWS area, north and northwest of the core area, in 2005-06 at drill sites 1Q and 3J and from an ice pad north of drill site 1H.

A NEWS participation area was approved by the Alaska Division of Oil and Gas in 2009.

Kuparuk EUR up 76% since startup

Improved technology over the past three decades increased the amount of recoverable oil at the Kuparuk oil field by 76%, ConocoPhillips said at its analyst day on April 10, 2014.

Originally expected to recover some 1.5 billion barrels of oil, a series of technologies over the years had increased that estimated ultimate recovery figure to 2.5 billion barrels.

The technologies included hydraulic fracturing, enhanced oil recovery, coiled tubing drilling and 4D seismic.

CONOCOPHILLIPS ALASKA

Drill site 2S is the development of a late 1980s ARCO Alaska discovery that was appraised by ConocoPhillips in 2012 with the Shark Tooth No. 1 well. The new drill site is near the DS 2K pad, 1.5 miles east of the Tarn road.

"If we hadn't done that we would've run out of oil at Kuparuk back in the 1990s," Executive Vice President of Technology and Projects Al Hirshberg told analysts.

Billions of barrels left

In May 2014, Johansen said 3.75 billion barrels of conventional oil remained in the Kuparuk field, with a further 15 billion barrels of heavy oil in the Kuparuk River unit.

In 2013, Kuparuk production averaged 85,700 barrels of oil per day, ConocoPhillips said.

During that year ConocoPhillips completed a 14-well coiled tubing drilling program that generated a peak rate of 4,520 barrels per day of incremental oil. The company also completed one conventional well, its plan of development for 2014 said.

New-build rotary rig

On July 28, 2014, ConocoPhillips Alaska announced it had contracted with Doyon Drilling for a new drilling rig, Doyon 142, the first new-build rotary rig the company had added to the Kuparuk River rig fleet since 2000.

The rig was scheduled to begin drilling in early 2016.

Mike Wheatall, then-ConocoPhillips Alaska manager of drilling and wells, said the company had signed a five-year contract for the rig.

Aaron Schutt, president of Doyon Ltd., said building the rig was an opportunity to both make money for Doyon's shareholders and to employ those shareholders.

"Long-term contracts for drilling around the world are actually quite rare," Schutt said.

Wheatall said the five-year contract for Doyon 142 was the period of time Doyon considered "sufficient to justify the capital investment needed to build the rig."

Doyon said North Slope rigs cost more than $100 million.

Kuparuk expansion approved

An Aug. 20, 2015, news release from ConocoPhillips reported that the first wells were spud at the new Kuparuk River unit drill site 2S in the second quarter, with production startup expected in fourth quarter.

The company also said work was advancing at the viscous oil development 1H NEWS.

Shortly thereafter Alaska's Division of Oil and Gas approved a Kuparuk River unit expansion requested by ConocoPhillips Alaska, expanding the total size of the North Slope unit by some 2,560 acres.

Kuparuk DS 2S in production

ConocoPhillips Alaska said Oct. 12, 2015, that Kuparuk River unit drill site 2S, the first new drill site at the field in more than 12 years, was on production — under budget and ahead of schedule.

JUDY PATRICK

JOE MARUSHACK

"Drill site 2S is one of the key projects that we announced after passage of tax reform," then-ConocoPhillips Alaska President Joe Marushack said. "The $475 million project created about 250 jobs during construction with numerous contractor companies and trades involved," he said.

ConocoPhillips Alaska said that at peak production the project would produce some 8,000 bpd. The announcement said the project included 14 new development wells, a new gravel road and a new drilling site capable of handling 24 wells. The project also included power lines, pipelines and other new surface facilities.

The new drill site was near the DS 2K pad, 1.5 miles east of the Tarn road.

More 4D seismic

A major effort in 2014 was seismic acquisition.

Over the past decade, ConocoPhillips Alaska had been relying heavily on seismic information to identify potential targets for additional development within the existing Kuparuk field.

In 2014 the company completed 4D processing over a 60-square-mile area of the field and licensed a 47-square-mile speculative 3D survey in the north end of the unit.

It also undertook four seismic reprocessing efforts.

ConocoPhillips Alaska said the WBA/Kalubik Depth Migration project would "better image" the western side of the Kuparuk field. The company expected to complete the project in the third quarter.

More oil in Torok

On July 22, 2016 the Alaska Oil and Gas Conservation Commission approved a new oil pool at the Kuparuk River unit, the Kuparuk River-Torok Oil Pool.

The ruling allowed ConocoPhillips Alaska to proceed with an oil development program from the existing DS 3S and could lead to additional pads in the future.

ConocoPhillips Alaska applied for the pool in late March 2016, after several years of exploration and appraisal activity in the northwest corner of the Kuparuk River unit. The commission held a meeting in early May 2016 where company representatives provided testimony

The company originally referred to the accumulation as the "Moraine" interval, but the commission decided to name the pool after the "Torok" formation present in the region.

A development program from DS 3S could access between 100 million and 500 million barrels of oil in place, according to estimates included in the Area Injection Order. A primary recovery was expected to be approximately 5%, with certain enhanced recovery programs increasing that recovery rate to a range of 13 to 55%.

Drilling starts for IH NEWS

Drilling in ConocoPhillips Alaska's1H NEWS development in the Kuparuk River unit began the week of Aug. 7, 2017, then-company spokeswoman Lowman told Petroleum News.

The new development targeted the production of viscous oil from the northeastern sector of the West Sak formation in the unit, using wells drilled from the Kuparuk 1H drill site.

The $460 million project was still expected to result in peak production of 8,000 barrels of oil per day. First oil from the development was planned for late 2017, Lowman said.

The development has involved the construction of a nine-acre extension to the existing 1H site, as well as surface facilities to support four new pentalateral production wells and 15 injection wells, Lowman said. The surface facilities included a new pipe header, wellhead infrastructure, modules, tanks and tie-ins to the existing pipeline infrastructure.

A pentalateral well has five lateral wells extending horizontally from a main well bore.

Retrieving difficult-to-flow viscous oil from the unconsolidated sands of the West Sak was challenging. Over the years ConocoPhillips Alaska had honed the techniques required for viable viscous oil production.

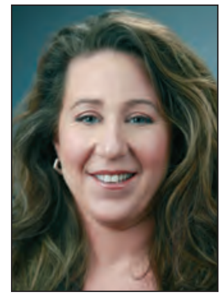
Techniques that originally involved the use of hydraulic fracturing combined with downhole pumps had evolved over the years into an approach in which multilateral, horizontal production wells thread through the reservoir sands and in which downhole pump designs had evolved. Injector wells drove oil into the producers.

Water had been used as the injection fluid, although in 2016 ConocoPhillips obtained approval from the Alaska Oil and Gas Conservation Commission for the use of a viscous reducing water-alternating-gas injection technique.

Given the technical difficulties involved in viscous oil production, economically viable production was challenging in an era of relatively low oil prices. However, ConocoPhillips and the other Kuparuk working interest owners felt confident that the 1H NEWS development would prove profitable.

"Despite low oil prices, this is a project that ConocoPhillips and its co-owners believe is a viable investment," Lowman said.

First oil at NEWS


LISA BRUNER

There was tremendous opportunity for ConocoPhillips Alaska on the North Slope, but there were challenges and capital was scarce, Lisa Bruner, then the company's vice president of North Slope operations and development, told the Resource Development Council's annual conference Nov. 15, 2017, in Anchorage.

An example of both opportunity and challenge was 1H NEWS, the Northeast West Sak development at 1H pad in the Kuparuk River unit. The company took the opportunity of the conference to announce the startup, on Nov. 4, 2017, two months early, of viscous oil production from 1H NEWS.

Bruner said 1H NEWS, which involved in-fill wells in the West Sak field, was sanctioned in 2015. But in 2016, when oil dropped to $28 a

WENDY MAHAN, COURTESY OF CONOCOPHILLIPS ALASKA


Caribou graze the tundra in the Kuparuk River unit, with Central Processing Facility 2 in the background.

barrel, the project was significantly challenged, was put on hold and teams working on it went back to the drawing board.

She said ConocoPhillips went back to work on the project early in 2017, with facilities installed through the last winter season and drilling beginning in August.

The 19-well development, with four producers, cost some $400 million to develop and involved a 9.3-acre expansion of the existing 1H drilling site.

"1H NEWS is an exciting project for us," Marushack said in a press release.

"Viscous oil is more challenging to produce, but state-of-the-art technologies are allowing us to pursue projects like this that put more oil in the pipeline."

He called the project another example of what the company does well, "bringing good projects online safely with new production and revenues for Alaska."

It was the largest investment in viscous oil at Kuparuk since 2004.

Horizontal multilaterals

1H NEWS would be developed with horizontal multilateral wells supported by vertical injectors.

Bruner said the first pentalateral well was online at 1H NEWS and was the first rotary-drilled pentalateral with access to all laterals, provided through junctions installed at each lateral which gave the company access with coiled tubing drilling to clean out any sand which accumulated over time.

The well was still cleaning up, Bruner said, but was likely to be the highest producing well out of West Sak. There were a couple of historic West Sak wells that peaked at more than 5,000 bpd, she said, and the new pentalateral was believed to be on its way to that, with more than 29,000 feet of horizontal section.

Legacy fields

At a Nov. 8, 2017, ConocoPhillips analyst and investor meeting, Al Hirshberg, then ConocoPhillips executive vice president of production, drilling and projects, said the company was undergoing a renaissance in legacy assets in Alaska, with increased capital to pursue infrastructure-led programs around the company's core position.

Bruner called the company's legacy fields its bread and butter and said while they were not easy fields to run because of aging infrastructure, they provided needed infrastructure for infill drilling and optimization.

She said coiled tubing drilling at Kuparuk accounted for more than 22% of production there, some 19,000 bpd, with 130 CTD wells drilled since 2009.

The company was also seeing results from rotary drilling, with two of the longest wells at Kuparuk, more than 25,000 feet lateral.

Kuparuk sees 2017 bump

Despite an overall reduction of development activity, ConocoPhillips Alaska experienced a notable increase in oil production at the Kuparuk River unit in 2017.

The second most productive unit in Alaska produced 109,100 barrels per day in 2017, up from an average of 103,000.

The main Kuparuk oil field produced 84,100 bpd in 2017, up from 78,100 bpd in 2016. The remaining oil production came from the four Kuparuk satellites, although only the West Sak satellite reported a slight increase in 2017.

Moving from diesel to gasoline

In early 2018 the state approved plans by ConocoPhillips Alaska to install two new gasoline tank skids and other equipment at the Kuparuk River oil field.

The division said the tanks would provide gasoline fuel for vehicles as ConocoPhillips "transitions away from diesel-powered pickup trucks in the Kuparuk field."

Water injection for Meltwater

In April 2018 AOGCC approved a request from ConocoPhillips Alaska to change to a new technique that would increase oil production at the Meltwater field in the Kuparuk River unit.

The commission issued an area injection order allowing the company to inject seawater and produced water into the oil reservoir for the satellite, agreeing that water injection would increase ultimate recovery from Meltwater.

ConocoPhillips Alaska was injecting natural gas into the reservoir to encourage oil production. However, that resulted in an increasing gas to oil ratio in the produced fluids. In addition to impacting the oil production at Meltwater, a test performed in 2017 showed that the high ratio had been causing the backing out of 900 barrels per day of production elsewhere in the unit, the commission said in its order.

The company wanted to switch to water injection by converting the gas line to Meltwater, between the Meltwater pad and the Kuparuk 2N pad, for the carriage of water.

Modeling indicated that low pressure waterflood would increase ultimate oil recovery by 1 to 2%, ConocoPhillips told AOGCC.

The use of water injection should extend field life by five to 10 years, the company said.

Coring up Kuparuk

ConocoPhillips and BP said July 3, 2018, that ConocoPhillips was acquiring BP's 39.2% interest in the Greater Kuparuk Area and BP's 38% interest in the Kuparuk Transportation Co., including the Kuparuk Pipeline, which moves oil to the trans-Alaska oil pipeline.

At the same time ConocoPhillips was selling BP a subsidiary with a 16.5% interest in the Clair field in the United Kingdom.

Excluding customary adjustments, the transaction prices were expected to be cash neutral to both companies. (Various regulatory approvals were required and received.)

"These transactions are significant for ConocoPhillips because they continue our strategy of coring up our legacy asset base in Alaska, while retaining an interest in the

Clair Field in the U.K.," said ConocoPhillips Chairman and CEO Ryan Lance. "We have a long history of creating value in Alaska and an ongoing commitment to invest in our legacy assets … Likewise, we are committed to maximizing the value of our assets in the U.K. North Sea, including continued investment in our operated assets in the Central North Sea," Lance said.

RYAN LANCE

ConocoPhillips Alaska was already the majority working interest owner at Kuparuk at 55.3% followed by BP at 39.2%, Chevron at 4.9% and ExxonMobil at 0.6%, giving the company 94.5% at Kuparuk once the deal with BP closed.

Second NEWS phase

ConocoPhillips Alaska's success with North East West Sak, or NEWS, led it to plan an expansion into a second phase of development called Eastern NEWS, scheduled for startup in 2023.

Michael Driscoll, then-ConocoPhillips Alaska's supervisor of viscous development, said in an interview in early September 2018 that the company's latest West Sak development in its NEWS project boasted five horizontal producing legs, each about 7,000 feet in length that fed oil into the vertical well was now producing about 10,000 bpd with three producers currently online. A fourth well would start producing in mid-September 2018, which would boost output.

ConocoPhillips Alaska had estimated peak production at 8,000 bpd initially.

Driscoll said the higher production was a result of better-than-expected reservoir performance and growing experience in working with the reservoir. ConocoPhillips Alaska had also reduced the cost of the project by 45%, he said, through aggressive efforts at cost-cutting and managing development more efficiently.

JUDY PATRICK

Drilling at 1H NEWS in 2018.

The lower production cost was the result of a concentrated effort to cut West Sak expenses after oil prices plummeted in 2015. NEWS was just beginning development then, "but management halted the program and told us to find ways to cut costs," Driscoll said.

The team got creative. Among several measures, water-based drilling fluids were substituted in the plan, for at least some wells, in lieu of more expensive oil-based drilling fluids. This change was made after the company determined the water-based fluid could be as safe and effective as oil-based fluid.

These steps made ConocoPhillips Alaska more confident it could put viscous into the company's long-term North Slope development plans.

The company new phase, Eastern NEWS, would be in an adjacent area.

Driscoll believed the same kind of incremental technical leaps that had made West Sak viscous oil economically viable could be applied at Ugnu, the huge heavy oil resource that has also been identified in the Kuparuk area. Ugnu oil is even thicker and more difficult to produce.

In June 2019 ConocoPhillips Alaska made public its agreement to purchase 100% ownership in the North Slope Nuna prospect from Caelus Natural Resources.

Five miles southwest of the Oooguruk unit and just east of the Colville River within the northern section of the Colville-Kuparuk fairway, the Nuna prospect included 11 tracts covering 21,000 acres.

As a result of the Nuna No. 2 discovery well drilled during the 2012-13 winter drilling season, former operator Pioneer Natural Resources increased its estimate of the areal extent of and ultimate oil recovery from Nuna, a Torok formation prospect in the Brookian sequence, to between 75 million and 100 million barrels of oil.

A Caelus spokesman in 2017 said that Nuna could result in production of some 25,000 bpd with a field life of 20-30 years.

In its June 17, 2019, announcement of the acquisition, ConocoPhillips Alaska would appraise Nuna over the next several years, with a goal of making a final investment decision.

"This transaction represents an attractive addition to our expanding North Slope position and will allow ConocoPhillips to cost effectively develop Nuna utilizing Kuparuk River unit infrastructure," Marushack said.

"We believe this acquisition could lead to more oil production, more revenue for the state and more jobs for Alaskans."

Hatfield on Nuna

During a conference call on July 30, 2019, Michael D. Hatfield, ConocoPhillips president for Alaska, Canada and Europe, provided what he described as a "little bit of color" on the Nuna prospect.

"It's a discovered resource on 21,000 acres that's in our backyard. It's immediately adjacent to Kuparuk. … It's $100 million for a 100 million barrels. It's something we're very pleased about. It will be developed from pads both that exist at Kuparuk and a pad at Nuna where there is … already a gravel … road to that pad in place," Hatfield said.

"The remaining facilities at Nuna can be built in a single ice road season. So, we'll have appraisal over the next couple years and target first oil in the 2022 timeframe," he said.

MICHAEL HATFIELD

"The development will be using existing drilling and completion technology and then the development itself will be incorporated as part of our Kuparuk program, so it won't be incremental to that," Hatfield said.

The June 2019 leasing report from Alaska's Division of Oil and Gas showed working and royalty interests in Nuna prospect leases being transferred from Caelus Natural Resources to ConocoPhillips Alaska.

West of the central North Slope, Nuna lies immediately south of the Eni-operated Oooguruk unit and immediately west of the ConocoPhillips-operated Kuparuk River unit.

Core fields rival newbies

In his presentation at the Resource Development Council's annual conference in Anchorage in November 2019, Scott Jepsen talked about the North Slope's reemergence as an oil province due to big new oil discoveries at Willow and Pikka, expanding the depiction of the renaissance by adding the North Slope's three major producing, or core, fields -- Prudhoe Bay, Kuparuk and Alpine/Colville River -- to the new fields.

SCOTT JEPSEN

Furthermore, Jepsen, who then was a senior vice president at ConocoPhillips Alaska, said that the capital investment planned for the three core fields in the next 10 years rivaled that proposed for new discoveries -- $11 billion for the core fields compared to $13 billion.

And while the three older core fields were "not the shiny new toy out there that gets so much attention," they were vital to present and future oil production in Alaska, he said.

At the time the three core fields yielded 80% of the oil production that was coming from the North Slope, Jepsen said. It was "critical that the infrastructure that these fields support stays healthy," because "the economics of the new fields are reliant" on the continued health of the core fields.

And then came Covid-19

In the face of plunging oil demand and price and the advent of the coronavirus, Alaska giant ConocoPhillips said March 18, 2020 that it was taking a long-range approach and sticking to its current 10-year plan with a mere 10% cut.

The company was reducing capital spending just $700 million worldwide from a $7 billion budget, including about $200 million in Alaska and $400 million in the Lower 48 states.

In an investor's market update conference call on March 18, 2020, ConocoPhillips said it would trim drilling programs in the Kuparuk River unit and the western North Slope Alpine area, including the laying down of two rigs.

"Our industry is clearly experiencing an unprecedented event brought about by simultaneous supply and demand shocks," top company exec Lance said in the conference call.

"The actions we are now taking reflect an acknowledgement of current events as well as uncertainty around the timing and path of a recovery."

Taking methodical approach

Lance said ConocoPhillips was in a strong position to take a methodical approach, as it ended 2019 with more than $14 billion in liquidity, including cash, cash equivalents, short-term investments and availability under the company's revolving credit facility.

"We continue to monitor market conditions and consider various scenarios to inform any future actions. We have a significant level of flexibility between our capital, operating costs and share repurchase program, but we are choosing to exercise only a portion of it at this time. We believe that the highest-value longer-term response is price-path dependent," he said.

"If anything, I think we have a greater conviction around our 10-year plan because it really is a philosophy of how to run an E&P business in a volatile market environment," Lance said.

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The company would focus on lowering costs and engaging stakeholders and would also resume regular development drilling, as well as progress on $1.1 billion in projects across the North Slope: Greater Mooses Tooth No. 2 construction, Alpine expansion, Willow permitting, Nuna development and ongoing work at the Eastern NEWS (North East West Sak) at the Kuparuk River unit.

Demobilizes rigs

On April 8, 2020 ConocoPhillips said it was demobilizing its North Slope rig fleet and ceasing exploration in the National Petroleum Reserve-Alaska.

"Due to the heightened Covid-19 risk to our North Slope workforce, we are taking action to significantly reduce the number of personnel on the Slope in a managed fashion," Lowman told Petroleum News. "To do this, we are making the difficult decision to demobilize our rig fleet. Given the high degree of uncertainty on how the situation plays out, we can't say how long these measures will be in place."

Indefinite Suspension of Meltwater

When it filed plans of development in June for the five Kuparuk River unit participating areas, ConocoPhillips Alaska told Alaska's Division of Oil and Gas that it planned to indefinitely suspend the Meltwater participating area, drill site 2P, in 2021.

The company cited low production at Meltwater, and back-out issues at CPF-2 which were estimated to cost some 600 bpd of production due to water cycling requirements to keep the Meltwater crude oil pipeline warm.

On July 30, 2021 the division approved suspension of operations at Meltwater, DS-2P.

Kuparuk: 25 more years

ConocoPhillips Alaska prefaced its newly filed Kuparuk unit plan of development with a warning that the plan was "envisioned prior to Covid-19 and the market downturn."

"The nature and extent of impacts to previously planned activities is very uncertain and will depend in part on the duration and severity of public health and market conditions," the company said in the POD submitted to Alaska's Division of Oil and Gas May 1, 2020. It covered Aug. 1, 2020 through July 31, 2021.

But while there might not have been a lot of activity in the POD period, in discussing facilities issues the company said it was looking at upgrades to support another 25 years of Kuparuk production.

At the time there were 46 drill sites for Kuparuk and 878 active wells, 506 producers and 372 injectors, with average oil production in 2019 of 73,000 bpd, water production of 557,000 bpd and water injection 675,000 bpd.

Activities for calendar year 2019 included: 22 coiled tubing drilling wells, including five West Sak wells, for a peak incremental oil rate of approximately 2,100 bpd gross.

GKA appraisals

ConocoPhillips Alaska said the overlying Nuna Moraine was being tested for productivity and waterflood performance, with a two-well pilot drilled in late 2018 and two follow-up well pairs planned to further de-risk waterflood performance.

"Coupled with results from special core analyses, this dynamic data will guide future plans for Nuna Moraine."

The company said in its POD that it brought the 1H-Ugnu-401 well back online in April 2019. The well had been shut-in in 2016 because of electric submersible pump problems, which the company said it was continuing to troubleshoot "in an effort to determine if higher oil production rates can be sustained."

Alaska Oil and Gas Conservation Commission records show the 1H-Ugnu-401 produced 822 barrels in April 2019 but nothing since.

Isaacson taking reins

Marushack also told RDC attendees he was retiring at the end of January 2021 after 38 years with ConocoPhillips.

EREC ISAACSON

Erec S. Isaacson, who has been with ConocoPhillips for nearly 35 years, would be replacing him.

In 2006, Isaacson moved to Alaska, first holding the position of manager, Alaska exploration, and later as vice president, commercial assets, with accountability for non-operated, pipeline and Cook Inlet assets.

He began his career with Phillips Petroleum Co. in Bartlesville, Oklahoma, in 1986 as a geophysicist in upstream technology. He held various exploration and development positions in the company, including assignments in Houston, Odessa and Stavanger.

Hitting reset in 2021

In a presentation at Meet Alaska in late March 2021, Isaacson described 2021 as "hitting reset."

The company would focus on lowering costs and engaging stakeholders and would also resume regular development drilling, as well as progress on $1.1 billion in projects across the North Slope: Greater Mooses Tooth No. 2 construction, Alpine expansion, Willow permitting, Nuna development and ongoing work at the Eastern NEWS (North East West Sak) at the Kuparuk River unit.

Nine months before Covid-19 hit ConocoPhillips Alaska was planning a few years of appraisal as part of its Kuparuk River program, leading to first oil in 2022

In his Meet Alaska presentation, Isaacson put the timeline for first Nuna oil at the "mid-2020s."

GKA exploration

On the exploration side, ConocoPhillips Alaska said it continued to monitor two existing horizontal producer/injector well pairs at the Torok (Moraine) reservoir for long-term deliverability and waterflood, using the information to determine optimal inter-well spacing.

"Based on the performance of these wells, a new well pair is planned to be drilled in 2022," the company said.

Coyote, new GKA find

Alaska got encouraging news in the June 30, 2021 ConocoPhillips market update, including the planned development of a new North Slope oil discovery, Coyote, which was on the western side of Kuparuk, and to the east of Nuna.

Later that morning at RDC's annual luncheon in Anchorage Isaacson said Coyote was a Brookian topset above the Nuna Torok discovery, describing Coyote as shallow.

In other words, Coyote appeared to be another in a long line of North Slope Nanushuk discoveries.