Petroleum news

page 10 LNG plant key to stable Cook Inlet market, license renewal good for all

Vol. 12, No. 37 • www.PetroleumNews.com *A weekly oil & gas newspaper based in Anchorage, Alaska* **Week of September 16, 2007 • $1.50**

Technology makes for happy herd

JUDY PATRICK

After 30 years of study, much has been learned about the North Slope's Central Arctic herd as industry adapts to accommodate the animals. Above a lone caribou passes under pipelines at the Kuparuk Operations Center.

TransCanada unsure on AGIA app

TransCanada, a Calgary-based pipeline firm, has not decided whether it will submit an application to the State of Alaska to build a natural gas pipeline under the Alaska Gasline Inducement Act, company spokeswoman Shela Shapiro told Petroleum News Sept. 12.

In a Sept. 9 article titled "Pearce sets record straight," Petroleum News reported TransCanada had indicated it would not be submitting a proposal to build a gas line from the North Slope under AGIA. When a reader said he had not heard TransCanada had dropped out, Petroleum News asked TransCanada for clarification.

"A decision will be made by the TransCanada board," Shapiro said. "That decision hasn't been made yet. Our work right now is to prepare the information for the board review and to be ready" to submit an application under AGIA "should the board direct us"

see **TRANSCANADA** *page 22*

Anadarko files to drill gas wells

A state official told Petroleum News Sept. 12 that Anadarko Petroleum has submitted a plan of operations to drill two wells in the undeveloped Gubik gas field in the Brooks Range Foothills. That confirms Petroleum News' earlier prediction that Anadarko plans to drill the first commercial gas well in northern Alaska this coming winter.

Anadarko and its Foothills partners BG and Petro-Canada hold approximately 2.2 million acres between the Canning and Colville rivers along the southern boundary of the North Slope. The Gubik field is near Umiat just outside the eastern margin of the National Petroleum Reserve-Alaska. The leases sit primarily on land owned by Arctic Slope Regional Corp. A few leases are on state land, most of them purchased in recent lease sales by Anadarko and included in the Foothills partnership.

Anadarko and its partners have ordered a new lightweight

see **ANADARKO** *page 22*

LAND & LEASING

Back in the game

Bill Armstrong team returns to Alaska, this time in the Cook Inlet basin

By KAY CASHMAN

Petroleum News

BILL ARMSTRONG

STU GUSTAFSON

ED KERR

JUDY PATRICK PHOTOS

The independent responsible for bringing three new oil companies to Alaska's North Slope in 2002-05 is back in the state — this time in Southcentral Alaska's Cook Inlet basin. A newly formed, local affiliate of Denver-based Armstrong Oil and Gas, Armstrong Cook Inlet LLC, has taken over as operator of the North Fork gas unit from Gas-Pro LLC. Leases in, and near, the southern Kenai Peninsula unit have also been transferred to Armstrong CI, a State of Alaska official told Petroleum News Sept. 10.

What's more, the top executive of all the Armstrong companies, Bill Armstrong, said the North Fork deal is just the first of possibly several more to come.

see **ARMSTRONG** *page 18*

EXPLORATION & PRODUCTION

Shell wells still possible

Starts to idle contract personnel, but says door not shut on '07 Beaufort drilling

By ALAN BAILEY

Petroleum News

It's been more than a month since Shell hoped to start its drilling program in the U.S. Beaufort Sea off Alaska, and three weeks since the U.S. Court of Appeals for the 9th Circuit placed a temporary injunction on that program. But Shell says that it could still drill, were the court to reverse its decision in the near future.

"If the court reverses the injunction quickly, Shell could proceed with its drilling program either by reactivating the Frontier Discoverer or conducting work with the Kulluk, our drilling rig built specifically for Arctic conditions and anchored in the Canadian Beaufort," Shell spokesman Curtis Smith said Sept. 11.

Shell had been planning to use the floating drilling platform Kulluk and the drillship Frontier Discoverer to drill three wells in its Sivulliq prospect (formerly the Hammerhead prospect) on the western side of Camden Bay during the 2007 open water season.

And in a guest editorial in this edition of Petroleum News, Marvin Odum, vice president of Shell Exploration & Production Americas, confirmed Smith's statement, saying, "It is possible that if the Court lifted its injunction that Shell could continue with its 2007 operations."

see **SHELL** *page 22*

NATURAL GAS

Minister: Arctic gas vital

Study for NWT outlines economic, environmental benefits of Alaska, Mac gas

By GARY PARK

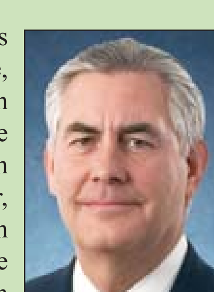
For Petroleum News

Failure to develop Arctic gas from Alaska and Canada along with currently proposed LNG projects in Russia and Norway could cost North American consumers C$338 billion (US$321 billion) between 2014 and 2025, while raising carbon dioxide emissions by 280 million metric tons if coal was used instead to feed power plants, says a study commissioned by the Northwest Territories government.

Released by NWT Industry Minister Brendan Bell during a cross-North America mission to sell the importance of Arctic gas resources, the study by Calgary-based Angevine Economic Consulting assumes a base case of initial throughput from Alaska of 4 billion cubic feet per day by 2017,

see **ARCTIC GAS** *page 21*

MGP partners wrestle with Mac gas line costs



ExxonMobil Chairman and CEO Rex Tillerson

The Mackenzie Gas Project is on the table, not the shelf, even though its current price tag of C$16.2 billion could be headed higher, ExxonMobil Chairman and Chief Executive Officer Rex Tillerson told panel on global energy security in Calgary Sept. 7.

The regulatory process, already dragging

see **COSTS** *page 21*

contents

Petroleum News *A weekly oil & gas newspaper based in Anchorage, Alaska*

Alaska - Mackenzie Rig Report

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status

Alaska Rig Status

North Slope - Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Akita Drilling Ltd.			
Dreco 1250 UE	63 (SCR/TD)	Racked in Deadhorse	Anadarko
Doyon Drilling			
Dreco 1250 UE	14 (SCR/TD)	Rig summer maintenance	BP
Sky Top Brewster NE-12	15 (SCR/TD)	Kuparuk IJ-176	ConocoPhillips
Dreco 1000 UE	16 (SCR/TD)	Workover Prudhoe DS 5-40	BP
Dreco D2000 UEBD	19 (SCR/TD)	Alpine CD4 - Rig Maintenance	ConocoPhillips
OIME 2000	141 (SCR/TD)	West Sak 1J-107	ConocoPhillips
TSM 7000	Arctic Fox #1	Stacked in Yard	Pioneer Natural Resources
	Arctic Wolf #2	Stacked in yard	FEX
Kuukpik	5	Stacked in Deadhorse Available till 1/15/08	Available
Nabors Alaska Drilling			
Trans-ocean rig	CDR-1 (CT)	Stacked, Prudhoe Bay	Available
Dreco 1000 UE	2-ES	Prudhoe Bay DS 14-02C	BP
Mid-Continental U36A	3-S	Kuparuk KRU 3Q-11	ConocoPhillips
Oilwell 700 E	4-ES (SCR)	Milne Point MPF-66	BP
Dreco 1000 UE	7-ES (SCR/TD)	Prudhoe Bay N-27i	BP
Dreco 1000 UE	9-ES (SCR/TD)	Aurora S-400	BP
Oilwell 2000 Hercules	14-E (SCR)	Stacked	Available
Oilwell 2000 Hercules	16-E (SCR/TD)	Stacked	Available
Oilwell 2000	17-E (SCR/TD)	Stacked, Point McIntyre	Available
Emsco Electro-hoist -2	18-E (SCR)	Stacked, Deadhorse	Available
OIME 1000	19-AC (SCR)	On-site at Oooguruk	Pioneer Natural Resources
Emsco Electro-hoist Varco TDS3	22-E (SCR/TD)	Stacked, Milne Point	Available
Emsco Electro-hoist	28-E (SCR)	Stacked, Deadhorse	Available
OIME 2000	245-E	Oliktok Point OPi2	Anadarko
Emsco Electro-hoist Canrig 1050E	27-E (SCR-TD)	Stacked	
Nordic Calista Services			
Superior 700 UE	1 (SCR/CTD)	Prudhoe Bay well G-9	BP
Superior 700 UE	2 (SCR/CTD)	Prudhoe Bay well X-30	BP
Ideco 900	3 (SCR/TD)	Kuparuk well 2N-327	ConocoPhillips

North Slope - Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Nabors Alaska Drilling			
Oilwell 2000	33-E	Stacked	

Cook Inlet Basin – Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Aurora Well Service			
Franks 300 Srs. Explorer III	AWS 1	Stacked at Nikiski	Available
Marathon Oil Co. (Inlet Drilling Alaska labor contractor)			
Taylor	Glacier 1	Grassim Oskolkoff No. 6	Marathon
Nabors Alaska Drilling			
National 110 UE	160 (SCR)	Stacked, Kenai	Available
Continental Emsco E3000	273	Stacked, Kenai	Available
Franks	26	Stacked	Available
IDECO 2100 E	429E (SCR)	Stacked, removed from Osprey platform	Available
Rigmaster 850	129	NNA-1	Chevron
	106	In transit from Canada	Chevron
Rowan Companies			
AC Electric	68 (SCR/TD)	Drilling Hansen 1A-L1 well at Cosmopolitan	Pioneer Natural Resources

Cook Inlet Basin – Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Unocal (Nabors Alaska Drilling labor contractor)			
Not Available			
XTO Energy			
National 1320	A	Platform A no drilling or workovers at present	XTO
National 110	C (TD)	Idle	XTO

Mackenzie Rig Status

Canadian Beaufort Sea

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Seatankers (AKITA Equtak labor contract)			
SSDC CANMAR Island Rig #2	SDC	Set down at Roland Bay	Devon ARL Corp.

Mackenzie Delta-Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
AKITA Equtak			
Dreco 1250 UE	62 (SCR/TD)	Rig Racked in Inuvik, NT	Available
Modified National 370	64 (TD)	Racked in Inuvik, NT	Available

The Alaska - Mackenzie Rig Report as of September 13, 2007. Active drilling companies only listed.

TD = rigs equipped with top drive units WO = workover operations
CT = coiled tubing operation SCR = electric rig

This rig report was prepared by Alan Bailey


JUDY PATRICK

Baker Hughes North America rotary rig counts*

	September 7	August 31	Year Ago
US	1,814	1,829	1,728
Canada	335	305	491
Gulf	72	73	91

Highest/Lowest		
US/Highest	4530	December 1981
US/Lowest	488	April 1999
Canada/Highest	558	January 2000
Canada/Lowest	29	April 1992

*Issued by Baker Hughes since 1944

SERVICE & SUPPLY


COURTESY NORTHWEST STRATEGIES

End of an era: The VECO sign comes down from its Anchorage headquarters, to be replaced by the new owner's moniker, CH2M Hill.

CH2M Hill finalizes acquisition of VECO

PETROLEUM NEWS

Denver-based CH2M Hill said Sept. 7 that it has finalized the acquisition of VECO, initiating a sign-changing effort at VECO's headquarters building in Anchorage the same day. The two companies signed a letter of intent for exclusive negotiations on May 15.

"Our extensive due diligence has confirmed this is an outstanding company with an exceptional workforce and project resume," said Lee McIntire, president and chief operating officer of CH2M Hill, a global full-service engineering, construction and operations firm. "Like CH2M Hill, our new colleagues' business operations are built on a commitment to safety, quality and client satisfaction. The employees of VECO are a great fit for our firm. We are proud to call them our colleagues."

The former VECO organization includes businesses specializing in program management, construction, engineering, procurement, operations and maintenance that have been serving oil and gas, mining and power clients since 1968, CH2M Hill said in a press release. In addition to its base of operations in Alaska, VECO has major operations in other parts of the United States, western Canada, Russia and the Middle East.

The VECO name will go away, replaced by CH2M Hill.

"The Allen family is pleased that VECO's legacy of hard work, client service and professional excellence will continue with this acquisition. The transaction results in over 4,000 VECO employees becoming CH2M Hill shareholders, and we see a very bright future for our loyal employees and VECO clients," said Tammy Kerrigan, who served as chair of VECO's board.

"The acquisition of VECO represents the single largest investment that CH2M Hill has made and speaks to our commitment to Alaska," said Garry Higdem, who will lead the new business for CH2M Hill. "This deal augments CH2M Hill's existing oil and gas experience and provides us a world-class platform to bolster our project delivery capabilities around in the world."

Employee-owned CH2M Hill generates more than $5 billion in revenues each year and has more than 23,000 employees in regional offices around the world. ●

EXPLORATION & PRODUCTION

Newfoundland field eyes growth

Newfoundland's offshore White Rose oil field is on the brink of a major expansion following government approval of plans to recover an additional 24 million barrels, a step closer to developing two more discoveries holding a combined 190 million barrels. The White Rose project is owned by operator Husky Energy 72.5 percent and Petro-Canada 27.5 percent.

A final decision to introduce the so-called South White Rose Extension pool still needs ratification from Petro-Canada. That hinges on the outcome of negotiations with the Newfoundland government on fiscal terms and local economic benefits.

White Rose is currently targeted to produce 120,000-125,000 barrels per day on an annualized basis and has regulatory approval to achieve a maximum 140,000 bpd.

The newest addition would cost an estimated C$595 million, including C$308 million to drill and complete five wells.

But that investment would also open the way for development of the North Amethyst and West White Rose pools that have yet to reach the regulatory application stage.

—GARY PARK

● GUEST EDITORIAL

Shell committed to working with Alaskans

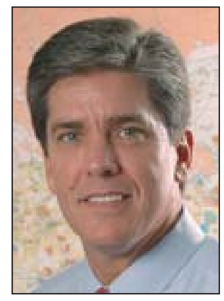
By MARVIN ODUM

More than two years ago, Shell returned to Alaska to explore for the vast oil and gas resources yet to be discovered in the state's offshore regions.

We recognized a key ingredient to our success would be finding common ground with the people of Alaska so that these resources could be developed for the benefit of all involved.

Though we may never fully understand the subsistence culture, through continued dialogue there is a great deal we can accomplish together. We will continue to listen and learn from the people and communities of the North Slope and residents across Alaska. Important work and discussions are ongoing with Mayor Itta and we are heartened by the progress being made.

We recognize that the North Slope Borough and its residents are at a critical juncture that will determine the quality of life for the next generation. We also recognize the challenge of balancing cultural preservation against the need to exist in a cash economy including the development of natural resources. This is a complicated issue for local communities and Shell stands ready to address these concerns.



MARVIN ODUM

Our experience in the Arctic makes Shell uniquely qualified to safely explore for oil and gas resources offshore Alaska. Shell also believes success in the Beaufort carries with it a potentially enormous upside for North Slope communities and the state — including hundreds of high paying jobs and new oil for the trans-Alaska oil pipeline.

Recently, the 9th Circuit Court of Appeals heard oral arguments that called into question the federal government's approval of Shell's 2007 plan of operation. The court temporarily halted our drilling activities pending a formal decision on the merits of the case. This disappointing development seriously jeopardizes our 2007 drilling season in the Beaufort Sea and regrettably impacts the residents of Alaska directly through job losses.

As part of our 2007 exploration program we recruited and trained more than 700 personnel — among them roughly 350 Alaskans, 150 of whom are Alaska Natives. Unfortunately, if we are not allowed to pursue our drilling plans, we cannot keep these dedicated workers on board. For this reason, Shell is now in the process of initiating a staged release of staff and contract personnel associated with our planned 2007 drilling program.

These people and jobs are important to Alaska and to Shell. They are proof of our commitment to a shared future. It is possible if the Court lifted its injunction that Shell could continue with its 2007 operations.

It is my vision that Shell and the people of Alaska can share common goals. We stand by the people and communities of Alaska. We will continue to listen, learn and work with Mayor Itta and the North Slope communities, including the North Slope Borough and Alaska Eskimo Whaling Commission, to find solutions that allow us to protect the region's subsistence culture recognizing the role of traditional knowledge while responsibly developing Alaska's abundant offshore energy resources.

We will only have a successful program in Alaska if it benefits not only the current residents of the entire state, but the next generation as well. ●

Marvin Odum is executive vice president of Shell Exploration & Production-Americas

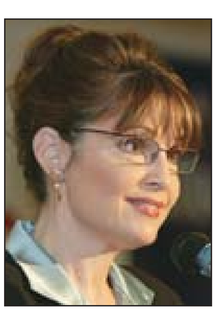
● GUEST EDITORIAL

State of Alaska determining value of its oil

By GOV. SARAH PALIN

Excited and grateful to tackle the issue, my administration and the 25th State Legislature owe it to Alaskans to determine the value of Alaskan-owned resources, declare that value and move the state forward as we share that value with producers of our resources.

Alaska's extremely valuable oil supply is being sold for us today at a premium. Markets are hungry for our oil, and we have a mutually beneficial relationship with these companies as they pump oil for us, deliver it across America and sell it for healthy company profits.



JUDY PATRICK

"I tasked our Department of Revenue to take the politics out of this issue, crunch the numbers, show Alaskans a formula that could produce what the 24th Legislature was promised, close PPT's loopholes, and create an attractive investment environment for new exploration and development of our resources." –Alaska Gov. Sarah Palin

Alaska's share of oil wealth comes from combining royalties and taxes. Previously, the 24th Legislature placed a value on oil and adopted the Petroleum Profits Tax system to generate about a $2.2 billion portion of the state share this year to fund essential services. But PPT is not working as promised and Alaskans will be hundreds of millions of dollars short of what PPT was supposed to provide. Also, PPT has many loopholes that allow oil companies to write off expenses such as deferred maintenance costs to fix their corroded pipes, and we increased our audit and litigation risks without tools to protect Alaskans. Many other PPT shortfalls, coupled with oil service company corruption scandals, lead me to propose solutions to more clearly and equitably determine our oil's value through a more sensible system.

I tasked our Department of Revenue to take the politics out of this issue, crunch the numbers, show Alaskans a formula that could produce what the 24th Legislature was promised, close PPT's loopholes, and create an attractive investment environment for new exploration and development of our resources.

The solution we've developed is Alaska's Clear and Equitable Share plan. ACES is the hybrid valuation plan incorporating gross and net features that assures us appropriate value during high oil prices, shares risks during downturns, and credits companies for new private sector investments.

We expected criticism over aspects of ACES, especially from oil industry players, but it was unexpected and disappointing to hear a legislator's warning upon presenting the plan, that, "The fight is not over!" What fight? My administration is seeking fulfillment of Article VIII of our state constitution that mandates we develop resources for the maximum benefit of Alaskans. Legislators swore to uphold that same constitution, putting us all on the same team with the same goal. Though it may be unconventional in the world of Alaskan politics, I am committed to working together as a team to adopt the best plan, with legislators' welcomed amendments to make ACES even better. How 'bout we go into this without assuming that "fighting" and politics-as-usual is the only way to debate, determine, and share our oil's value with producing companies?

Another critique lobbed is that determining our oil's value is too tough to tackle in a 30-day special session, suggesting we shouldn't even begin to fix what is obviously broken. But legislators have an extremely full agenda (including the politics involved in an election year) to address in their new, voter-mandated 90-day session: All the more reason to consider ACES concepts sooner, rather than later. The concepts aren't new to legislators who were engaged in previous PPT debates. Key to success though is to go into this with an enthusiastic, positive approach instead of a defeatist attitude and procrastination.

It's imperative we determine our oil's value, today, especially considering changes on the national scene that impact Alaska's receipt of federal funds, our challenge in reining in government growth, and our commitment to a competitive investment environment that attracts new development.

Henry Kissinger said: "Too often competing pressures tempt one to believe an issue deferred is a problem avoided; more often it's a crisis invited." We can't defer because the crisis we'd invite is the stifling of an energized, pro-private sector climate that Alaska deserves. We won't defer because our incredible potential, including good jobs for Alaskans in a healthy and educated state, is out of reach until we trust our oil wealth is shared clearly and equitably. ●

Sarah Palin is the governor of the state of Alaska.

Petroleum news

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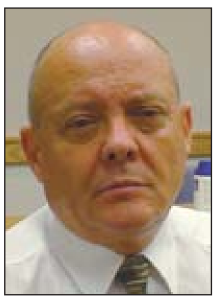
EXPLORATION & PRODUCTION

State of Alaska investigates BP fires

Four incidents within a month are too many, Department of Natural Resources says; wants to find out if there is systemic problem

By ALAN BAILEY
Petroleum News

Following a fourth BP North Slope fire incident in five weeks, the Alaska Department of Natural Resources has sent a team to the North Slope to look at the oilfield infrastructure involved and to investigate BP's process safety management. The department is concerned that a pattern of fire incidents is emerging and that this pattern could lead to a major incident involving injury to personnel, DNR Commissioner Tom Irwin said in a press conference called in Gov. Sarah Palin's office on Sept. 11.



TOM IRWIN

"We have asked for and will be meeting with top executives from BP. … The issue is being elevated. … We can't ignore four (incidents)," Irwin said. "We want to assure the public that we are watching out for these things."

Lisburne incident

In the latest incident on Sept. 10 BP had reported to the state fire marshal the ignition of some hydrocarbons at the Lisburne Production Center. But details of the incident are still emerging, said Jonne Slemons, DNR petroleum systems integrity coordinator. It appears that ignition occurred after vapors had vented into a tank during a pigging operation, she said. No one was injured in the incident.

Irwin said that the previous incidents occurred at Prudhoe Bay Gathering Center 1 on Aug. 10, at Badami on Aug. 10 and in Prudhoe Bay Flow Station 3 on Aug. 26.

"BP must immediately address the causes of these events, wherever they lie, be it equipment problems, at the facility level or at the management level," Slemons said. Two staff members from the Petroleum Systems Integrity Office are on their way to the North Slope to perform a detailed investigation, she said.

BP spokesman Daren Beaudo told Petroleum News … that the Sept. 10 Lisburne incident involved the burning of some liquid hydrocarbons at a gas flare unit. The flare unit, located hundreds of yards from the processing center, burns continuously and provides a pressure relief capability for vapors from the Lisburne facility.

DNR's Petroleum Systems Integrity Office is seeking answers to questions regarding BP's management processes, to identify any issues with daily operations and with the company's attention to process safety management, Slemons said.

"These are not new questions," Slemons said. "Others have asked them before me. We can no longer wait for the answers. The governor and Alaskans need to know that their safety and their resources are properly managed and operated. … Four fires in one month — that's above and beyond anything that is acceptable, so we're on top of it."

Minor incidents

But BP says that the incidents are not connected with each other and represent minor glitches in routine operations.

Company spokesman Daren Beaudo told Petroleum News Sept. 11 that the Sept. 10 Lisburne incident involved the burning of some liquid hydrocarbons at a gas flare unit. The flare unit, located hundreds of yards from the processing center, burns continuously and provides a pressure relief capability for vapors from the Lisburne facility, Beaudo said.

DAREN BEAUDO

"We were running a maintenance pig through the new (24-inch, three-phase) Lisburne line … from the Lisburne producing fields into the Lisburne Processing Center," Beaudo said. "We had basically a surge of hydrocarbons … and as part of the design of the facility the (excess) hydrocarbons go into a knockout drum."

A three-phase line carries crude oil, natural gas and water.

Normally the knock-out drum collects liquids when gas vents through the flaring unit, Beaudo said. In this instance, some of the liquid hydrocarbons carried over from the drum and ejected through the flare — the liquids ignited as they came out past the flare pilot light. The burning liquids settled in the flare pit, a large area that encircles the flare and is designed to catch and contain any liquid not completely burned in the flare, he said.

"It was simply the flare system working," Beaudo said.

According to BP the Aug. 6 and Aug. 26 incidents involved some leaking lubricating oil catching fire on hot parts of turbines. The Aug. 10 incident involved the ignition of some diesel fuel that had leaked into the crankcase of a diesel generator, the company said. In each case the fire was quickly extinguished.

BP: safety systems worked

Beaudo said that in each of the events BP's safety systems had worked.

"Of the four incidents, we've investigated the first three and we've begun investigation of yesterday's flare event and we'll share what we've learned with regulators," Beaudo said. "These (incidents) are isolated and they're not any part of a pattern."

The production impact of the incidents has been minimal and BP's notifications of the incidents to the state and others have gone beyond the legal requirements, Beaudo said.

see FIRES page 7

● FINANCE & ECONOMY

Trust shakeout: Some stay, others quit

Little consensus on Canada energy trust situation; tax issue expected to figure in next election; concern over foreign takeovers

By GARY PARK
For Petroleum News

The evolution of Canada's income trust world continues to unfold, with some deciding to keep building and others bailing out.

Crescent Point Energy Trust forked over C$400 million to reinforce its dominant presence in the light oil Bakken play of southern Saskatchewan, while oilfield services powerhouse CCS Income Trust virtually completed its plan to go private.

Crescent Point landed a deal to buy Innova Exploration for C$400 million in cash and debt, almost a year after launching its successful bid to acquire Mission Oil & Gas in a C$760 million transaction.

The trust's President and Chief Executive Officer Scott Saxberg said results from the Mission acquisition have "exceeded our expectations" and buying Innova "is a logical step in the sustainable development and control of the 1.5 billion barrel resource play."

Under the deal, Crescent Point will gain 4,300 barrels of oil equivalent per day (72 percent of its crude), of which 2,800 boe per day comes from the Bakken area.

Innova also delivers 15 million boe of proved plus probable reserves and almost 200,000 net acres of undeveloped land.

As a result, Crescent Point's production will increase by about 10 percent to 30,000 boe per day and its drilling budget will rise by 10 percent to C$165 million.

UBS Securities analyst Grant Hofer said the deal will allow Crescent Point to provide its unit holders with strong production and cash flow sustainability and significant reserves and value growth over the next few years.

He said that given the "compelling economics and attractive profile" of the Innova asset the trust should be well placed to "deliver solid, low-risk returns for investors for the foreseeable future."

Meanwhile the tug-of-war over the future of trusts showed some new life earlier in September when 35 executives from the sector met with two leading members of the Liberal Opposition, Ralph Goodale and John McCallum, who said that if they win the next federal election they will scrap the trust legislation.

CCS goes private

In contrast, CCS saw no future in the trust world and neither did the bulk of its unit holders, who voted 92.8 percent in favor of taking the trust private.

Their overwhelming endorsement of the plan includes a price of C$46 per unit — up 21.4 percent from the closing price when the offer was made — as part of the C$3.5 billion buyout by a group of private investors.

David Werklund, the founder of CCS who will remain president and chief executive officer when the transaction closes in the fourth quarter, said the Canadian government's intention to start imposing a 31.5 percent corporate tax on trusts in 2011 was one of the factors pushing CCS out of the trust fold.

He said the new tax structure would not be in the interest of CCS stakeholders, who saw more value in the transaction that they were receiving from the public markets.

With 3,000 employees and four divisions processing drilling waste, marketing recovered oil, cleaning up old industrial sites and providing well services, CCS has operations in Canada, the United States and Peru.

The new owners will be CAI Capital Partners, Goldman Sachs Capital Partners, Kelso & Co., Vestar Capital Partners, British Columbia Investment Management, Alberta Investment Management and O.S.S. Capital Management.

Trusts an election issue

Meanwhile the tug-of-war over the future of trusts showed some new life earlier in September when 35 executives from the sector met with two leading members of the Liberal Opposition, Ralph Goodale and John McCallum, who said that if they win the next federal election they will scrap the trust legislation.

McCallum said the anger over the proposed trust change runs so deep it will be a major issue in the election campaign, which is expected either this fall or in 2008.

McCallum and Goodale said the Liberals are also pondering allowing a broad-based use of the tax structure by all sectors, with restrictions to prevent initiatives solely designed to dodge taxes.

The Liberals have said they would introduce a 10 percent tax on all income trust distributions, which would be refundable to Canadian residents, rather than the 31.5 percent corporate tax under the Conservative government policy.

John Dielwart, chief executive officer of ARC Energy Trust and leader of the Coalition of Canadian Energy Trusts, said the trust law has already resulted in foreign takeovers of Canadian trusts, costing Canadian jobs.

"We've seen a very good business end up in the hands of foreigners and we've seen very good businesses end up with jobs at risk in Canada now," he said.

Coutu: trusts on defensive

Marcel Coutu, chief executive officer of the Canadian Oil Sands Trust, which owns almost 36 percent of the Syncrude Canada consortium, said the trust sector is now operating on the defensive instead of being in a strong growth position.

Investment banker Crosbie & Co. said the total number of income trust sales and acquisitions across the total spectrum surged 94 percent in the second quarter to 62 from 32 a year earlier, driving the value of deals up to C$12.2 billion from C$2.9 billion the first quarter and C$2.3 billion in each of the previous four quarters.

Colin Walker, Crosbie's managing director, said he suspects the rise in trust deals mirrors the fallout from the government's announcement last fall that it would break an election promise not to tax trusts.

"This is about the period when you would expect that people decided it was wise to put themselves on the block and make something happen," he said, noting that trusts have now had time to assess their future and do the sales preparation.

Sayer Energy Advisors estimates that energy trust and assets worth C$4.5 billion changed hands in the first half of 2007, accounting for 18 of 104 oil and gas deals and 19 percent of the M&A enterprise value. ●

continued from page 6

FIRES

"Fires are regrettable, but we operate a large oil field and they do happen," Beaudo said. "… Safety systems worked in each of these events." That's why BP has multi-layered safety systems and personnel trained to respond, he said.

But, regardless of the seriousness of the individual incidents, given the number of incidents that have occurred within a relatively short time period, the state wants to be pro-active in identifying any systemic problems in BP's North Slope operations, Irwin said.

"We'd much rather be telling Alaskans we're working on this, we're aware of it, than standing here explaining to Alaskans why we didn't, if something serious happens. This is a preventative approach," Irwin said. "We're serious about this (petroleum systems integrity) program." ●

● FINANCE & ECONOMY

Alaska gas line viable despite soft market

Consumption of natural gas declines in United States, increases worldwide, says economist Mark Finley in presentation of BP report

By WESLEY LOY

Anchorage Daily News

U.S. natural gas consumption has declined for two consecutive years, but that doesn't necessarily mean chances for an Alaska gas pipeline are diminished, a BP economist said Sept.6.

While nothing is guaranteed, the long-term outlook is that the country — the world's biggest natural gas user — will need to tap all available sources, including Lower 48 production, imports as well as Arctic gas, said economist Mark Finley.

Finley, of Washington, D.C., has been traveling the world briefing reporters, industry groups and others on the annual "BP Statistical Review of World Energy."

The review is a respected, data-packed guide to supply and demand for major energy sources including oil and gas, coal, and nuclear and hydroelectric power. BP, which runs the largest U.S. oil field at Prudhoe Bay, has produced the review for 56 years.

Among the report's findings for 2006:

• World oil consumption grew by less than 1 percent, the weakest growth since 2001. The lower demand was largely in response to high crude oil prices peaking well above $70 a barrel.

• World natural gas consumption grew by 2.5 percent, close to the 10-year average, but U.S. gas consumption declined for the second year in a row.

• U.S. gas production rose by 2.3 percent, the strongest gain since 2001. The growth was due to recovery from hurricane-related outages in the Lower 48, as well as more rigs drilling for gas, Finley said.

Alaska politicians again are trying to entice oil companies or other firms to build a pipeline to carry the North Slope's vast gas reserves. The gas in the Prudhoe Bay oil field has been stuck in the ground since its discovery more than 30 years ago; and there's nearly nine times that much that has either been discovered and not developed because of no market or is expected to be discovered, says the U.S. Geological Survey.

The most likely option, many energy companies say, is a pipeline costing $20 billion or more that would run southeast off the Slope into Canada to as far as Chicago.

But the staggering scale, cost and risk of such a project have long precluded it from happening, despite the best efforts of a succession of governors and occasional spikes in gas prices. Gov. Sarah Palin has invited potential builders to submit proposals by Nov. 30 to build a line and lock up a package of financial incentives from the state. A few firms, including pipeline giant MidAmerican Energy, have said they will submit proposals by that date.

U.S. market weakness could be temporary

A key factor in the success of such a line, of course, is market demand for gas.

Alaska gas has competition from alternative energy sources that industrial users and power utilities can switch to, Finley said.

One major competitor is coal, of which North America has a great deal. Coal is a highly polluting fuel and carries antipollution costs in some countries, but technological advances could clean it up. And recently, coal demand has surged due to bargain prices.

"The lesson of the past few years is, cheap beats dirty," Finley said.

Another worry for Alaska gas pipeline backers has been the threat of rising imports in the form of liquefied natural gas, or LNG. Energy companies are building, or have proposed, numerous North American ports for receiving LNG shipments.

But while LNG shipments globally rose by a strong 11.8 percent in 2006, U.S. imports declined slightly, Finley said.

The apparent weakness in the U.S. gas market could be temporary. For one thing, weather is a big factor for gas demand, and last year's warm weather helped demand, Finley said. ●

—Petroleum News contributed to this report

● GOVERNMENT

Alberta premier baffles industry

Stelmach halts seismic testing at northern Alberta lake granted to privately owned OSUM Oil Sands, over-ruling his own regulators

By GARY PARK

For Petroleum News

Alberta Premier Ed Stelmach has left the industry groping around in a policy fog after halting seismic testing at a northern Alberta lake, over-ruling his own government's regulators in the process.

Faced with strong public opposition, including demands that the province either buy back or exchange the lease, he suspended a seismic license granted to privately owned OSUM Oil Sands to run tests at Marie Lake, 180 miles northeast of Edmonton, in hopes of establishing a 30,000 barrel per day operation.

In the wake of Stelmach's decision to suspend the seismic work, the government had difficulty explaining what direction it was taking.

The premier said that because the bitumen recovery technology proposed by OSUM was unproven. "I have decided that seismic testing at Marie Lake will not proceed," he said.

The Ministry of Sustainable Resource Development approved the testing procedures in August, including the use of underwater air guns to evaluate a bitumen deposit under the lake, while attaching a long list of conditions.

OSUM promised to post an C$80,000 environmental security deposit and agreed to make a 30 percent reduction in the planned use of the air guns for an echo-sounding seismic survey.

GLJ Petroleum Consulting has estimated the net recoverable resources at 1.1 billion barrels as a result of winter drilling and preliminary seismic activities, but no reserves can be booked until a commercial project is approved.

Area residents complained

Stelmach, after hearing from area residents about the possible impact of the 3-D seismic program said it was time to intervene.

"This shows I'm keeping my word and trying to find a balance between continued economic growth, developing our resources and the environment," said Stelmach, who was elected premier nine months ago.

The Canadian Association of Petroleum Producers was troubled by the turn of events. It is not certain whether Stelmach is more concerned about the marine seismic testing or the steam-assisted gravity drainage technology OSUM planned to use in removing bitumen from under Marie Lake.

David Pryce, vice president of Western Canadian operations, told reporters that if the decision is a precedent it could affect the continuity of Alberta's regulatory process, leaving oil and gas companies uncertain whether there is a new "risk factor" when they bid for mineral leases.

A spokesman for Energy Minister Mel Knight told reporters OSUM's seismic testing will be suspended only until the government establishes a new policy for mining bitumen beneath water bodies.

But he was unable to say when that policy would be released, saying "this is very early in the process."

Open for business?

OSUM CEO Richard Todd told reporters he now wonders whether Stelmach is open for business by responsible companies, or not, given that a regulatory permit had been overturned.

He noted that the oil and gas industry has conducted seismic testing on more than 30 lakes in Alberta "without negative impact."

In corporate presentations, OSUM said its version of SAGD is proven, referring to pilot projects carried out by the former Alberta Oil Sands Technology and Research Authority.

OSUM President Peter Putnam said in a statement that the SAGD recovery mechanism is similar to methods used "throughout the oil sands" except that the wells for Marie Lake would extend from a tunnel far below ground rather than from pads on the surface.

He told an investment symposium in June that technology would cut well costs by 60 percent and make production of the Marie Lake bitumen profitable with oil prices at US$40 per barrel.

Putnam said the proposed method involves access to upper tier reservoirs that are currently viewed as inaccessible, impractical or uneconomic; reduces lifting costs; improves thermal process efficiency; and minimizes environmental impacts.

OSUM's property is alongside three major oil sands ventures — Imperial Oil's 160,000 bpd operation at Cold Lake, Husky Energy's 30,000 bpd Tucker project and the initial 13,500 bpd phase of Shell Canada's Orion oil sands project. ●

● EXPLORATION & PRODUCTION

Pioneer begins drilling at Cosmopolitan

By KAY CASHMAN

Petroleum News

Pioneer Natural Resources Alaska has begun drilling its offshore Cosmopolitan appraisal well from private land on a bluff overlooking Cook Inlet, about a quarter mile from Stariski Creek off the southwest coast of the Kenai Peninsula. Company spokesman Tadd Owens told Petroleum News that the oil well, sidetrack Hansen 1A L1, was spud Sunday, Sept. 9, with Rowan Rig 68.

Owens said Pioneer expects drilling to last 60 to 70 days with an equivalent amount of time for testing.

"The gross recoverable resource potential is 30 to 50 million barrels of oil," he said. If the well is successful Pioneer is looking at 12 more horizontal directional wells for development.

Former Cosmopolitan unit operator ConocoPhillips Alaska drilled a long-reach well and sidetrack, the Hansen No. 1 and Hansen No. 1A, from the onshore site in 2003, but since that time Pioneer has bought out all the working interest owners, including ConocoPhillips, Devon Energy and Forest Oil, taking over as operator of the unit, Owens said. ConocoPhillips retained a small royalty share, he said.

The 25,000-acre state/federal unit is approximately two miles offshore. The onshore pad is six miles north of Anchor Point and one-half mile west of the Sterling Highway.

Owens said Pioneer expects drilling to last 60 to 70 days with an equivalent amount of time for testing.

Cosmopolitan's oil accumulation was discovered by Pennzoil in 1967 in the 12,112-foot vertical, Starichkof State No. 1, drilled offshore with a jack-up rig. The company recovered 30 barrels of 20 degree API gravity oil from a drill stem test at about 6,900 feet and 21 barrels from a drill stem test at about 6,800 feet. Pennzoil reported encountering the top of the Hemlock formation at 6,745 feet. A second well, also drilled in 1967, found some gas at 4,000 feet but water in the Hemlock formation at 7,355 feet some two miles from the first well.

In mid-2005 Tim Dove, Pioneer's president and chief operating officer at the time, said the 2003 Hansen well and sidetrack "tested at a stabilized rate of 600 to 800 barrels a day over different intervals that lasted for three to four months." In the third unit plan of exploration approved by Alaska's Division of Oil and Gas in 2006, Pioneer was required to drill a new well or a sidetrack well to a minimum true vertical depth of 6,000 feet, with drilling to commence by Nov. 14, 2007. The well was to penetrate the Lower Tyonek sand-prone interval found in the Starichkof State No. 1 well.

Jack-up not needed

Only onshore drilling is being considered at this time, Owens said when asked if Pioneer was talking to the three companies looking at bringing a jack-up rig into Cook Inlet — Escopeta Oil, Renaissance Alaska and Pacific Energy.

Pioneer's tentative development schedule calls for permitting in 2008, facility construction in 2008-09 and development drilling in 2009-10. If all goes well, the Texas independent is hoping for first production in 2010, he said, emphasizing development had not yet been sanctioned by Pioneer and that approval was contingent on further appraisal of the prospect.

Pioneer has bought out all the working interest owners, including ConocoPhillips, Devon Energy and Forest Oil, taking over as operator of the unit, Owens said. ConocoPhillips retained a small royalty share, he said.

Pioneer is looking at both trucking and pipeline options for Cosmopolitan oil. Initially it will be trucking oil 75 miles to the Tesoro refinery, but if economics allow, the company will likely build a pipeline to the refinery, Owens said. ●

PIPELINES & DOWNSTREAM

Beaver Hills Processing rolls out plans for Canada's first new refinery in 23 years

Beaver Hills Processing is ready to make its industry debut with Canada's first new refinery in 23 years.

It is aiming to bring a C$300 million, 36,500 barrel-per-day plant near Edmonton into production in 2010, reversing a trend that has seen about 30 refineries with total capacity of 1 million bpd closed across Canada over almost four decades.

Beaver Hills is owned 50 percent by Corrillo Energy, a private Calgary-based technology firm, and 25 percent each by oilfield transporter Gibson Energy and Red Deer-based fuel retailer Parkland Income Fund.

Corrillo's major owner is ARC Financial, a Calgary private equity firm managing C$1.9 billion in energy and technology investments.

Parkland expects to obtain about 800 million liters of gasoline a year — or half its total sales — from the Beaver Hills refinery through its chain of 575 outlets in western and northern Canada.

The plant's main feedstock will be condensate extracted from natural gas rather than crude oil.

Condensate is used to thin out bitumen to facilitate its shipment through pipelines.

There is a plan to overcome a condensate shortage in Alberta by building a pipeline from the U.S. Midwest and Beaver Hills hopes to access those supplies.

The company is also pondering a revival of a 44-year-old condensate refinery in central Alberta that stopped making fuels in 2001 due to shortages of the gas byproduct and high costs. A smaller facility has been operating since then, blending and storing chemical fluids used in oilfield drilling.

The next stage for the Beaver Hills refinery will be the completion of an C$8 million feasibility study, expected about mid-2008.

—GARY PARK

● NATURAL GAS

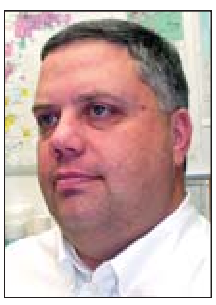
LNG plant key to stable Cook Inlet market

Supporters say renewing Nikiski facility's federal export license for two years would be good for economy, industry and state

By ROSE RAGSDALE
For Petroleum News

With what many believe is a natural gas shortage unfolding in Cook Inlet, renewing a license for a plant in Nikiski to ship liquefied natural gas to Asia seems at first glance a frivolous, if not foolhardy, proposition.

But ensuring that the 40-employee processing facility, tiny by world standards, continues to operate much as it has for the past 38 years is actually vital to the continued health of the natural gas market in Southcentral Alaska, according to Bill Popp, former oil and gas liaison for the Kenai Peninsula Borough.


Bill Popp, executive director of the Anchorage Economic Development Corp.

"It's counter-intuitive, so many people have trouble understanding how important the LNG plant is to the natural gas market in Cook Inlet," Popp told Petroleum News in an interview Sept. 10. "It would be a step backwards if we lose the LNG plant."

Popp, who now serves as executive director of the Anchorage Economic Development Corp., spent years stumping for oil and gas development in and around the Cook Inlet basin.

But moving a few miles north to Anchorage hasn't stopped Popp from weighing the consequences of a failure by the U.S. Department of Energy to renew the plant's export license.

Owners ConocoPhillips Alaska Inc. and Marathon Oil Co. applied earlier this year to DOE for a two-year renewal for 2009-2011 of their license to export LNG.

Popp said renewing the plant's export license is important for numerous reasons. Not only is the LNG plant an important contributor to the Kenai Peninsula economy and tax base, but it is also part of a delicate balancing act that enables consumers in Southcentral Alaska, including Anchorage, to enjoy a reliable supply and relatively low prices for natural gas.

Cook Inlet currently has nearly 1.7 trillion cubic feet of natural gas reserves. The basin could hold additional trillions of cubic feet of gas, according to state and industry estimates.

Plant provides supply cushion

The LNG plant offers a critical backstop for peak demand gas consumption by local utilities during the winter months "when we've come very close to brown-out," he said. Gas consumption in Cook Inlet is cyclical, decreasing during the summer and increasing in winter with sharp spikes in demand on the coldest days.

Popp said the region got a taste of what can happen when there is no cushioning "interruptible" supply of gas available last winter when Aurora Gas cancelled its contracts with commercial and industrial customers.

Popp said a "domino effect" ensued in which Tesoro Alaska's refinery was unable to obtain needed gas supplies for power generation and had to resort to using part of the oil it normally refines into products such as diesel and propane to generate its own power to run the refinery. The diverted supplies, especially propane, resulted in price hikes that hit the Alaska consumer pretty hard, he added.

Conditions likely would have deteriorated further if the 272 million-cubic-foot-per-day LNG plant had not voluntarily cut its gas consumption by 50 million cubic feet per day during the peak demand period, according to Harold Heinze, executive director of the Alaska Natural Gas Development Authority.

"Until something else comes along to take its place to accommodate the variation in gas demand in the market, we need the LNG plant," Heinze said Sept. 11. "Having it in the system is more help than problem."

Without the LNG plant, gas producers in Cook Inlet likely would have to shut in wells during part of the year because they wouldn't have a market for their gas, Popp said. This would lead to less production and potentially lost reserves because shutting in gas wells can damage the underground formations where the gas deposits are located, he said. It also would lead to cost increases and thus, higher gas prices.

Popp and Heinze are among scores of knowledgeable Alaskans who support the LNG plant's continued operation. They say the facility's presence in the market encourages independents and others to explore for more natural gas reserves in Cook Inlet, and taking the LNG plant out of the mix would result in excess gas supplies and remove the incentive for additional exploration.

Cook Inlet currently has nearly 1.7 trillion cubic feet of natural gas reserves. The basin could hold additional trillions of cubic feet of gas, according to state and industry estimates.


Bruce Richards, special assistant to the mayor, Kenai Peninsula Borough

Another supporter of the LNG plant's continued operation is Tony Izzo, former CEO of Enstar Natural Gas Co., the largest gas utility in Alaska and the major gas distributor in Southcentral Alaska.

"The Kenai LNG plant provides gas supply stability for Southcentral Alaska by backing up gas supplies for local utilities during periods of peak demand on cold days or when failures occur in the gas supply system," said Izzo, now an industry consultant, in a letter to DOE. "If the plant ceases operation in 2009, local utilities would be forced to invest or pay others to invest in costly peaking facilities. This cost ultimately would be passed on to consumers."

Describing the Cook Inlet gas market as being in transition, Izzo also cited the other reasons that Popp and Heinze offered for the plant's continued operation.


FORREST CRANE
Harold Heinze, executive director of the Alaska Natural Gas Development Authority

Looking to the future, the LNG plant and other larger gas users such as Agrium Inc.'s fertilizer plant and Tesoro's refinery, also could play an important role in bringing North Slope gas to Cook Inlet via a spur line.

Heinze, who is currently working to develop a spur line to Southcentral Alaska for North Slope gas, said the LNG plant's gas consumption is part of the economics that will make the spur line cost effective.

Popp agreed. "We need enough demand to get the North Slope gas pipeline project together, and the LNG plant is part of that demand."

Governor less enthusiastic

Despite the outpouring of support for the Nikiski plant's continued operation, the Palin administration has offered only conditional support for the license renewal. (See details is the April 15, 2007, issue of Petroleum News at www.petroleumnews.com/pnads/725459806.shtml)

This reserved approach, which mirrors sentiments expressed by some of the utilities and is intended to protect local gas consumers, has officials of the Kenai Peninsula Borough worried.

"We believe the conditions that Gov. (Sarah) Palin wants to put on the license renewal are probably fatal to the application," said Bruce Richards, special assistant to the mayor of the Kenai Peninsula Borough. "We wrote the governor in July and asked her to reconsider the state's position on the license. We've gotten no official response yet, but we've had some conversations with members of the Palin administration."

Richards said the borough's main fear is the governor's position will trump all the positive expressions of support DOE has received for the LNG plant's continued operation.

"We wonder why the state would put all that on the license. Our position is to take it off the license and negotiate the conditions with the companies," he said. "Without the license, none of it would be happening anyway."

Richards said another worry is that the plant's original permit was issued in 1969. "If the plant closes, we don't know if it would ever be permitted again."

One sign the administration may be listening is the governor's call for a trial-like hearing on the renewal application.

U.S. Sen. Lisa Murkowski added her voice to this appeal in a letter to DOE in June. She said DOE will need to resolve substantial issues of fact regarding the supply of and demand for natural gas in the Cook Inlet region in order to rule on the application.

"Scheduling a trial-type hearing, as requested by the State, will ensure that all of the relevant facts are thoroughly evaluated and an appropriate decision is reached," Murkowski added. ●

ENVIRONMENT & SAFETY

Technology aids quest for happy caribou

After 30 years of study, much has been learned about North Slope's Central Arctic herd as industry adapts to accommodate animals

By ROSE RAGSDALE

For Petroleum News

Both government and industry scientists acknowledge that the question of caribou in the oil fields of the Arctic is a very complex topic.

"It has been a challenge for us to try and study it and to make sense out of what that data has told us," said Mike Joyce, a retired biologist who worked for ARCO Alaska Inc. and its successor, Phillips Alaska Inc.

Over 30 years of constant study, of trying to figure out how oil companies on the North Slope are interacting with the caribou, and how they respond to mitigation, the oil industry and government agencies have worked to find better ways to coexist with the caribou and other wildlife species.

In the Kuparuk River oil field, for example, when the oil companies first realized in the early 1970s that there was a caribou herd called the Central Arctic herd in the vicinity, scientists established the first population estimate of the herd at about 3,000 animals.

In three decades, regular censuses show the herd has grown to exceed 31,000 animals.

At the same time, industry plopped a 40-pad oil field down in the middle of the area where the Central Arctic caribou herd lives and calves, bringing to the area about 160 miles of roads, and hundreds of vehicles running back and forth in all directions at all times of the day.

The oil industry's challenge has been to figure out how to understand what influence its presence is having on the caribou, their migration patterns and their very strong traditional use of the area. The herd, meanwhile, has continued to grow rapidly, and its traditional use patterns have had a high degree of annual variability, scientists say.

"When we start to think that maybe we are beginning to understand something that is going on, then the CAH loves to throw us a little curve and makes it a little puzzle, so that maybe the traditional use isn't quite what we understood it to be. So it's been a very difficult topic. It has created lots of debate," Joyce told participants at a technology conference, "Established Oil & Gas Practices and Technologies on Alaska's North Slope," sponsored by the U.S. Department of Energy in April 2000.

Still, much has been learned about the herd over the past 30 years, and industry has adapted its operations to accommodate the caribou's needs.

With the help of government and industry scientists, including independent consultants such as Alaska Biological Research in Fairbanks, significant gains have been made in understanding the species and its habitat.

The oil industry's goal has been to have "happy caribou" — to allow the Central Arctic herd do what it wants to do, completely undisturbed, according to Joyce.

An image of "happy caribou" bedded down in the oil fields, with steel oilfield infrastructure in the background has been immortalized during the past decade in national debate over allowing oil and gas development in other areas of the North Slope currently off limits.

Spacing roads and pipelines

One of the first issues that North Slope operators had to resolve was putting pipe and roads and traffic in the middle of the caribou herd's movement patterns.

JUDY PATRICK

A lone caribou passes under pipelines at the Kuparuk Operations Center.

They tackled the gargantuan task of accumulating data on the herd's movements to determine what the patterns are.

Imagine young grad students sitting in towers across the North Slope and tracking the actual movements of every individual caribou.

This rather low-tech undertaking resulted in a complex distribution map, a spaghetti diagram that showed movement patterns and how the caribou interacted with roads and pipelines when they encountered them.

"You'd like to see nice straight lines that run across it, but we don't have straight lines — we have a whole mass of confusion," Joyce said in 2000. "In the early days, the late '70s to the early '80s, pipelines were right on the ground, gravel roads were right next to the pipelines, and the caribou had no visual window to see if there was free range on the other side of that limit."

As a result, the caribou did a lot of wandering and their distribution patterns reflected their confusion.

But industry researchers studied the problem and found that it wasn't the gravel or the roads that caused problems.

Rather, it was the combination of low pipelines adjacent to the gravel roads, and as animals approached this obstacle, their line of sight was blocked.

The industry responded by building what amounted to sidewalks for the caribou over the pipelines — gravel ramps called "caribou ramps."

"We built and studied several different designs in the late '70s, early '80s, and what we often found was that caribou would use the ramps sometimes, but they would not travel along the linear feature to search for a ramp. And often, they would cross right next to the ramps, without actually using the ramp," Joyce recalled.

But the animals did use the ramps to some degree, so scientists concluded that the ramps could be beneficial in key areas, especially if researchers could figure out what preferred crossing locations might be.

They also learned that the caribou did not use the ramps in selective-search fashion.

Researchers also studied the pipelines. In the early days, the pipe was built right on the tundra surface. Welders hated to get down on their knees, and they hated to build scaffolding. Instead, they wanted to work at belt-high or chest-high levels, which often meant that the bottom of the pipe was too low for a caribou to walk under.

"We started looking at putting pipe up at a level of five feet high in the early 1980s, and found that the caribou had good passage success under that taller platform," Joyce said.

So a new standard was born — a minimum of five feet from the ground to the bottom of the pipe. For linear features, pipelines in particular, from the early or mid-70s to the early to mid-80s, industry began to keep the pipe up off the tundra, and also to separate the pipe from the road. Instead of putting the pipeline right next to the road, the companies spaced them some distance apart.

Joyce said this practice evolved from a crude understanding and use of ice roads in the early days as a development technique. Instead of having a gravel pad for construction of the pipelines, the industry began to build pipelines from ice roads, thereby providing the distance needed to help the caribou get through.

No traffic jams for caribou

The next focus was traffic. Pipes were okay, using the right design and orientation. The gravel road itself was not a problem.

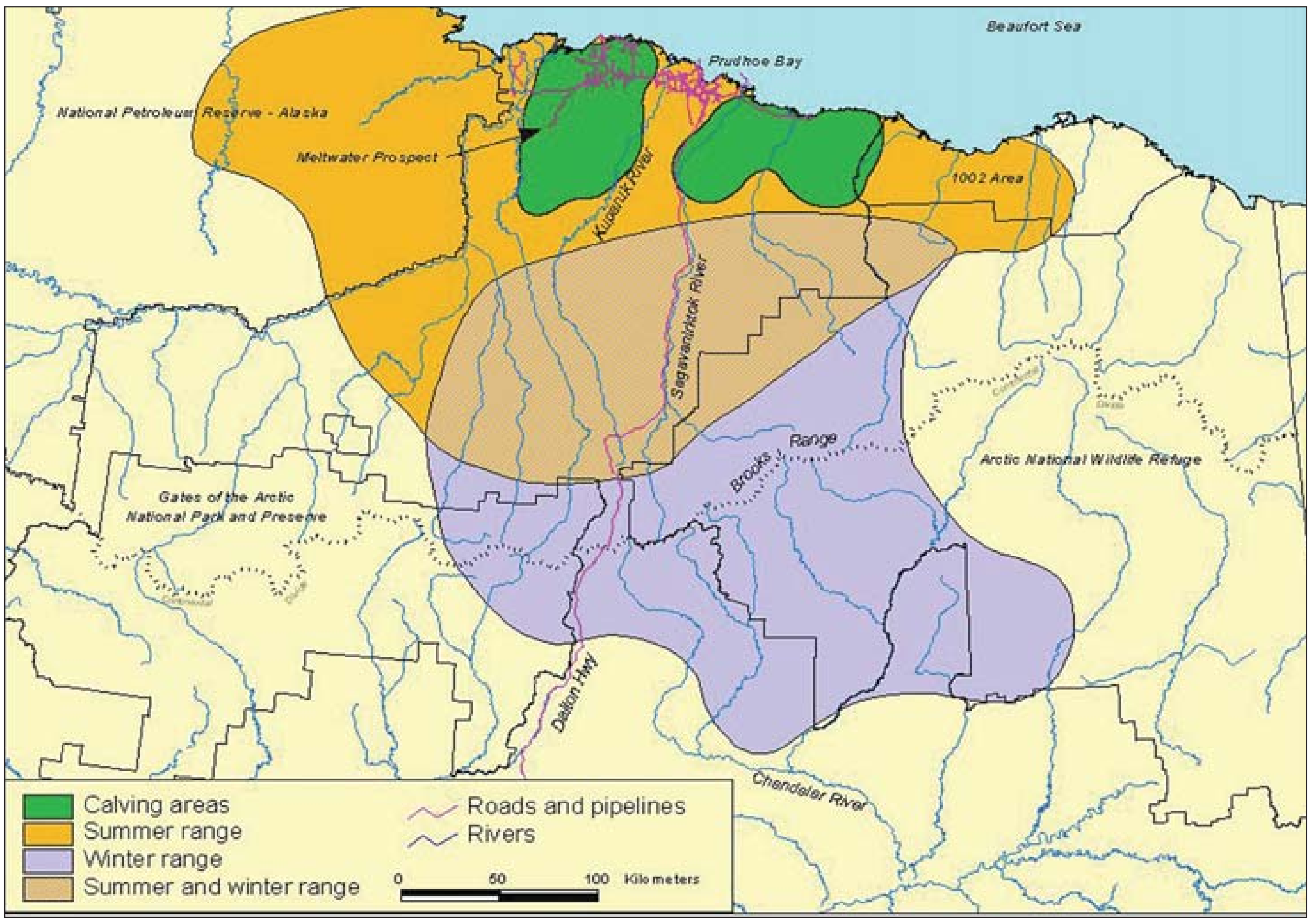
"It became clear to us that traffic was the prime stress in causing caribou to give up an attempt to cross a pipeline or a road. There were lots of trucks around, so traffic became the focus, and we studied traffic. We can't control traffic. But if we provide caribou with plenty of space, they can get under the pipeline, check out the traffic, wait for the traffic if they need to, and then pass," Joyce said.

The oil company soon realized that traffic management during caribou migration season would be necessary.

Other issues that greatly concerned the oil companies were how to allow the caribou unimpeded movement as they pursued their seasonal activities, and how to ensure that they maintained a healthy population and net production. Calving

see CARIBOU page 12

ALASKA DEPARTMENT OF FISH AND GAME



Seasonal ranges of the Central Arctic caribou herd.

continued from page 11

CARIBOU

has to occur at a spot that is beneficial to the herd, with minimal predators, good forage and low snow cover. So the animals use traditional patterns for calving. However, those patterns have changed over time.

From the 1980s through the 1990s, a shift in caribou calving occurred in the Kuparuk area. The bulk of calving now occurs to the south and west of the oil field. Some calving still occurs in the Milne Point and Kuparuk fields, but over a 20-year period, most of the calving has shifted further south, according to researchers.

Why? And even more important, said Joyce, "What does it mean?"

Today, researchers still don't know the answers to these questions.

Joyce said all kinds of variables influence caribou behavior from year to year — weather, snow and predators — all of which can cause stress within an area like Kuparuk.

But further study will help researchers get a feeling for whether the shift reflects a real problem, he said.

"Remember, our goal is healthy caribou populations — happy caribou," he observed.

Joyce also said the number of calves being dropped every year per 100 cows, from the late 1970s through 1999, showed a lot of between-year variability. But when researchers compared what was happening in the Central Arctic herd with other herds and other species, they found a fair amount of commonality in terms of down years, he said.

Herd growth unimpeded

The other component of "are the caribou happy and healthy?" depends on how the population is doing.

In 1972, when it was first recognized that the Central Arctic herd was a discrete group, there were only about 3,000 animals in the herd, Joyce said.

Over 30 years, the herd has grown ten-fold, with numbers currently exceeding 30,000 animals.

This growth pattern included a rather significant decline in the mid-90s that researchers still do not understand.

"We do know that there were a couple of hard winters at that point. We also know by looking at ungulates across the North Slope, that other caribou herds showed declines at about the same time. So this may have been weather-induced from those harsh winters. It is not clear," Joyce said.

"Which brings me to maybe the most important lesson I'd like to share with you," he told the technology conference in 2000. "For a disciplined wildlife scientist trying to figure out what the results are in terms of cause and effect, a couple of years of data doesn't help you answer those questions. We've been studying this caribou herd for over 25 years, and we still have questions about what is happening with this herd."

Joyce said it has taken a cooperative program working with government agencies, the North Slope Borough and village community residents, as well as some very powerful consultants with a lot of experience to try to gain the beginnings of an understanding.

Researchers agree that the discipline needs constant attention and surveillance and monitoring. The Central Arctic caribou herd is the perfect example of how important a continuous record of monitoring has been and will be for future oil development on the

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CARIBOU

North Slope, Joyce said.

Fields provide insect relief

Population numbers, however, can help explain what the calving distribution shift means.

In 2000, Joyce said he believed the herd's population was healthy, and that oil-field stress had caused no serious population-level disturbance at that point.

"We've talked about the fact that we also have learned behavior, habituation going on. For example, caribou need to go to the coastal plain for insect relief. They are harassed early by insects, and it's very important to move to avoid this. A learned behavior that we have seen over time is that our gravel fill provides secondary insect relief benefit to them," he said.

"You see a lot of caribou in the oil fields standing on the gravel pads with their noses down in the gravel to protect them from the insects' harassment early in the season. They have learned that there are fewer insects up on this gravel fill. It simulates coastal beach areas or gravel bars that they normally use for insect relief. So there is a learned behavior going on," Joyce said. "Remember that the herd was growing in the mid-1980s, so there are four or five generations or more of caribou that have grown up with Kuparuk. They've grown up with pads and pipelines and traffic, and there is a learned behavior and an adaptation, and I think there is some influence in what we currently see in terms of cause and effect on the caribou populations."

Monitoring the caribou over 30 years with the help of computer technology has enabled the oil companies to adapt their operations to successfully coexist with the Central Arctic herd.

Among the lessons the operators have learned: Keep pipe up off the tundra; try to minimize number and location of roads and try to not place them perpendicular to caribou movement patterns — try to go parallel as much as possible; and keep traffic down and control it during calving season. Ramps can be beneficial in key locations, but probably more important is giving the caribou space between pipes and roads.

Government has important role

Because the Alaska Department of Fish and Game is ultimately accountable to the public for the welfare of the Central Arctic herd, the agency scrutinizes any influences on the herd's sustained viability, and makes appropriate recommendations to land management agencies and to policy makers, according to ADF&G researcher Dick Shideler.

"One of the things we feel we really need is thorough pre-development studies — but only recently have we had really good before and after data," Shideler told the technology conference participants in 2000.

"But the bottom line for caribou calving is that the response of the caribou to the roads and facilities really does complicate what our mitigation options are for future oil fields. If they are so very reactive, it is essentially unrealistic to expect that an oil field the size of Kuparuk or Prudhoe Bay would shut down all traffic during calving, and in fact this might not be effective anyway. So we have to look at other options."

Fortunately, the physical size of oil fields has shrunk about 80 percent since Prudhoe Bay and Kuparuk were built.

As for the shift in proportional caribou habitat use, Shideler said there has always been some calving occurring in the hills south of Kuparuk, up through an area known as the Itkillik Hills.

"I can remember doing calving surveys with Ray Cameron in the mid-80s during heavy snow years on the coast, and we had a little more calving down in the southern parts of the field, south of Kuparuk. So some of the observed shift is probably related to snow conditions down on the coast," he said. "We do not feel that the caribou can't physically get to the calving area. There is no impediment to ewes crossing the pipeline and roads, but it really has more to do with their behavioral response."

Shideler said no oil development other than the tiny Badami site has occurred on the east side of the Sag River, so that area can be used as a semi-control of what has been happening on the west side of the river where the shift in calving has occurred.

"We have to remember that some caribou herds, like the Beverly herd for example, will go through major shifts in calving area almost annually. On the other hand, herds like the Western Arctic herd haven't significantly changed its

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(COURTESY CONOCOPHILLIPS ALASKA INC.)

This image of members of the Central Arctic caribou herd resting in the Kuparuk oil field on Alaska's North Slope has become an icon in the national debate over oil development in the Arctic.

Caribou thrive near Alaska's largest oil fields

When the Alaska Department of Fish and Game last took a count in July 2002, the Central Arctic caribou herd was thriving. The results of an aerial photo census pegged the herd population at 31,857 animals, up from 27,128 animals in 2000, an increase of 4,729 animals or 17 percent.

The caribou count was made from aerial photographs taken in July, at the height of the Arctic summer, on the Arctic Ocean coast where the animals bunch

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THRIVE

in groups of several thousand each for relief from pestering insects, according to Beth Lenart, an ADF&G biologist.

In summer, the Central Arctic herd migrates north from the south side of the Brooks Range, where it winters, to the Arctic Ocean. When the herd gathers on the Arctic coast, the department rushes a belly camera-equipped single-engine DeHavilland Beaver airplane to the scene to nab a series of photos for later analysis. As temperatures cool and the wind picks up, the animals drift inland from the coast and fan out. The range of the herd is bounded on the west by the Colville River and on the east by the Canning River.

Most of the current oil activity on the North Slope, including the Prudhoe Bay and Kuparuk oil fields, is within the range of the herd. The trans-Alaska oil pipeline and the Dalton Highway snake southward from Prudhoe Bay through the center of the herd's range.

Lenart said a healthy pregnancy rate and high calf survival contributed to the herd's success. The greatest hazards the animals face on the North Slope are the bugs and an occasional bear, she said. The animals also face predation by wolves on their annual trek into the mountains of the Brooks Range for the winter.

Some winters, the herd can be found on the west side of the Dalton Highway, Lenart said. ADF&G tracks the herd via radio transmitters on some of the animals.

537 percent increase over 28 years

The Central Arctic herd has grown from 5,000 animals in 1974, the early days of oil development on the North Slope, to almost 32,000 today — an increase of 26,857 animals or 537 percent over 28 years. Biologists don't know why the herd has grown so large.

Over the 28-year period of study, the herd size grew steadily with the exception of the 1995 count, when it dropped from about 24,000 animals to 18,000 animals in a three-year span.

When asked whether Alaska's caribou herd numbers are part of a natural fluctuating cycle, Pat Valkenberg, an ADF&G research coordinator, said in 2000 that it is one of the issues that caribou biologists periodically debate.

"In Alaska, in North America, some of the herds do appear to go up and down — some on a 20-year cycle. ... Other herds fluctuate fairly erratically. Other herds, such as the Porcupine, have been remarkably stable," Valkenberg said. Biologists venture that the reasons are partly weather related. Predator cycles might also contribute to fluctuations.

Four herds share North Slope

The Central Arctic herd shares the North Slope with three other herds, the Teshekpuk herd, the Western Arctic herd and the Porcupine herd, which wanders back and forth from the Arctic National Wildlife Refuge into Canada.

The Western Arctic and Porcupine herds have larger ranges than the Central Arctic herd, to the west and east, respectively.

The Teshekpuk herd, located northwest of Kuparuk and encompassing the city of Barrow, wanders a range of about the same size as the Central Arctic herd. The ranges of each of the three other herds overlap the edges of the Central Arctic herd's range. In recent years, the Central Arctic herd has occasionally crossed the Canning River into the Arctic National Wildlife Refuge, Lenart said.

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calving area in recent years, although its population has grown from 65,000 to almost a half a million animals in the past 25 to 30 years. The Teshekpuk herd hasn't changed much either," he told conference participants.

"From a biologist's standpoint, trying to integrate all of this conflicting information is difficult. The bottom line is we may never know why some of these trends occur," he added.

More study needed

Still, the question of what the shift in calving areas means remains unanswered for the Central Arctic caribou herd.

Hoping to find answers, ConocoPhillips Alaska Inc. and the Bureau of Land Management provided major funding for a five-year study of cows and newborn calves in the Central Arctic herd from 2001 to 2006. The National Park Service, U.S. Fish and Wildlife Service and state agencies also provided support.

Biologists Steve Arthur and Patricia Del Vecchio sought to identify and measure the mechanisms through which oil field development might affect the Central Arctic herd, such as by reducing body condition, reproductive success or calf survival.

In an interim research technical report, "Effects of Oil Field Development on Calf Production and Survival in the Central Arctic herd," published in March 2006, Arthur and Del Vecchio compare what happened to calves that were born in the two different calving areas, the mostly undeveloped area east of Prudhoe Bay and the area west of Prudhoe Bay that has seen increasing development since the late 1980s. In the western area, calving has shifted south since development began, though the researchers point out that it remains unclear if the shift resulted from development, increased herd size or other factors.

Arthur and Del Vecchio found that newborns from the western area on average weighed a little less and were slightly smaller than those from the eastern area, and that the differences persisted through at least the first nine months of life.

They concluded that the differences in size and mass of calves may be largely influenced by the quality of habitat and forage available to caribou cows during the calving period.

"Thus, displacement of caribou cows from preferred calving habitats may reduce fitness and survival of calves," they wrote.

Technology advances could help

One of the most interesting differences in this extensive study from ones conducted in the 1980s is the sophistication of the technology used today by the researchers.

Caribou cows were captured and fitted with collars containing satellite-linked GPS receivers programmed to determine their locations every five hours from May to October and every two days between November and April. Also newborn calves were captured and fitted with the radio collars every June. Location data was stored in the collars and relayed via uplink with the Argos satellite system once a week in winter and daily in summer.

Techniques used to analyze the GPS data collected in the study have not kept up with the ability to gather the data, so researchers focused on developing new techniques for better analysis.

They hope to look more closely at where caribou move and what habitat they use in relation to oil field infrastructure, they say.

Dave Yokel, wildlife biologist with the Bureau of Land Management, has said he's looking forward to that sort of analysis. "We hope we can use the results to mitigate any impacts on the Teshekpuk (caribou) herd from development in the NPR-A (National Petroleum Reserve-Alaska)," he told an ADF&G spokeswoman. "To do that, the BLM needs to know more about the impacts on caribou of movement through infrastructure."

Meanwhile, a 2002 photo census of the Central Arctic herd, the latest available, shows the herd's growth trend continues. The Alaska Department of Fish and Game's Division of Wildlife Conservation counted 31,857 caribou from photographs of the Central Arctic Caribou herd taken July 16, 2002. Groups and number of caribou were in the following locations: Katakturuk Point (115), Katakturuk Point (4,526), Canning River mouth (567), Shaviovik Delta (13,461), East channel Sagavanirktok River (1,962), Putuligayuk River (1,437), Sakonowyak River (3,299), Beechy Point (3,499) and Kaverarak Point (2,991).

"We located groups by radio-tracking collared caribou from a small fixed-wing Piper PA-18 aircraft and took photos of the groups using a 9-inch aerial mapping camera mounted in the belly of a DeHavilland Beaver aircraft," according to ADF&G researchers.

The CAH increased from 26,128 caribou in 2000 to an estimated minimum of 31, 857 caribou in 2002, reflecting an annual growth rate of approximately 8.5 percent.

"Parturition rates, late June calf-to-cow ratios, and fall calf-to-cow ratios were good in 2000 and 2001 and mortality rates also were low. Thus, it was not surprising that the CAH increased," the ADF&G said.

Though state biologists planned to count the herd every two or three years, they said no new census has been possible in recent years due to smoke from wildfires and cloudy weather. ●

SERVICE & SUPPLY

Canada's service sector looking sickly

Canadian natural gas industry in swoon, thousands of jobs disappearing; high storage levels, U.S. LNG imports part of grim outlook

By GARY PARK

For Petroleum News

The trickle-down effect has turned into a cascade, swamping some of the smaller Canadian oil and gas service and supply companies, especially those who overreached during the natural gas boom times of two years ago and are now reeling from a prolonged slump.

Barely 40 percent of the publicly traded service companies recorded profits in the second quarter and the overall group lost C$292 million, compared with earnings of almost C$450 million a year earlier when they were riding the wave of a record winter drilling season.

Since the start of 2007, 10,000 of 68,000 jobs in the service industry have disappeared and similar number have been lost among drilling contractors in one of the most punishing periods in recent years.

Don Herring, president of the Canadian Association of Oilwell Drilling Contractors, said laid off rig hands are moving into sectors such as the oil sands where pay increases are locked in.

As a result, even if conditions improve this winter, contractors will have a tough job attracting experienced workers.

Roger Soucy, president of the Petroleum Services Association of Canada, said the bloodletting will likely eliminate some companies, either through bankruptcy or mergers and acquisitions.

Smaller companies hardest hit

The heaviest toll will occur among smaller companies and trusts that responded to the drilling frenzy of two years ago, went on a capital spending spree and overextended their credit limits.

They are now paying the price, with drilling down 40 percent from a year ago and rig utilization at 36 percent in August compared with 65 percent a year ago, resulting in an equipment surplus and job shortage.

> *FirstEnergy analyst Kevin Lo said all of the factors at play — weak prices, bulging inventories, a strong Canadian dollar, spending cutbacks and a surplus of available rigs — point to an industry shake-out in 2008.*

Much of the attrition has stemmed from those companies that offered base salaries with bonuses for each job. As the contracts have faded so has the desire among many workers to stick around.

Soucy warned that such a trend poses a worry when a rebound takes place because many workers will have found jobs elsewhere and won't be anxious to rejoin the petroleum industry.

He said the greatest hope now is that problems created by warmer-than-usual winters will find an answer in a return to colder weather.

But the outlook for the gas sector is being portrayed by some analysts as flat-out dismal.

Canada can't match LNG prices

Paul Ziff, chief executive officer of the research firm Ziff Energy Group, said liquefied natural gas is arriving in the United States at prices Canadian producers can't match.

He told the Canadian Association of Drilling Engineers it will take a Herculean effort by the Canadian industry to roll back costs and regain its competitive edge.

Ziff said the Canadian gas sector is not experiencing a regular cycle, noting that the robust profits being posted by some oil and gas companies are inflated by returns from oil or old gas reserves that were cheaper to find.

As far as new gas reserves are concerned "we are probably under water," he said.

Ziff said that large volumes of LNG being dumped in the United States during summer to take advantage of large storage facilities that are not available elsewhere in the world further exacerbates the high costs in Canada.

He estimated that new Canadian gas reserves need prices close to US$8 per million British thermal units to be profitable, close to US$3 higher than recent prices in New York.

Ziff said the breakdown of costs for finding new reserves is 42 percent for drilling and well completions, 27 percent for land and seismic, 24 percent for operating costs and 7 percent for administrative expenses.

Gas inventories near glut

Martin King, a commodities analyst for FirstEnergy Capital, said North American gas inventories are rapidly closing in on last year's glut level, further undercutting any hopes of a rebound in the fall or winter.

He suggested there is unlikely to be a sustained uptick until well into next year given the latest trends, which include a drop of 3 percent in New York gas prices for August delivery to US$5.86, the lowest point since the end of December. Spot prices at the Alberta AECO hub were off 7 percent.

King said FirstEnergy is projecting October storage numbers will be more than 3.5 trillion cubic feet, less than 100 billion cubic feet from peak storage.

He said Canadian production is down 300 million cubic feet per day this year if viewed as a 12-month average and off 1 billion cubic feet per day on a month-over-month basis.

So far, there has been no sign of a price recovery to that decline because of the high storage level in the U.S. because Canadian supply losses have been offset by U.S. LNG imports.

FirstEnergy analyst Kevin Lo said all of the factors at play — weak prices, bulging inventories, a strong Canadian dollar, spending cutbacks and a surplus of available rigs — point to an industry shake-out in 2008.

He said a scaling back of equipment is needed given that the industry has enough capacity to drill 25,000 or more wells a year and forecasts suggest the total will be less than 20,000 next year. (PSAC is forecasting 17,650 wells in Canada this year, down 24 percent from 2006, and CAODC expects this year's well count will be short of its May prediction of 16,339).

Lo said the answer lies in a round of mergers and acquisitions during the winter drilling season

With some companies opting to sell rather than waste their cash resources, he said.

Lo said the rise in the Canadian dollar means AECO spot prices have not changed in five years and the current prices offer no support for additional drilling in Western Canada. ●

● FINANCE & ECONOMY

Upgraders in a bind

By GARY PARK
For Petroleum News

Proponents of new and expanded bitumen upgraders have just received a short, sharp message from investment dealer Peters & Co. Ltd. — they need oil prices of $70 per barrel West Texas Intermediate to achieve desirable economic returns.

In an oil sands review, Peters said it is "quite evident" that the rates of return on a standalone upgrader are "not favorable" at current oil prices and with a 30 percent differential between light and heavy crudes.

The study estimated the rate of return for independent upgraders is just 7.4 percent, based on today's oil prices, current price differentials and a construction cost of C$55,000 per daily barrel.

Given that a typical standalone steam-assisted gravity drainage project could generate a return of 14 percent in the current price environment, building an associated upgrader would cut into that return, Peters said.

The review said upgrading offers a bleaker outlook among the three components of the oil sands industry, trailing oil sands mining and SAGD.

Among the mining operations, the study estimates an oil price of $50 per barrel is needed for new mines that do not involve extensions of existing infrastructure.

But the report paints a positive picture for both mining and SAGD operations, suggesting the current futures oil strip of $68 a barrel until 2012 outweighs the rising breakeven costs, while SAGD projects should be economic with oil prices higher than $40 per barrel even though SAGD costs are climbing.

At present, BA Energy (77,500 barrels per day), North West Upgrading (150,000 bpd) and Peace River Oil (50,000 bpd) are at various stages of developing merchant upgraders. The Peters' report said these independent projects "will be challenged in this high-cost environment" based on the potential marginal economics.

Because of the demand for labor and materials, some projects are likely to be delayed or deferred, the review said.

Typical of the unease among upgrader proponents is France's Total, which is taking an even closer look at its plans for a 200,000 bpd (starting at 130,000 bpd) facility near Edmonton.

Michael Borrell, president of Total's Canadian subsidiary, told the Calgary Herald a study due for completion in the first quarter of 2008 will give a basic indication of cost and configuration.

He said the best way to ease the cost impact is to plan, engineer and factor in current market conditions, adding that Total's pre-engineering work will examine contracting and labor strategies. ●

FINANCE & ECONOMY

Northern crude line up for sale

A 40-year-old crude oil pipeline some think might have had a strategic role to play in carrying natural gas liquids from Canada's Arctic region has been offered for sale by three of the four corporate partners in the Mackenzie Gas Project.

Sister companies Imperial Oil and ExxonMobil, along with Royal Dutch Shell, have hired CIBC World Markets to market the 200,000 barrel per day Rainbow pipeline in northern Alberta.

The line covers 470 miles from Zama in northwestern Alberta to Edmonton, where it feeds into Enbridge's pipeline network to the U.S. Midwest and eastern Canada, as well as Kinder Morgan's Trans Mountain line to the Greater Vancouver area and Washington state refineries.

Imperial, acting as spokesman for the owners, did not put a price tag on the pipeline or explain why the asset was being unloaded. However, some observers think declining conventional oil production in Western Canada is likely a key reason.

There were also those who thought the Rainbow pipeline could have been the final link in delivering gas liquids from the Mackenzie Delta to market.

Currently, Enbridge is viewed as the frontrunner to build and operate a liquids line from the Delta to Norman Wells, where it would tie in with an underutilized crude system to Zama.

—GARY PARK

SERVICE & SUPPLY

Demand for offshore rigs escalates

GlobalSantaFe, Sevan order ultra-deepwater drill rigs ; 17 deepwater drillships now on order

By RAY TYSON
For Petroleum News

Demand for offshore drilling rigs capable of working in 10,000 feet of water continues to escalate, with Houston, Texas-based GlobalSantaFe and an affiliate of Norway's Sevan Marine ASA placing the most recent orders, totaling $1.14 billion.

Records show there are now 17 deepwater drillships on order or under construction and 40 in service worldwide. Additionally, 40 deepwater semi-submersible drilling rigs are on order or under construction and 167 in service. Many of the new-build orders were placed during the past few years, as oil prices strengthened and exploration and development activities moved into increasingly deeper waters.

GlobalSantaFe, awaiting shareholder and U.S. regulatory approval for its blockbuster merger with fellow offshore drilling major Transocean Inc., executed an agreement with Korea's Hyundai Heavy Industries Ltd., to build a new $740 million "ultra-deepwater" exploration and development drillship for delivery in September 2010, the company announced Sept. 11.

The new vessel, which is to be built in Ulsan, Korea, will be an enhanced version of GlobalSantaFe's GSF C.R. Luigs and GSF Jack Ryan drillships, which entered service in 2000. Like the Luigs and Ryan, the new rig will be capable of drilling in water depths up to 10,000 feet and could be upgraded to 12,000 feet, the company said.

The new rig also will feature advanced dynamic positioning capabilities, triple activity load paths, a derrick rated for 4 million pounds, dual liquid-storage systems, larger quarters and an efficient deck design that provides significantly more space than previous-generation drillships.

"This next-generation drillship resulted from listening to our customers, assessing the growing need for deepwater capacity and combining the best features of our drillships and semi-submersibles in a single unit capable of meeting our customers' full range of exploration and development drilling needs," said Jon Marshall, GlobalSantaFe's president and chief executive officer.

No drilling contract in hand

However, GlobalSantaFe is moving ahead with no drilling contract to support construction costs, a risk which "is clearly a departure from our much more conservative past approach," Marshall conceded.

He explained: "We would not have taken such a capital risk without a very high degree of confidence in the ongoing strength of the ultra-deepwater market."

Moreover, GlobalSantaFe's construction contract with Hyundai protects the company from rising costs, Marshall said, adding that he is confident of securing an "attractive long-term contract well in advance of delivery."

GlobalSantaFe merger partner Transocean already has ordered four ultra-deepwater drillships, while GlobalSantaFe previously ordered a semi-submersible rig. The two companies will have a combined market value of around $53 billion.

Meanwhile, Sevan Marine affiliate Sevan Drilling Pte Ltd. completed a $400 million financing package for its latest, sixth generation circular designed "ultra-deepwater" drilling rig, to be delivered to Brazil's Petrobras Americas at a yet undisclosed time in the future. The rig is to be named the Sevan Deepsea Driller

"We are pleased to announce this bank facility, which completes the financing of the advanced deepwater drilling unit … based on Sevan's own proprietary technology," said Jan Erik Tveteraas, Sevan Marine's chief executive officer.

Sevan Drilling signed the agreement for a senior debt project finance with Mandated Lead Arrangers GE Energy Financial Services, GE Transportation Finance and DVB Group Merchant Bank (Asia) Ltd. The facility, fully underwritten by the lead arrangers, is partially guaranteed by the Norwegian Export Credit Agency and is in the process of being syndicated to a limited group of international banks by GE Capital Markets, Sevan said. ●

The Sevan Deepsea Driller was designed after Sevan Marine's sixth generation technology.

FINANCE & ECONOMY

Oil prices baffle ExxonMobil boss

Rex Tillerson, rated the most powerful oilman in the world because he occupies the posts of chairman and chief executive officer at ExxonMobil, candidly admits he doesn't have a clue where oil prices are headed.

He told a Calgary audience Sept. 7 that today's price of US$70 per barrel is unjustified by fundamentals.

"I cannot explain why we have $70 oil," he said. "We are not having trouble finding oil. There is something else going on that I don't get."

But he conceded there is a need to both continue finding new energy sources and to diversify supply sources to ease the impact of supply disruptions.

"The nationality of energy is irrelevant," Tillerson said. "A diversity of sources mitigates the impact on total supply from disruptions in any region or any one source." He said that for the United States to adopt a policy of protectionism and isolationism could, based on history, be counterproductive, leading to "inefficiencies, higher prices, supply shortages and at times even trade wars."

Tillerson also attacked moves by Democrats in Congress to end tax breaks of $15 billion for companies exploring and producing oil overseas.

That would make companies like ExxonMobil and Chevron "less competitive in the international marketplace. It's upside down."

Hammering home his message of taking a global, rather than a national or continental approach to security of energy supply, he said that strategy will be vital as global demand for energy grows by 60 percent over the next 30 years, most of it coming from developing nations.

If the West's needs are to be satisfied, there must be a greater level of cooperation on a global scale, he said.

Tillerson, despite ExxonMobil's substantial writedown of assets in Venezuela, said it is better to deal with leaders like Hugo Chavez by offering western technological skills to help those countries expand their reserve bases.

—GARY PARK

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ARMSTRONG

"We are looking to get active in the Cook Inlet," Armstrong said. "We think it's a good time to explore for gas in the Cook Inlet. … So we made our first acquisition, and plan on working with other landowners in the Cook Inlet basin. We're looking forward to doing more deals. … Assuming we're successful, we'll be doing what was typical for us on the North Slope — a combination of wildcat and development drilling."

"To date most of the Cook Inlet basin explorers have been looking almost exclusively for structures. We'll be looking for typical structures, stratigraphic traps and a combination of both. … As long as people are willing to work with us, we'll be very busy," Armstrong said, noting that state and local officials had been very helpful in Armstrong Alaska LLC's exploration and development work on the North Slope.

Initially Armstrong CI will be working onshore. "We haven't decided yet about offshore," Armstrong said.

The Armstrong CI team will remain "essentially" the same, he said. The company's North Slope team included Ed Kerr, Stu Gustafson and Matt Furin.

Pursuing aggressive development

Armstrong CI amended North Fork's 42nd plan of development to pursue what it describes as "aggressive" development of the nonproducing unit's natural gas. The amended plan includes drilling a 9,000-foot Tyonek delineation well by March 31, 2008.

The "first order of business," Kerr said, is to get the delineation well drilled and a pipeline to KKPL built. "We can then prepare for the drilling and development of subsequent wells in order to fully develop the North Fork unit and any surrounding leases."

Kevin Banks, acting Division of Oil and Gas director, recently approved the amended plan, but said the 43rd plan of development for North Fork would be due by Jan. 1, 2008, which is about 90 days before the 42nd plan expires.

Under the original 42nd plan of development Gas-Pro was to put the existing North Fork gas well into production by Sept. 1, 2007. (The predecessor to Chevron, Standard Oil of California, drilled that discovery well, the North Fork 41-35, in 1965 while searching for oil.)

In a letter last month to the division, Armstrong Vice President Ed Kerr said related permitting and construction had not been done by Gas-Pro to meet the Sept. 1 deadline.

In exchange for putting the existing well into production right away, Armstrong CI proposed to drill a second delineation well in the spring, which Kerr said was needed to evaluate the Tyonek reservoir and insure "continuous uninterruptible commercial gas production."

Kerr said the "dominant theme" in Gas-Pro's plan of development was "to continue to look for gas markets and attempt to initiate sales of gas via trucking compressed natural gas and offloading said gas into the KKPL pipeline for sales." While Kerr conceded Gas-Pro's plan was "a valid option," he told the state that Armstrong CI did not think it was "the most efficient manner" to bring the North Fork unit into production because the plan did not propose to drill a second well in the unit.

Kerr also expressed concerned with the "potential liability associated with trucking compressed natural gas on Alaska highways," and with the fact that the process would "always be on an interruptible basis."

Talking to Enstar, Chugach, Agrium

Kerr said Armstrong CI has already begun discussing gas sales with area users, including "Enstar, Chugach and the Agrium plant." Those discussions have lead Armstrong CI to believe it will have a market for its gas once a pipeline is in place, he said.

"Enstar has stressed their need for gas moving forward beginning almost immediately and including very substantial volumes in the year 2010 and later," Kerr said. "Agrium has stated that they have a consistent need for gas while their plant is in use, which to date has been the 'off peak' months primarily in the summer. Chugach has also stated their need for gas both now and in the future."

Working to build a line to KKPL

Armstrong is also working on an "agreement in principle" with Enstar to build a 15-mile pipeline from North Fork's existing gas well to the KKPL, provided Armstrong is able to "drill and test a reasonable amount of gas out of the delineation well," Kerr told the state. KKPL is the most southerly gas pipeline on the Kenai Peninsula.

Kerr pointed out that no one has been able to persuade Enstar or any other party to construct a pipeline to the North Fork unit, largely because there is only one well in the unit.

"We are confident," Kerr wrote, "that after the drilling of the delineation well, we will have adequate reserves to warrant the building of a pipeline" to the North Fork unit. But if Enstar is not willing to build the pipeline, Kerr told the state Armstrong CI would be willing to conduct its own feasibility for building the pipeline.

In 2003, NorthStar Energy, which owns Gas-Pro, struck a deal with Enstar to supply gas from North Fork to Homer on the southern tip of the Kenai Peninsula. The deal involved Alliance Energy, a sister company to NorthStar, building a pipeline from North Fork to Anchor Point, northwest of Homer, and Enstar building a pipeline from Anchor Point to Homer, a total distance of 10-11 miles.

However, both Enstar and the Regulatory Commission of Alaska required that pipeline construction be contingent on drilling a second North Fork well, to raise proved reserves in the field from 12 billion cubic feet to 14.5 bcf, which would ensure a 20-year gas supply for Homer.

Gas-Pro never drilled the second well.

Armstrong's paperwork did not mention a gas line to Homer, but in July 2006 NorthStar informed Enstar that it could not meet the terms of the Homer gas supply contract.

In August 2006, Enstar told the Homer City Council that the company was considering building a high-pressure gas transmission line south from the end of the Kenai Kachemak Pipeline at Happy Valley to Homer. The new line would hook up to production from a known gas pool penetrated by the Red well in the Chevron-operated Nikolaevsk unit, close to North Fork. The line would cost about $16 million and take about four years to complete, Enstar said, which matches the 2010 date Enstar gave Armstrong.

In parallel with the construction of the gas transmission line, Enstar said it would start building out a gas distribution network centered on Homer, at an estimated cost of $14 million, to serve an estimated 3,000 customers in the Homer area.

Kerr says more wells, other projects to come

In its arguments to the state for amending North Fork's 42nd plan of development, Kerr said pointed out that there had been "no real exploration or development activity" in the North Fork unit or surrounding area for about 40 years, largely because of a lack of infrastructure (no pipeline) and a lack of a market for the gas.

The "first order of business," Kerr said, is to get the delineation well drilled and a pipeline to KKPL built. "We can then prepare for the drilling and development of subsequent wells in order to fully develop the North Fork unit and any surrounding leases."

In the section of his letter dealing with Armstrong CI's long-term plans, Kerr said North Fork was the first step for Armstrong CI "playing a larger part in providing natural gas to Southcentral Alaska."

He said he wasn't leaving

The three companies Armstrong Alaska brought to the North Slope in 2002-05 were Pioneer Natural Resources, Kerr-McGee and Eni Petroleum. Both the North Slope Oooguruk and Nikaitchuq discoveries were prospects Armstrong had identified, started permitting, and then helped drill and apply for development permits when Pioneer and Kerr-McGee, respectively, came in as majority partners and took over operatorship.

At the time Armstrong sold out its remaining North Slope assets to Eni, Bill Armstrong said, "We're definitely not leaving Alaska." He said the company would stay in the state and continue to put together exploration prospects, although at that time Armstrong's focus was still on the North Slope.●

ASSOCIATIONS

Streever to talk about 'Green Seduction'

The Alaska Association of Environmental Professionals has scheduled a lunch for Wednesday, Sept. 19, that will feature Dr. Bill Streever and his book, "Green Seduction."

The luncheon will be held at the BP Energy Center in Anchorage at 11:45 a.m.

Streever will discuss how America spends $230 billion a year on the environment, what we get for the money, and what you can do with this knowledge.

There is no charge but a scholarship donation is requested.

Call (907) 338-2238 for more information.

● NATURAL GAS

Canada gas producers hold line on spending

By GARY PARK

For Petroleum News

Spending on natural gas exploration in Canada next year is unlikely to change from this year's bleak performance and, if anything, could be further scaled back, company executives told a Peters & Co. conference Sept. 11.

EnCana and Canadian Natural Resources, the leading producers, say they have no plans to increase their budgets for 2008, while Talisman Energy and Husky Energy hint they could further trim their programs.

This bleak outlook comes amid the lowest rig utilization rates in Canada since 2002 and a 20 percent drop in Canadian gas prices since July.

EnCana Executive Vice President Mike Graham said the big independent's 2008 budget will likely be similar to 2007, with a slim chance it might be a "bit higher." But he said EnCana is "moderately bullish" on gas prices because of its belief that North America faces a supply crunch.

"It's tough to find gas and it's tough to replace it," Graham said.

To that end, he said EnCana is on the lookout to buy assets that are adjacent to its major operating areas, targeting junior firms who are suffering from low gas prices.

Gas exploration costs high

Canadian Natural Vice Chairman John Langille said it is difficult to divert money from oil to gas when gas exploration costs are so high in comparison to commodity prices. His company cut its gas spending in half this year to about C$1 billion from last year's C$2 billion and expects to hold that line into 2008.

Talisman's outgoing Chief Executive Officer Jim Buckee said his firm expects to reduce its exploration budget to C$1.5 billion in 2008 from this year's C$2.2 billion.

Husky's Chief Operating Officer Robert Peabody said his company is more likely to shift spending to other parts of its portfolio to "get more bang for our buck."

But he did offer one glimmer of long-term hope, saying Husky is "quietly positioning" itself to connect gas from Atlantic Canada's offshore to U.S. northeastern markets, although that is unlikely to happen before 2012.

He said Husky has identified 1.7 trillion cubic feet of gas reserves in the Jeanne d'Arc basin offshore Newfoundland and aims to establish 4-5 tcf to "create a material business" capable of serving U.S. customers. ●

EXPLORATION & PRODUCTION

Statoil sees 'heavy' answers abroad

Statoil is giving some definition to plans for turning its recently acquired North American "beachhead" into 200,000 barrels per day of synthetic crude production, helping the Norwegian giant sustain production at 1.2 million bpd until at least 2015.

Helge Lund, president and chief executive officer, said the company is on track for an initial 10,000 bpd of output from the Alberta oil sands no later than early 2010, climbing to its peak by 2020.

Having just acquired North American Oil Sands and 2.2 billion barrels of recoverable resource, Statoil is close to completing the second and third stages of front-end loading studies for its planned 200,000 bpd bitumen upgrader near Edmonton.

Until the company gets a better fix on capital costs it is reluctant to set a timetable for the upgrader. Neither is it ready to embark on further acquisitions until it develops what is already on its plate.

Lund said that as Statoil looks to diversify its global production, the oil sands have special appeal, because of their long-term nature, the political stability in Canada and the access to the world's largest oil consumer in the United States.

He said his company is also eager to strengthen its heavy oil portfolio, taking advantage of the knowledge it has gained from a 10 percent stake in Venezuela's Sincor project, a joint venture with France's Total and Venezuela's state-owned PDVSA that is aiming for 200,000 bpd of heavy oil.

Given that the Organization for Economic Cooperation and Development forecasts production from its 30 member nations will peak between 2010 and 2015 and the world will increasingly rely on Russia, the Middle East and Canada, Lund said it makes sense for international and state-owned companies to build their portfolios of unconventional resources. He is not deterred by the cost and labor pressures on the oil sands, noting that they exist on a global scale.

—GARY PARK

● INTERNATIONAL

China: Fund for risky gas projects proposed

PETROLEUM NEWS

According to a Sept. 13 MarketWatch report by David Winning, a Chinese official is urging his country to "set up a special fund to encourage its state oil companies to take on high-risk natural gas projects at home and overseas."

Bai Rongchun, the former director general of the National Development and Reform Commission's Energy Bureau, said Sept. 12 that a fund would contribute to resource security, especially since China's communities want clean energy and demand for natural gas is increasing from power generators and industrial users that are switching from oil and coal.

"China needs such a fund," Bai told attendees at the 2007 China Natural Gas Supply Forum in Beijing.

"If it's going to be established, then it should cover two areas — exploration in China and exploration overseas," Bai said.

Gas production from China's three oil and gas companies — PetroChina Co., China Petroleum & Chemical Corp. (Sinopec), and Cnooc Ltd. — is increasing annually "at double-digit rates, but not enough to keep pace with demand, as the fuel is cleaner than coal and cheaper than oil due to a state-controlled pricing mechanism," the MarketWatch report said.

Bai's comments, the article said, likely reflects "concerns among Beijing's leaders that state oil companies are willing to shelve plans to bring risky natural gas fields on stream because of the strain they put on exploration budgets."

For China, the world's second-largest energy consumer after the United States, "stimulating new investment in its natural gas sector is crucial if national targets for consumption of the cleaner fuel are to be met," MarketWatch said.

The article reported Bai said that a consensus hasn't been reached yet on the size of an exploration fund, but it "won't be very small" because of the high costs of exploring and developing natural gas prospects.

MarketWatch said it's "likely that the central government will take a lead role" in establishing a high-risk gas fund because it is looking "to put to use some of its $1.33 trillion in foreign exchange holdings at a time when China's energy insecurity is growing."

See the full article at www.marketwatch.com/news/story/china-official-urges-special-fund/story.aspx?guid=%7B720EE44F-3553-4310-A927-3E7BF05C2D42%7D ●

Companies involved in Alaska and northern Canada's oil and gas industry

All of the companies listed above advertise on a regular basis with Petroleum News

Petroleum news

Business Spotlight

FORREST CRANE

Mary E. Shields, President

Northwest Technical Services

Northwest Technical Services has provided quality contract and staff employees — professional, technical, administrative and craft — to Alaska companies for nearly 25 years. Its motto, "Connecting the right people to the right jobs at the right time," reflects the company's successful strategy. NWTS recruiters know their contractors' needs and seek a proper fit between employers and employees.

Mary Shields moved to Kenai, Alaska, in 1972 where she worked for ARCO and the Kenai Natives Association. She later joined NWTS in Anchorage, and nearly 20 years ago became general manager. Scuba diving and theatre are favorite activities. Mary enjoys being surrounded by her children and grandchildren, all living in Anchorage. A well-known civic and business leader, Mary actively supports organizations dedicated to the betterment of Alaska.

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COSTS

far behind original timetables, will likely take another year, at which point ExxonMobil will be able to provide an updated budget based on whatever conditions the project faces and decide whether to proceed, he said.

Until the regulatory rulings, engineering and field work are on hold, which means the cost estimate has "not had what I'd call a thorough update in some time," Tillerson said.

"There is no question that the cost has gone up, but we don't have a cost number that I have high confidence in," he said.

ExxonMobil is the key corporate decision-maker in the MGP, owning 69.6 percent of consortium leader Imperial Oil, which has a 34.4 percent interest, while wholly owned ExxonMobil Canada has another 5.2 percent.

Tillerson cautioned that the budget could be higher or lower than the C$16.2 billion figure, which was released in March and was up C$8.7 billion from the previous estimate.

"People need to be careful when you start throwing numbers around as to what is the quality of the cost estimate," he said, noting that costs across the energy industry have climbed "fairly dramatically."

"These costs were developed to work through the regulatory process.

"I wouldn't hang my hat on whether it's 16 billion, or 14 billion or 20 billion. All I would say, it's large, it's larger than we thought," he said.

Despite the regulatory delays and the inflated costs, Tillerson said "satisfactory" progress has been made on the regulatory front, discussions with the Canadian government are continuing and the project is still alive.

Tillerson: federal aid needed

He warned in May that the MGP would not be viable without a "sizeable chunk" of federal aid.

"The thing people have to appreciate is these are enormous investment projects," he said. "They will be among the largest investment projects undertaken anywhere in the world."

Meantime, the partners are looking for various ways to implement the project in a way that addresses the cost concerns.

Drawing on his own involvement over the past 20 years in both the Mackenzie and Alaska pipeline proposals, he said projects on those scales simply take a long time to bring together.

"Government and policy regulators have to appreciate these are enormous investment projects. They will be among the largest investment projects undertaken anywhere in the world," Tillerson said.

"Obviously there is a huge risk when you are putting that kind of capital upfront over your ability to get your money back and to generate some kind of acceptable return."

He said ExxonMobil is seeking a fiscal structure in Alaska that ensures stability for a project most recently estimated to cost US$25 billion.

He said the project will "take multiple years to execute before we see the first gas transported to the marketplace and then it will take a long time before you get your money back. That is why we need to have fiscal stability."

Tillerson said that although his company is ready to carry the resource risk and the risk of cost inflation, delays and gas prices, it expects the Alaska government to give a firm commitment on taxes and royalties.

—GARY PARK

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ARCTIC GAS

increasing to 6 bcf per day in 2020; initial volumes of 1.5 bcf per day from the Mackenzie Delta by 2013; and LNG from Russia and Norway.

The process also involved Energy and Environmental Analysis of Virginia, which ran two scenarios — one with and one without Arctic gas — to determine the impact of prices on North American consumers and the emissions that would result without Arctic gas.

Bell, in a presentation to the Center for Strategic and International Studies in Washington, D.C., said it is vital North Americans should know the cost of delaying the shipment of gas from the Arctic.

Speaking to reporters, he said the introduction of LNG imports to North America is not a threat to development of Alaska and Mackenzie Delta gas, noting: "We need it all."

Bell said Canada and the United States "must work together to develop a range of options."

'Integrated energy market'

Faced with some who suggested that if Arctic gas does not come on stream, the United States will simply turn to other sources of supply, he put emphasis on security of supply and the special relationship between Canada and the United States, which have developed a "fully integrated energy market that you can't find elsewhere."

He said the problem and the need for solutions is much bigger than simply telling people to turn off the lights when they leave a room.

Without Arctic gas and regardless of demand easing as gas prices rise, the study estimates there would be close to a 12 percent difference in gas prices over the nine year period.

"Arctic gas could lower consumers' cost of gas considerably in the years ahead," it said

Speaking in New York, Bell said MGP negotiations are at a "critical juncture," and he has "never been more concerned about anything than the costs and economics of the project and the negotiations that have to happen between the producers and Canada."

However, overriding everything is Bell's hope that the producers "have the will to see this thing through."

Bell: Government help needed

He said he pins much of his hopes on the Canadian government agreeing to help finance roads, bridges, airstrips and barge landings that are needed for the 720-mile pipeline along the Mackenzie River Valley and future "legacy infrastructure projects," as well as backstop loans to secure a one-third equity stake for the Aboriginal Pipeline Group.

Bell told a press briefing in Washington, D.C. the Canadian government, while it could contribute to the provision of "strategic infrastructure," is unlikely to offer any direct subsidies, but it is eager to work on other types of incentives, such as adjusting depreciation rates on investment in the pipeline.

He found some concern about the cost of developing Arctic gas, but also encountered a desire to reduce the reliance on coal and an acknowledgement that obtaining approval for nuclear power plants will face stiff public resistance. ●

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SHELL

No specific timeframe

Smith told Petroleum News Sept. 12 that Shell has not determined any specific time when the company would have to finally abandon its 2007 Beaufort Sea drilling plans.

"We're not there yet," Smith said, noting that sea ice and weather conditions determine the timeframe during which drilling can be done.

But meantime, Shell is starting to stand down its contract personnel, including workers on the Frontier Discoverer.

"Shell regrets it must take this action," Smith said. "As part of our 2007 exploration program we recruited and trained more than 700 talented personnel — among them roughly 350 Alaskans, 150 of whom are Alaska Natives. These dedicated people and jobs are important to Alaska and to Shell."

However, Shell is proceeding with its summer seismic program in the Chukchi and Beaufort Seas. Marine mammal observers and the staff manning the call center and communication center for that program remain employed, he said.

Local concerns

Native communities on the North Slope are concerned about the potential for offshore industrial activities to disrupt the annual subsistence hunt for marine mammals, in particular bowhead whales. And the North Slope Borough has consistently opposed offshore oil and gas exploration and development outside the barrier islands, because of concerns about potential impacts on subsistence hunting and possible environmental impacts.

The borough, the Alaska Eskimo Whaling Commission and several environmental organizations have appealed to the 9th Circuit Court the U.S. Minerals Management Service approval of Shell's Beaufort Sea exploration plan.

"The proposed exploration activities involve extensive drilling operations (involving multiple icebreakers, drilling platforms and aerial support) within the Beaufort Sea," the borough and AEWC said in their appeal petition. "These activities threaten to inflict significant and irreparable damage upon these subsistence resources and the communities they support without an adequate consideration of the environmental impacts. … Appellants have relied upon the harvest of bowhead whales for thousands of years for their subsistence way of life."

The Court imposed its temporary injunction on Shell's drilling program until the appeal is settled. And since the court schedule for the appeal extends into December, by which time sea ice will likely cover the Beaufort Sea, the injunction effectively means that Shell cannot drill in 2007.

Shell says that it has been working with North Slope communities to resolve concerns about its exploration plans. At the end of July the company signed a conflict avoidance agreement with the Alaska Eskimo Whaling Commission for the 2007 whaling season. That agreement included a commitment by Shell to cease drilling operations during the Cross Island whale hunt that occurs close to the drilling area.

"Shell recognizes the challenges of balancing cultural preservation against the need to exist in a cash economy, including the development of natural resources," Smith said. "This is a complicated issue for local communities and Shell stands ready to address these concerns." ●

ENVIRONMENT & SAFETY

Polar bear population seen declining

Two-thirds of the world's polar bears will be killed off by 2050 — and the entire population gone from Alaska — because of thinning sea ice from global warming in the Arctic, government scientists forecast Sept. 7.

Only in the northern Canadian Arctic islands and the west coast of Greenland are any of the world's 16,000 polar bears expected to survive through the end of the century, said the U.S. Geological Survey, which is the scientific arm of the Interior Department. USGS projects that polar bears during the next half-century will disappear along the north coasts of Alaska and Russia and lose 42 percent of the Arctic range they need to live in during summer in the Polar Basin when they hunt and breed.

"Projected changes in future sea ice conditions, if realized, will result in loss of approximately two-thirds of the world's current polar bear population by the mid 21st century," the report says.

Polar bears depend on sea ice as a platform for hunting seals, which is their primary food. They rarely catch seals on land or in open water.

"There is a definite link between changes in the sea ice and the welfare of polar bears," said USGS scientist Steven Amstrup, the lead author of the new studies. He said 84 percent of the scientific variables affecting the polar bear's fate was tied to changes in sea ice.

"In spite of any mitigation of greenhouse gases, we are going to see the same amount of energy in the system for at least 20, 30, 40 years," Mark Myers, the USGS director, said.

Greenland and Norway have the most polar bears, while a quarter of them live mainly in Alaska and travel to Canada and Russia. The agency says their range will shrink to no longer include Alaska and other southern regions.

The findings of U.S. and Canadian scientists are based on six months of new studies, during which the health of three polar bear groups and their dependency on Arctic sea ice were examined using "new and traditional models," Myers said.

USGS analysis was done to guide Interior Secretary Dirk Kempthorne's decision expected in January on his agency's proposal to add the polar bear to the government's endangered species list.

Last December, Kempthorne proposed designating polar bears as a "threatened" species deserving of federal protection under the Endangered Species Act. That category is second to "endangered" on the government's list of species believed most likely to become extinct.

—THE ASSOCIATED PRESS

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TRANSCANADA

to do so.

Asked when a decision could be expected from the board, Shapiro did not know, but she did say it would be in time for TransCanada to prepare an application and have it in by the state's Nov. 30 AGIA deadline.

Three pipeline companies — Enbridge, MidAmerican and TransCanada — have talked to the State of Alaska about building a natural gas pipeline.

Enbridge, another Calgary-based firm, has said it will not apply under AGIA because it believes the way to go forward with the project is in partnership with the North Slope producers who hold leases with most of the slope's discovered natural gas resources — including the gas in the producing Prudhoe Bay oil field where gas is being reinjected.

MidAmerican's testimony indicated it was the most interested of the three in pursuing an application under AGIA, which was reinforced this past summer when its chief executive said it would file an application with partners (unnamed) by the Nov. 30 deadline.

TransCanada said it did not want to go forward for a Federal Energy Regulatory Commission certificate if an initial binding open season failed to attract enough gas to justify the project. The norm in the industry, Tony Palmer, vice president of Alaska business development for TransCanada, told Alaska legislators in formal testimony, is to have customers before pursuing a FERC certificate. TransCanada's predecessor spent the money to get a FERC certificate for this project without customers in place, he said. "We did spend the money — when I say we, our predecessors spent the money 30 years ago — and we just would not like to repeat that process."

—KAY CASHMAN

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ANADARKO

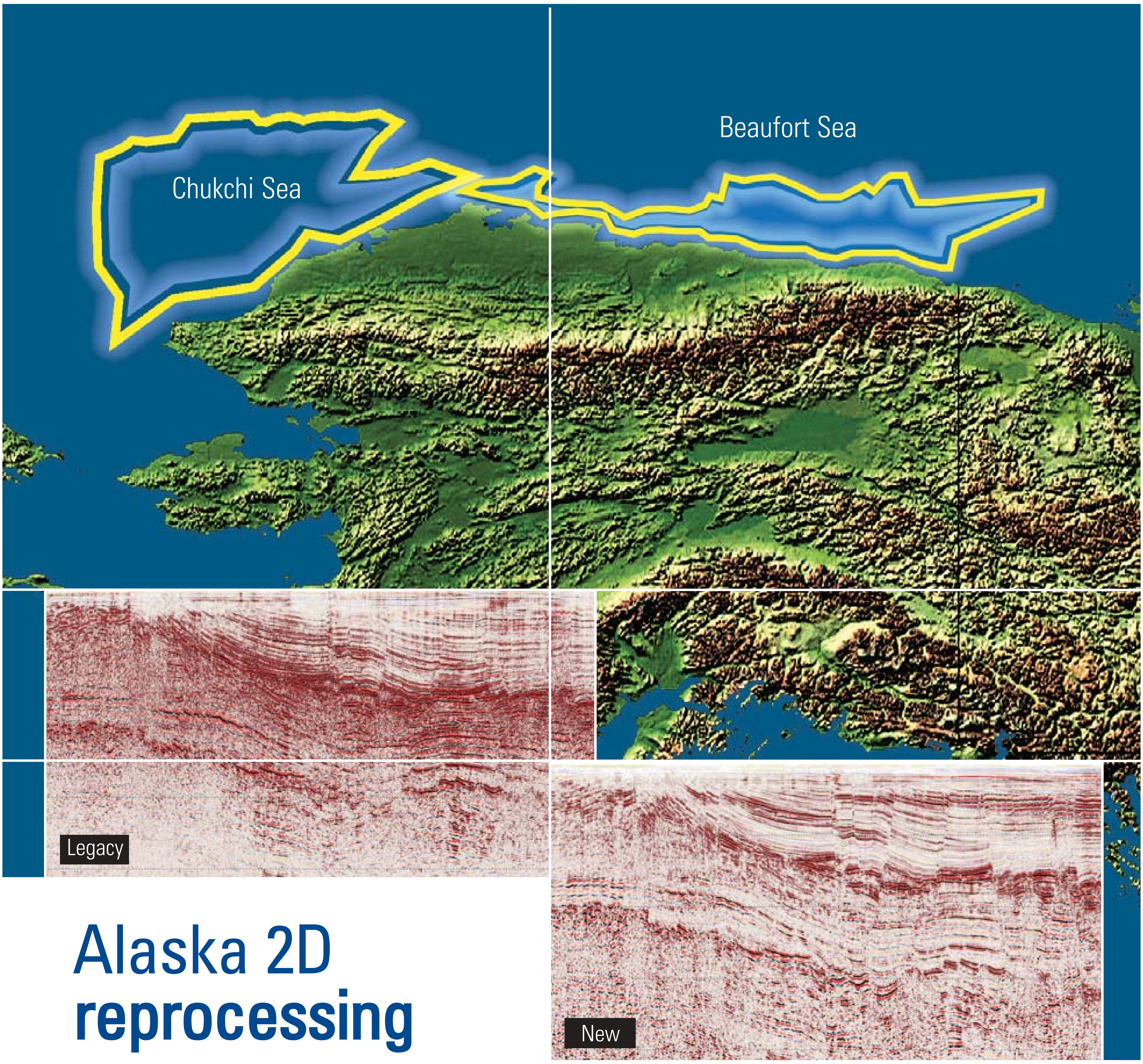
drilling rig, the Nabors rig 105, for the Foothills drilling program. The rig is under construction in Canada and is scheduled for delivery to the North Slope in December. Rig 105 is designed to be broken down into modules for transportation by rolligon, Mark Hanley, Anadarko's top official in Alaska, told Petroleum News earlier this year.

Although there is a known oil field at Umiat, the Foothills area is generally considered to be more favorable for the discovery of natural gas. According to the U.S. Geological Survey the Gubik field holds approximately 600 billion cubic feet of recoverable gas, and was discovered by the U.S. Navy more than 50 years ago while exploring for oil in the petroleum reserve.

Over the past few years Anadarko has talked about drilling a gas well, but before making the investment company officials wanted to be certain a gas pipeline would be built — and would accept gas under reasonable terms. Under the 2007 Alaska Gasline Inducement Act — i.e. AGIA — builders of a gas line from the North Slope have to treat all gas sellers fairly, even if gas owners BP, ConocoPhillips and ExxonMobil, competitors of companies such as Anadarko, win state approval under AGIA to build the line.

Hanley has in the past told Alaska legislators that nonowners of the gas line have to have access to the pipeline and know that the line would be expanded if they discovered new gas fields or developed known discoveries such as Gubik.

—ALAN BAILEY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