Petroleum news

page 15 Banks says 470 bcf of natural gas could be developed in existing fields

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Tugs, tanker in Alaska's PWS

COURTESY ALYESKA PIPELINE SERVICE CO.

Two Crowley tugs escort an oil tanker through Prince William Sound. One of the tugs is tethered to the tanker for the whole passage between the Valdez Marine Terminal and the entrance to the Gulf of Alaska. See story page 13.

Refinery shuts unit on declines; Senate considers gouging bill

The Flint Hills refinery shut down one of its three processing units because of declining demand for jet fuel, a company spokesman told a state Senate committee on March 13.

Crude Unit No. 3 produces jet fuel for Ted Stevens Anchorage International Airport, but a decline in landings at the busiest air cargo operation in the country, have reduced the demand for jet fuel, according to Jeff Cook, director of external affairs for Flint Hills.

Cook said international cargo flights at the airport are down 30 to 40 percent, and rail shipments from the North Pole refinery to Anchorage have fallen by half year over year.

> *"Our refinery is losing money again and the outlook is uncertain for the months ahead."*
> **—Jeff Cook, Flint Hills Refinery**

"We had no further capacity to store, and certainly weren't able to market the product," Cook said, calling the decision to shut down the crude unit "an unprecedented move."

Flint Hills built Crude Unit No. 3 in 1998 to meet increased jet fuel demand at the airport.

The unit accounts for a third of the production at the refinery, Cook said.

Cook said Flint Hill hoped the "temporary shutdown" would only last "three to four weeks," but that "world economics will determine how long that shut down takes place."

Those economics don't necessarily look favorable, though, Cook said.

"Our refinery is losing money again and the outlook is uncertain for the months ahead," he said.

Those poor economics led Flint Hills to enter into talks with the state Department of Natural Resources in hopes of finding a way to keep the refinery in business.

see **REFINERY** *page 22*

NATURAL GAS

Gubik tests 15 mmcf

Petro-Canada offers first glimpse of gas exploration program in Brooks Range

By ERIC LIDJI
Petroleum News

The first dedicated exploration well for natural gas in northern Alaska tested at rates of up to 15 million cubic feet per day, according to a partner in the drilling program.

Petro-Canada, a large Canadian oil and gas company, offered the figures in year-end documents filed with the U.S. Securities and Exchange Commission this morning.

Petro-Canada said drilling in the Brooks Range foothills in 2008 resulted in one well "completed as a natural gas discovery," and another "suspended for re-entry in 2009."

Although not named explicitly, Petro-Canada is certainly referring to the Gubik No. 3 and Chandler No. 1 wells drilled last winter in the region by Anadarko Petroleum.

> *"The development of discoveries in this area will depend on the establishment of pipeline infrastructure, including a possible intra-Alaska line running south to service the Fairbanks and Anchorage areas," Petro-Canada wrote in the year-end financial filings.*

Anadarko is the operator of a multiyear and wide-ranging search for natural gas across the state, federal and Native land in the western foothills of the Brooks Range, a package of natural gas prospects the company has begun calling the Gubik Complex.

see **GUBIK** *page 23*

GOVERNMENT

Russian bear comes prowling

Bombers intercepted just outside Canadian airspace; incident sets off prickly exchange, spurs Canada to seek common ground with US

By GARY PARK
For Petroleum News

Canada is raising an issue with the United States that has often soured relations between the two countries.

Foreign Affairs Minister Lawrence Cannon put the topic of Arctic sovereignty back on the bilateral agenda in February when he met with Secretary of State Hillary Clinton in Washington.

And he's expected to raise the volume even more when the two meet again this spring.

For Canada, achieving common ground with the U.S. has become even more urgent in the last month after two Russian bombers were intercepted just outside the Canadian Arctic shortly before President Barrack Obama's Feb. 19 visit to

> *Canadian government sources say Russia's drive to extend its border north by 150 miles and add about 20 percent to its oil and gas reserves, along with worries about a new Cold War, should give Cannon and Clinton the incentive to ensure that the Northwest Passage does not become the final stumbling block to the Arctic sovereignty debate.*

see **RUSSIA** *page 19*

NATURAL GAS

AGIA on the table again?

House Republicans want to revisit license decision; Palin wants to stay course

By KRISTEN NELSON
Petroleum News

SARAH PALIN

MIKE CHENAULT

Republican legislators in the Alaska House are concerned about current gas supply and price issues as they affect gas pipeline economics and want to be sure the TransCanada Alaska pipeline proposal the state is backing is still economic.

Two House Republicans have introduced a resolution asking for a re-evaluation of whether the award last year of a license to TransCanada Alaska under the Alaska Gasline Inducement Act, or AGIA, is still in the best interests of the state.

House Majority Leader Mike Chenault, R-Nikiski, said March 16 in a House majority press availability that with other gas supplies found in the Lower 48 and "the lower-than-expected gas price" it may be time to revisit the TransCanada license "and determine whether we should continue to put state funds on this project."

He also said that with open seasons for both the TransCanada Alaska project and Denali, the BP-ConocoPhillips joint venture, planned for next

see **AGIA** *page 21*

BREAKING NEWS

contents

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

● NATURAL GAS

State gas tax discussion continues in Senate

Stedman wants gas tax under ACES re-evaluated; administration doesn't see need to change, barring receipt new info from producers, pipeline; McGuire suggests study of issue in interim

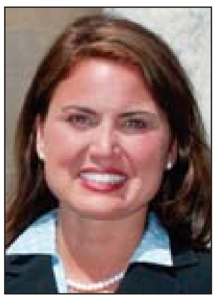
By **KRISTEN NELSON**
Petroleum News

Barring new information the Palin administration believes that Alaska's existing production tax system works for natural gas as well as for oil.

Legislators, however, aren't so sure.

Commissioner of Revenue Pat Galvin told Senate Resources March 11 that the administration has found the state's fiscal system under ACES as related to gas to be "entirely sound" and said it is "a structure that would support the development of our natural gas resources. It is crafted to protect the state's revenue both before and after gas commercialization."


PAT GALVIN


LESIL MCGUIRE

Senate Resources co-Chair Lesil McGuire, R-Anchorage, said she and co-Chair Bill Wielechowski, D-Anchorage, have talked with other members of the committee about discussing fiscal terms for natural gas in this session.

The Legislature revised the state's production tax system with passage of ACES, Alaska's Clear and Equitable Share, in late 2007.

Sen. Bert Stedman, R-Sitka, who was involved in both recent rewrites of the production tax, said he guessed they were agreeing to disagree. The Legislature has not signed off on ACES as a gas tax system, he said. Gas was removed from the first production tax rewrite done in the Murkowski administration, which "concentrated on dealing with the oil tax," and ACES had the same focus on oil, he said.

Stedman said a gas fiscal system needs to be addressed before open seasons for the gas pipeline, the first of which is scheduled for the summer of 2010.

Galvin said ACES provides incentives for developing the state's natural gas and "because the system provides that flexibility between a system where there is no gas production and one where there is gas production, we believe it provides the stable system that provides the durability that the companies are looking for in a fiscal system so that they have the confidence to move forward with gas commercialization under our current system."

Dueling models

The Alaska Legislature has committed not to change the gas tax regime after an open season — when natural gas is committed to a gas pipeline — but North Slope producers, who hold leases for known natural gas reserves on the North Slope, have consistently argued that ACES does not meet their need for stability in gas fiscal terms over the life of a gas pipeline project, and have said they need to negotiate a gas fiscal system with the state.

> **On the Web**
>
> See previous Petroleum News coverage:
>
> "ACES tax works for gas," in Feb. 8, 2009, issue at www.petroleumnews.com/pnads/284998051.shtml
>
> "Alaska gas tax quandary," in Dec. 21, 2008, issue at www.petroleumnews.com/pnads/938797534.shtml

Another objection to applying ACES to major North Slope gas sales was raised in December.

Dan Dickinson, a former Tax Division director working as a consultant for the Legislative Budget and Audit Committee, told legislators because gas has a lower value than oil, and ACES rolls the two into a single tax, the low value of gas would pull down the value of oil, reducing state revenues.

Using numbers from September, when Alaska North Slope crude oil was selling for around $80 a barrel and the Henry Hub spot price for natural gas was just above $6 per thousand cubic feet — and current volumes of oil and estimates of gas sales — Dickinson said the state would earn less revenue from sales of both oil and gas than it would from oil alone.

But Rich Ruggiero of Gaffney, Cline & Associates, a consulting firm which helped the state design ACES, told Senate Resources in early February that the numbers Dickinson chose to do the calculations were not typical of the price difference between oil and gas. He also said the current crude oil production volume Dickinson used in his calculation is about twice what the producers estimate it will be when natural gas begins to flow from the North Slope.

Ruggiero said the numbers in Dickinson's example would produce a temporary drop in revenues, but the relationship between oil and gas prices in that example have occurred only some 4 percent of the time in recent years.

It's an anomaly, Ruggiero said, and just one of tens of thousands of scenarios which could be run.

Ruggiero was back in Senate Resources March 11 to review how ACES works and the kind of results the administration expects when gas sales begin.

Always an oil and gas system

Galvin said ACES was built as an oil and gas system, a single system for both oil and gas. There was discussion, Galvin said, about separate systems for taxing oil and gas, and about the "the complications that that would create in regard to allocation of costs and other things that were seen as detrimental to a stable system if we were going to separate" oil and gas in the taxation system. With oil and gas taxed separately, costs would have to be allocated to either oil or gas and there is concern that this would provide opportunity to game the system and would complicate the state's auditing of tax returns.

Galvin said that how ACES would work when both oil and gas were being taxed "is not something that we ignored" during ACES consideration, but he acknowledged that how ACES would work when both oil and gas were being taxed "wasn't part of the public discussion" when ACES was passed.

Galvin said the administration recognized "it would be part of the discussion ... closer to gas commercialization."

When the administration analyzed ACES as part of the Alaska Gasline Inducement Act analysis, it found ACES "is a very robust system" and would work when the state was taxing a mixture of oil and gas.

see **GAS TAX** page 23

FINANCE & ECONOMY

Shell looks to energy growth in future

Shell is continuing to invest in bringing new oil and gas online, reflecting the company's view that energy demand will climb in the long term despite the current economic problems, company executives said March 17 when introducing Shell's annual business strategy update. The company is treading carefully through a situation in which, although long-term prospects look good, a downturn in energy prices is occurring during a period when operating costs are high, the executives said.

"These are testing times in the oil and gas industry," said Shell Chief Executive Jeroen van der Veer. "Whilst short-term measures are important, we keep our long-term perspective, and continue to believe that energy needs over the long term provide a positive context for Shell's investment programs today."

Faced with declining production from its existing fields, Shell needs to find and produce new oil and gas, while in the downstream end of the company's business Shell needs to balance the demand for cleaner products with supply cost challenges, van der Veer said.

The company anticipates investments already under way in new oil and gas production to generate 2 to 3 percent annual production growth early in the next decade, he said. And development options where the company has not yet made final investment decisions could add more than 1 million barrels of oil equivalent per day to Shell's production capacity, from resources that could sustain growth until at least 2020.

"The economic slowdown creates opportunities for Shell to reduce supply-chain costs, as spare capacity in the services industry comes into play," van der Veer said. "We don't have a crystal ball on oil prices, so we are planning on the basis that the downturn could last more than a year."

—ALAN BAILEY

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● FINANCE & ECONOMY

Oil hits high for 2009 as dollar plunges

Despite increasing jobless claims and fewer highway miles, oil rises on Fed decision to buy bonds, lend to small businesses

By CHRIS KAHN
The Associated Press

Oil prices hit new highs for the year on March 19 after a decision by the Federal Reserve to spend billions snapping up U.S. bonds sent the dollar tumbling.

Oil is priced in dollars and when the U.S. currency weakens, it essentially makes crude cheaper.

Benchmark crude for April delivery surged $3.12 to $51.26 a barrel in light trading on the New York Mercantile Exchange. Oil prices hit $52.25 earlier in the day, a price last seen on Dec. 1. Crude prices have touched new highs every day since OPEC ministers met in Vienna on March 15.

With the April contract set to expire on March 20, most of the trading had shifted to the contract for May delivery, where prices jumped $2.85 to $51.75 a barrel.

Alaska North Slope crude oil delivered to the West Coast closed at $47.14 a barrel on March 18.

Analysts said investors flocked to crude stocks after the Federal Reserve announced on March 18 it would buy long-term government bonds, a measure that's expected to jolt the economy with lower rates on mortgages and other consumer debt.

Price jump follows fed news

The Fed also said a $1 trillion program to jump-start consumer and small business lending could be expanded to include other financial assets.

"You're seeing wild swings in a lot of commodities today," said Phil Flynn, analyst at Alaron Trading Corp. "The government is basically printing money to buy back all this paper, and it devalues the dollar."

The U.S. dollar dropped against other major currencies almost immediately, at one point falling to levels not seen since January. On March 19, the euro traded at $1.3650, up close to 2 cents.

Flynn said the rise in oil shouldn't be taken as a sign that the economy in on the mend. The Fed is using all of its powers to prop up American businesses, "and this is one of their last shots," Flynn said. "If this doesn't work, they're out of bullets."

OPEC cuts finally take hold

While demand continues to fall, production cuts by the Organization of the Petroleum Exporting Countries may finally be taking hold, according to tanker tracker Oil Movements. Member states agreed last year to squeeze global oil supplies, trimming 4.2 million barrels per day in production.

Crude exports from OPEC countries have been shrinking during the past few months. They're expected to drop 770,000 barrels a day in the four weeks leading to April 4, according to an Oil Movements report.

While the recession kept oil near five-year lows, tighter supplies in the spring and summer should buoy crude prices in the next three months, the report said.

Prices rises despite economy

Oil prices spiked on March 19 despite a government report that said jobless claims set a new record for the eighth straight week. The Labor Department said continuing claims for unemployment insurance jumped 185,000 to a seasonally adjusted 5.47 million, another record-high and more than the roughly 5.33 million that economists expected.

Initial claims dropped to a seasonally adjusted 646,000 from the previous week's revised figure of 658,000, however. That was better than analysts' expectations.

Job cuts are part of the reason for a severe drop-off in miles driven by Americans, a growing number whom no longer commute to work.

The Federal Highway Administration said on March 19 that motorists logged 7 billion fewer miles in January, 3.1 percent less than the same period in 2008.

The dour economic news did little to dissuade investors as prices topped $50.47 a barrel, the previous high for 2009.

Cameron Hanover analyst Peter Beutel said if crude sets a new high for the year at the close of trading, it means that OPEC production cuts, the federal stimulus package and other bullish factors "are working together to be more important at this moment than the recession and its impact on demand." ●

Associated Press writers Ernest Scheyder in New York, George Jahn in Vienna, Austria and Alex Kennedy in Singapore contributed to this report.

CORRECTION

The article entitled "Drift River Terminal ready for anything" in the March 15 issue of Petroleum News incorrectly spelled the name of Chevron Pipe Line Co.'s team leader who manages the terminal. His name is Rod Ficken, not Rod Flicken.

NATURAL GAS

British Columbia: Touting the Horn

Spectra gets producer backing for 'significant' expansion of BC gathering, processing facilities; government pumps more into roads

By GARY PARK

For Petroleum News

Shrugging off concerns that British Columbia's resource-rich shale gas will have a tough job competing over the near term with the prolific Haynesville shale in Texas and Louisiana, production, pipeline and processing companies are wasting no time putting an infrastructure in place.

In the latest development, Spectra Energy said March 12 it has rounded up firm, long-term commitments from seven unidentified Horn River producers for a "significant" expansion of its gathering and processing facilities in the Fort Nelson area.

Work on the multiphase expansion is scheduled to start this year and continue into 2012.

Spectra already operates a 1 billion-cubic-foot-per-day Fort Nelson gas plant, which has been in service for more than 40 years, but is currently running at less than half of capacity.

Duane Rae, Spectra's vice president of field services, said the first order of business is to fill up the Fort Nelson plant.

But that requires a "substantial investment" in both processing and transportation capacity, he said, although cost estimates are not being disclosed at this time.

The expansion plans include reactivating existing processing capacity at the Fort Nelson plant, looping and reconfiguring some of the 600 miles of pipelines in the Horn River basin and adding new processing capacity at a compressor station.

Without additional compression and processing capacity, Spectra said the Fort Nelson plant could be increased to 1.1 bcf per day.

Largest sour gas facility in NA

The plant is the largest sour gas processing facility in North America and the only one handling Horn River gas.

Rae said the producer commitments set the stage for a "substantial investment" in Fort Nelson infrastructure that could lead to 830 million cubic feet per day of incremental expansion capacity.

He said Spectra is in discussions with other Horn River producers to further increase capacity of the facility.

Gas from Fort Nelson is intended for transportation south and east on Spectra's mainline in British Columbia, but Spectra has not yet decided which direction will get priority when it files a regulatory application with the National Energy Board this spring.

Rae said the commitments from producers "signal to us that they are serious about developing this resource."

The expansion plans include reactivating existing processing capacity at the Fort Nelson plant, looping and reconfiguring some of the 600 miles of pipelines in the Horn River basin and adding new processing capacity at a compressor station.

Spectra had previously announced that it executed service agreements with customers for a proposed expansion of its gas transmission facilities in northeastern British Columbia.

That work is designed to add 153 million cubic feet per day of eastbound deliveries from its McMahon plant to interconnections with the TransCanada and Alliance pipelines to eastern Canada and the United States.

It will also boost westbound capacity by 112 million cubic feet per day to an interconnection with Spectra's southern transmission system.

TransCanada has commitments

While the potential in Horn River and the Montney tight gas play to the south are not being disputed, some observers have noted that initially northeastern British Columbia will be at a disadvantage against Haynesville, where existing infrastructure and access to markets is estimated to offer a saving of C$1-$1.50 per thousand cubic feet in transportation costs.

The Spectra announcement came just two weeks after TransCanada said it had commitments of 378 million cubic feet per day to support a new C$340 million pipeline from Horn River to a tie-in point on its Alberta network, with an operational date of mid-2011.

The British Columbia government gave a further boost March 13 to its largely untapped northeastern basins.

It said that starting in the current fiscal year it will spend C$187 million to improve about 105 miles of roads into the Horn River basin and Cordova Embayment areas.

Energy Minister Blair Lekstrom said the project would create 1,150 jobs and was proof of his government's commitment to provide the infrastructure "needed to develop the unconventional gas resources in our province."

The four-year undertaking will improve and extend the road from Fort Nelson to the Alberta border. ●

New entry in B.C. LNG field

Take your pick — it's either shaping up as a rival or an extra.

Whatever the choice, the pieces seem to be coming together for a second LNG export terminal at Kitimat on the northern British Columbia coast.

In separate, back-to-back agreements with Merrill Lynch Commodities, Pacific Northern Gas and Teekay Corp. have laid the groundwork for a possible project.

Meanwhile, Kitimat LNG is seeking partners for a liquefaction terminal at Kitimat with plans to ship LNG to Asian markets.

The deals with Merrill Lynch involve a tentative contract for 75 million cubic feet per day of firm gas transportation service using existing capacity on PNG's Western British Columbia pipeline system and plans to convert a ship into a floating LNG plant to be moored alongside a pier near Kitimat.

Merrill Lynch has deposited a C$1.5 million non-refundable option fee into an escrow account that will be released to PNG once the British Columbia Utilities Commission has approved a letter of agreement.

Merrill Lynch will have an exclusive option until Dec. 31 to contract for firm gas transportation capacity for a primary term of two to five years, with the right to renew for an additional two to five years. Alternatively, it may extend the initial option period by up to four- to six-month periods by paying C$1 million for each extension.

If Merrill Lynch exercises its option, the PNG pipeline system would be at full capacity utilization, generating almost C$15 million per year of incremental revenue for PNG and its customers. The startup date for transportation service is expected to be between Jan. 1, 2012, and Jan. 1, 2013.PNG is continuing to develop a pipeline to Kitimat through its interest in Pacific Trail Pipelines Limited Partnership.

The agreement with Teekay involves the joint development of a project to convert the S/S Arctic Spirit into a floating LNG plant, with Teekay LNG Partners having an option to participate in the project.

The converted vessel would have capacity to liquefy 75 million to 100 million cubic feet per day of pipeline quality gas, or about 500,000 metric tons per year of LNG, which could then be offloaded to other carriers for export.

Mark Kremin, Teekay's vice president of gas services, said, "Reliable Canadian LNG supply should be very attractive for LNG buyers and end users."

"This development will prove the feasibility of floating liquefaction and will provide an option for monetizing stranded gas resources in other parts of the world."

Subject to regulatory and other approvals, the project is expected to start LNG operations in 2012.

With a fleet of 180 vessels, Teekay said it transports more than 10 percent of the world's seaborne oil and has built a presence in the LNG shipping sector through Teekay LNG Partners.

Kitimat LNG is still seeking producer backing for a possible C$4.2 billion terminal to handle 3.5 million to 5 million metric tons per year of LNG.

Mitsubishi has signed a tentative agreement to acquire a minority stake in the project covering 1.5 million metric tons per year of capacity.

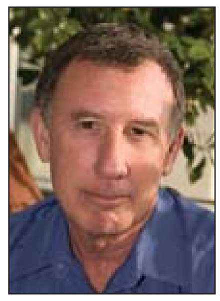
—GARY PARK

NATURAL GAS

BLM names gas pipeline project manager

The Bureau of Land Management in Alaska said March 13 that Ron Dunton has been appointed gas pipeline project manager.

Dunton, a former BLM land and resources manager from New Mexico, will oversee the development and processing of gas pipeline applications submitted to BLM for activities on federal land. BLM will be involved in developing environmental analyses and granting rights of way for proposed gas pipelines on federal lands.



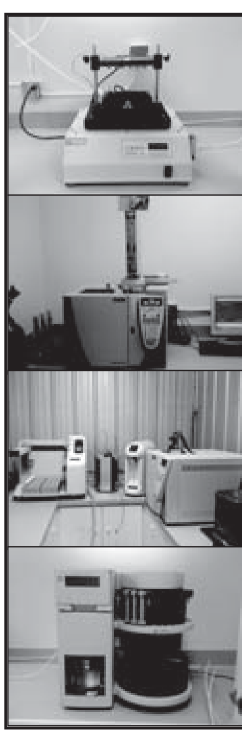
RON DUNTON

Dunton began his federal career with BLM in 1969 working on a helitac crew for the Alaska Fire Service in Fairbanks. Before returning to Alaska, he recently served as the deputy state director for Lands and Resources in the BLM New Mexico State Office. He also completed a six-month detail in the Department of the Interior in Washington, D.C., as the acting director of the Office of Wildland Fire Coordination. He has served as BLM national fire program manager and as a resource manager in Socorro and Carlsbad field offices in New Mexico.

"Ron has in-depth experience in land and resource management," Alaska State Director Tom Lonnie said in a statement, "and his experience as a manager and his ability to build relationships with BLM's customers is what we need in this position."

Dunton began work at the BLM Alaska State Office in Anchorage March 9.

—PETROLEUM NEWS



● SAFETY & ENVIRONMENT

BLM starts work on Atigaru Point well

Cleanup efforts begin on third in program to prevent environmental damage at 'legacy wells'; funding uncertain for fourth well

By ERIC LIDJI

Petroleum News

The federal government is tackling another decades-old well site that poses a threat to the environment because of eroding coastlines and thawing permafrost on the North Slope.

The Bureau of Land Management in late February began remediation work on the Atigaru Point No. 1 well site, situated some 30 miles northwest of Nuiqsut at the tip of a peninsula in the National Petroleum Reserve-Alaska that juts into Harrison Bay.

Atigaru is the third effort in a BLM program to prevent "legacy wells" across NPR-A from damaging the environment. Like Atigaru, the previous wells also sat near coastlines.

Receding coastlines threaten to dump the contents of these well sites, which contain diesel fuel and drilling mud, into nearby lakes, oceans or bays on the North Slope.

This changing landscape put Atigaru in a precarious situation.

Naval crews considering drilling locations in Naval Petroleum Reserve No. 4 in the late 1970s, the final years before the area became known as NPR-A, ultimately sited an exploration well as far out on the tip of Atigaru Point as possible, hoping to reach a geologic formation encountered by a well to the west and the Prudhoe Bay field farther to the east.

The U.S. Navy eventually drilled Atigaru in 1977 to a total depth of 11,535 feet.

Today, the eroding coastline in the Atigaru area has turned the well site from a peninsula to an island, and a "major summer storm" could potentially cause "low-lying areas" to crumble, dumping drilling mud and diesel fuel into the water, according to BLM.

The cleanup effort began Feb. 27 and is slated to run through mid-April.

BLM expects the project to cost about $15 million, with funds redirected from within the agency last fall in an emergency request outside the normal funding cycle.

The work involves excavating oil-based drilling mud, which is also believed to contain heavy metals, from the reserve pit at Atigaru Point and trucking it to the North Kalikpik No. 1 well site about 15 miles to the southwest. Crews will also drain some 14,000 gallons of diesel fuel currently stored inside the Atigaru well bore to prevent freezing.

BLM hired Marsh Creek LLC to carry out the work.

Nearing end of project

BLM, an arm of the U.S. Department of the Interior, has been managing NPR-A legacy wells for decades, but only began focusing on emergency cases over the past few years.

The recent push began in adventurous fashion in 2005, when BLM crews set out to remediate the J.W. Dalton No. 1 well north of Teshekpuk Lake. The U.S. Geological Survey drilled the well 1,500 feet from the Beaufort Sea coastline in 1979. In September 2004 crews discovered the coastline had eroded all the way back to the well and rushed to clean up the site before waves crashed over the area.

Following work at J.W. Dalton, BLM began prioritizing other legacy wells by the likelihood each might become an environmental hazard through the end of the decade.

The program continued last winter with the East Teshekpuk No. 1 well, located along the eastern edge of Teshekpuk Lake. Marsh Creek also cleaned up the East Teshekpuk well.

After finishing Atigaru Point this year, BLM hopes to address the Drew Point No. 1 well, northwest of Teshekpuk Lake, but funding for the project remains uncertain.

BLM received $320 million from the American Recovery and Reinvestment Act, also known as the stimulus bill, but the money hasn't been appropriated for specific projects, according to Wayne Svejnoha, environmental program manager for BLM in Alaska.

Drew Point is the last of the legacy well sites believed to be an immediate threat to the environment because of coastal erosion. After Drew Point, BLM does not anticipate having to address another legacy well for at least a decade, Svejnoha said, although several well sites further inland could require remediation sometime in the future.

Possible candidates include the Tulageak and West Dease wells, east of Barrow.

In excursions between 1944 and 1953, and between 1975 and 1982, the U.S. Navy and the USGS drilled 136 wells in what is now the National Petroleum Reserve-Alaska.

BLM believes 41 of these wells could "pose a potential risk to the environment" and has cleaned up 13 since 2002. The agency hopes to tackle 13 over the next five or six years. ●

Contact Eric Lidji at 907-522-9469 or elidji@petroleumnews.com

● EXPLORATION & PRODUCTION

Newfoundland: Dealing with a tragedy

Province reels from loss of 17 in helicopter ditching; pushes ahead with exploration; weighs initial gas project royalty holiday

By GARY PARK

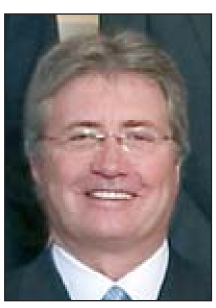
For Petroleum News

It might have been a time of quiet celebration and a mood of hope for the future of Newfoundland's offshore oil and gas industry.

Instead, it was the worst of all times, with the deaths of 17 rig workers and flight crew in the March 12 ditching of a helicopter in the North Atlantic, leaving only one survivor in critical, but stable condition.

The province's worst offshore oil disaster occurred 27 years ago when the Ocean Ranger, then the world's largest semisubmersible rig, capsized and sank on the Grand Banks with the loss of all 84 who were aboard.

Bringing Newfoundland into commercial oil production has always been an odds-defying struggle with rising costs, spotty exploration results, the departure of major exploration companies, squabbling over royalties and the unrelenting challenge of operating in stormy, iceberg-infested waters.



DANNY WILLIAMS

But a handful of producers has plugged on and just recently observed a milestone, when combined output from the Hibernia, Terra Nova and White Rose fields passed 1 billion barrels.

For a province that has carried Canada's heaviest burden of unemployment during its 60 years as a member of the Canadian confederation, the offshore has at least partly offset the loss of a fishery and the decline of a mining industry.

The industry has provided thousands of construction and rig jobs and generated more than C$5 billion in royalties since 1997.

Price has been high

Yet the price has been high, as Premier Danny Williams said in describing the "terrible tragedy off our shores."

He said Newfoundlanders have for centuries risked their lives "to provide for their families and contribute to this province. And yet, we will never, ever be able to accept the loss of precious lives to the sea."

The March 12 crash involved a Sikorsky S-92 helicopter from a fleet of three operated by Cougar Helicopters, which ferries workers to and from the offshore rigs.

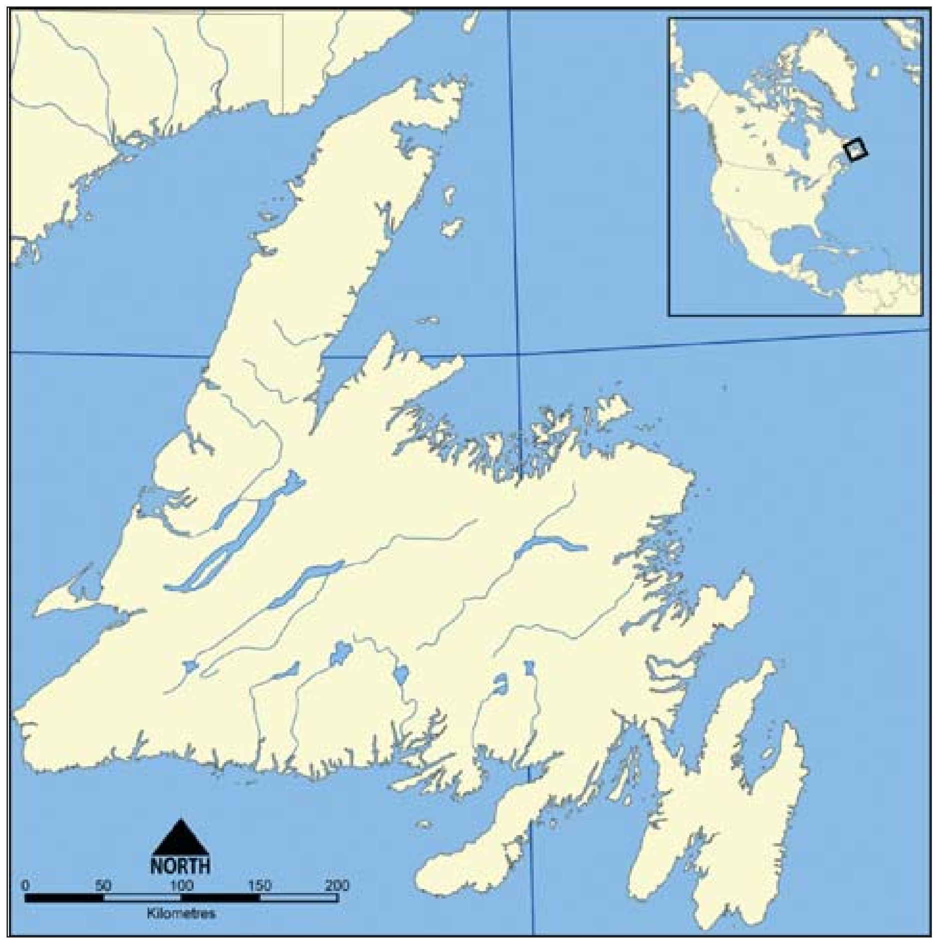
Just minutes into a 240-mile flight the pilot reported that he was experiencing a "main gear box oil pressure problem" and was returning to shore. That was quickly followed by a Mayday call.

While the fuselage was being recovered from about 400 feet of water, a team of 20 investigators — 12 from Canada's Transportation Safety Board and eight from the United States — was probing the cause of the crash.

Cougar Helicopters aircraft have had no accidents and no fatalities in nearly 50,000 flight hours over 10 years of serving the offshore, but a Transport Canada database says the company's S-92 helicopters have been involved in 10 "occurrence" reports on or near Newfoundland's coast in the past year.

Building blocks assembled

As it comes to terms with the tragedy, Newfoundland is also assembling the building blocks for a robust offshore.



The White Rose partnership, operated by Husky Energy, is currently producing at about 77,000 barrels per day and is working on a major expansion to tie in three satellite fields at an estimated cost of C$2.5 billion, but has yet to establish a timetable. Husky has earmarked C$800 million for its East Coast activities, without disclosing a breakdown, although it said an exploration well is possible.

On the Grand Banks, the semisubmersible Henry Goodrich is drilling an exploration well on a Flemish Pass license held by StatoilHydro Canada, while StatoilHydro's partner Petro-Canada has scheduled an exploration well this year as part of an East Coast budget of C$335 million.

It is not clear whether Chevron Canada will proceed with an exploration well proposed for Orphan basin, two years after completing its Great Barasway F-66 well at a cost in excess of C$200 million.

Drilling is being partly held up while Chevron looks to farm out a portion of its 50 percent working interest in two Orphan licenses.

ConocoPhillips Canada has plans for a possible US$100 million well in the Laurentian subbasin, which was initially targeted for late 2009, but timing remains uncertain pending a rig contract.

ExxonMobil Canada has on-going work at Hibernia, without disclosing how many, if any wells are planned for this year.

Royalty holiday possible

The two most significant developments in March have included indications from the Newfoundland government that it is open to a royalty holiday to kick-start its first offshore natural gas project and word from ExxonMobil that it has launched an environmental assessment of its delayed Hebron-Ben Nevis oil project.

In the 1970s and early 1980s, exploration companies chasing oil offshore Labrador struck several large, promising gas deposits — finds that were shelved because of low gas prices and inadequate technology.

Believing that both problems can be overcome, industry made a comeback in the Labrador region, with companies such as Husky, Chevron and Suncor Energy acquiring four parcels covering 2.3 million acres last year for total work bids of C$186.4 million.

Interest in gas development has been boosted by word from Newfoundland Natural Resources Minister Kathy Dunderdale that the government is "more than prepared" to consider a royalty holiday to get a pioneer gas project under way.

Bringing Newfoundland into commercial oil production has always been an odds-defying struggle with rising costs, spotty exploration results, the departure of major exploration companies, squabbling over royalties and the unrelenting challenge of operating in stormy, iceberg-infested waters.

She said a "number of companies" have shown interest in bringing Newfoundland gas into production, adding that risk-sharing between government and industry will prevail under a new royalty regime.

On March 13, lead partner ExxonMobil registered the Hebron project with the Canada-Newfoundland and Labrador Offshore Petroleum Board, setting in motion the regulatory process for exploiting 566 million barrels of heavy oil.

The preliminary schedule indicates the first oil is expected sometime between the second half of 2016 and late 2017. The productive life is estimated at 30 years, although future developments could extend that target.

ExxonMobil said that more than 70 wells could be drilled at Hebron's three fields, with 35-45 expected for the "base development." ●

GOVERNMENT

Palin appoints Ryan to ANGDA board

Governor Palin has appointed Pat Ryan to the board of the Alaska Natural Gas Development Authority.

Ryan, of Anchorage, was a top aide and chief of staff to Wally Hickel during his two terms as Alaska's governor and two years as U.S. Secretary of the Interior.

Ryan previously served as director of Alaska's first rural development agency, which later became the Department of Community and Regional Affairs; as deputy commissioner of the Department of Transportation & Public Facilities; and as director of the state Division of Aviation. He was a U.S. Air Force pilot in Alaska.

Ryan was appointed to a public seat on the authority, filling a vacancy left by recent appointee Nick Stepovich.

—PETROLEUM NEWS

Coastal impact assistance projects needed

Alaska's Division of Coastal and Ocean Management is soliciting projects for inclusion in the state's Coastal Impact Assistance Program plan, DCOM said March 6. Projects included in the plan qualify for funding from the Coastal Impact Assistance Program, a federal program established by the Energy Policy Act of 2005 and administered by the U.S. Minerals Management Service.

Projects included in the plan qualify for funding from the Coastal Impact Assistance Program, a federal program established by the Energy Policy Act of 2005 and administered by the U.S. Minerals Management Service.

Under the program, MMS allocates $250 million annually in each federal fiscal year 2007 to 2010 among six qualifying states: Alabama, Alaska, California, Louisiana, Mississippi and Texas.

Mainly because of the $2.7 billion Chukchi Sea lease sale that MMS held in February 2008, Alaska's fund allocation under the program will increase from about $2.5 million for 2007 and 2008 to between $40.9 million and $56.7 million in 2009 and 2010 — allocation of funds between the participating states depends on the relative amount of OCS revenue generated offshore of each state.

DCOM will hold public meetings via teleconference on March 18 and April 22 to answer questions about the call for proposals. Further information can be obtained from the division at 907-465-3177. The deadline for applications is 5 p.m. April 30.

—ALAN BAILEY

● UTILITIES

Governor's bill would unite 6 Alaska utilities

Proposal would have utilities buy wholesale power through state corporation; bill calls for plan to Legislature next January

By DAN JOLING
Associated Press Writer

The six utilities that serve most Alaskans would buy wholesale power through a new state corporation under a bill sent to the Legislature March 6 by Gov. Sarah Palin.

Palin announced a statewide energy plan in January and said a single entity is needed to plan, finance and build future power plants within Alaska's Railbelt, named for areas touched by tracks of the Alaska Railroad and covering about 65 percent of the population, to take advantage of economies of scale.

The new entity would be called the Greater Railbelt Energy and Transmission Corp.

The six Railbelt utilities are small by Lower 48 standards and together generate a peak load of 875 megawatts, less than some single coal or nuclear plants elsewhere.

Nearly half the existing Railbelt generation capability is scheduled to be retired in 15 years and Cook Inlet natural gas, which has helped keep rates low, is expected to either run low or jump in price. That means substantial investment will be needed for new plants, but energy experts say single utilities do not have the resources to build large projects that could give consumers the best rates.

AEA recommended authority

The call for a centralized power authority follows the recommendation of an $800,000 state study overseen by the Alaska Energy Authority. The Railbelt Energy Grid Authority study, released in September, studied management options and concluded that whether new power is generated by natural gas, coal or a hydroelectric project, a united entity with streamlined management and combined assets could save rate-payers $40 million annually over management by the six utilities.

The six utilities affected are Golden Valley Electric Association in Fairbanks, Matanuska Electric Association, Chugach Electric Association, Anchorage Municipal Light & Power, the City of Seward and Homer Electric Association.

The utilities worked on the development of Palin's proposal but support remains mixed.

Chugach Electric spokesman Phil Steyer said his cooperative supports the concept and the bill itself. Brian Newton, head of Golden Valley Electric Association, told the Fairbanks Daily News-Miner that he was disappointed that the bill carried more stick than carrot as incentive for utilities to join.

The utilities historically have enjoyed state grants to help pay for new power plants or interties but state officials have said that support is less likely in the future unless the utilities work together.

Power at cost

Palin's bill would set up the corporation to operate on a nonprofit basis. Its stated purpose would be to provide adequate and reliable wholesale power to the utilities at the lowest cost, procure a fuel supply and ensure adequate transmission.

The corporation's board would be made up of two representatives from each utility and one member appointed by the governor.

The bill calls for the corporation to adopt a plan for selecting new generation and transmission projects.

It also calls for the corporation, with the Alaska Energy Authority, to develop a transition and finance plan before Jan. 19 — no small task given that the utilities operate under a variety of state and federal rules, depending on their makeup. They all have long-term obligations for purchasing fuel and paying off debt.

Palin's energy adviser, Joe Balash, said the plan envisions the corporation acquiring the power plants of the utilities unless they're near the end of their useful lives or covenants on debts would make them more expensive to acquire than what they're worth. In any case, he said, power they generate would be sold to the new corporation to be dispatched most economically as part of an overall portfolio.

Utilities would have until July 2010 to decide whether to be part of the corporation or continue to operate independently. ●

● OUR ARCTIC NEIGHBORS

Norway's far north looking promising

Report ranks areas, all currently closed to development, pressuring government to support industry in data gathering, job creation

By SARAH HURST
For Petroleum News

A new report by Norwegian petroleum industry association KonKraft ranks the most interesting northern exploration areas on the Norwegian continental shelf, as well as highlighting the potential jobs that would be created in the region as a result of increased activity. The report also described the kinds of technology that could be used to develop fields in the far north.

"Forecasts indicate that Norwegian petroleum production will fall markedly over the next decade," said Per Terje Vold, chief executive of the Norwegian Oil Industry Association. "Access to new and attractive exploration acreage would slow this decline, sustain government revenues to the benefit of the community, keep 250,000 people in work and open opportunities for 1,000 to 2,000 new jobs."

According to the report, the oil and gas companies have ranked the most promising northern areas as the Nordland VI area, the Nordland VII area, and the Troms II area. These are located progressively farther north, although within the Nordland VII area the central-northern part is considered more promising than the southern part.

"The basic assumption in Nordland VI is that one large oil discovery will be made, together with a medium-sized oil and gas find and some smaller strikes which could eventually tied back to the first two," the report said. Within Nordland VI, a discovery in the Ribban basin would lie 100 kilometers (62 miles) from the mainland and about 100 kilometers off the main Lofoten islands. One made on the Utrost Ridge would be 200 kilometers (124 miles) from the mainland and about 100 kilometers off Lofoten, the report added. The Lofoten area is home to fisheries where possible oil and gas development is considered extremely controversial.

The report's assumption for Nordland VII is that the interesting areas lie 60 kilometers (37 miles) from Lofoten and 20-40 kilometers (12-24 miles) off the island of Andoya. There could be a large gas discovery as well as a medium-sized oil and gas find in these areas, according to the report. In Troms II, 20-40 kilometers off the island of Senja, the report assumes that a medium-sized oil field could be discovered.

A large oil discovery is defined by the report as 600-700 million barrels of oil equivalent — on a par with Norne. A large gas discovery is defined as 100 billion standard cubic meters (3,530 billion cubic feet) — on a par with Frigg. A medium-sized oil or gas discovery is defined as 200-300 million barrels of oil equivalent — on a par with Njord or Mikkel.

Subsea development with well streams piped to land is seen as a good option for many of these areas, the report said.

"A solution of this kind could create substantial local spinoffs, including jobs. Subsea installations are also overtrawlable and thereby have no impact on fishing," it continued. The cost of different solutions has not been analyzed in the report. The most important factors for comparison with an offshore solution are field size and distance to land, the report said.

"Gas can be piped today over longer distances than oil. …Technology development will concentrate on ensuring that crude from Nordland VI could be landed," the report said. "A subsea solution with well stream transport to shore would require a relatively substantial resource base to be profitable. … For smaller fields, offshore solutions are likely to be the most appropriate. Technological progress up to the time of a possible development could mature a landfall option."

A number of areas on the Norwegian continental shelf are immature as possible petroleum provinces, with very little data gathered, according to the report. That applies to the area of overlapping claims between Norway and Russia in the Barents Sea, the northern Barents Sea, Svalbard and Jan Mayen.

"Securing information about the potential for oil and gas exploration in these areas will be very important over the next few years in order to improve the basis for analysis and decision-making by government and industry," the report said. The report also recommended that the government establish environmental standards for operating in these waters at an early stage. ●

StatoilHydro finds more gas in Norwegian Sea

StatoilHydro has found gas in the Asterix prospect, which lies in the Norwegian Sea at a depth of 4,461 feet, 214 miles west of the town of Sandnessjoen, the company said in a release March 16. Preliminary estimates put the proven recoverable volume at about 565 billion cubic feet (100 million barrels of oil equivalent) in Upper Cretaceous reservoir rocks. No formation test was carried out, but extensive data gathering and coring took place in the reservoir.

"This represents one of the bigger discoveries off Norway in recent years, and we're very pleased with the result," said Tove Stuhr Sjoblom, StatoilHydro's head of Norwegian exploration.

OUR ARCTIC NEIGHBORS

New gas play proved

"The well has proved a new play and found gas in rocks with good reservoir properties," said Frode Fasteland, StatoilHydro's exploration manager for the Norwegian Sea.

With its location 50 miles west of the 1,341 billion-cubic-feet Luva natural gas field, discovered in 1997, Aterix provides exciting opportunities for further exploration in the area, Fasteland said.

"Asterix will be considered for development together with Luva and the other nearby discoveries of Haklang and Snefrid South," she said. "That could help to lay the basis for a deepwater gas infrastructure in the Norwegian Sea."

In addition to StatoilHydro as operator, with 70 percent, licensees in production license 327B are Petoro with 20 percent and Norske Shell with 10 percent. The exploration well where the gas was found is the first in production license 327B, which was awarded as supplementary acreage in the 18th licensing round in 2007. The well has now been permanently plugged and abandoned.

Drilling was done by the rig Transocean Leader, which will now be redeployed to the North Sea to drill a delineation well on the Fulla structure.

—SARAH HURST

● NATURAL GAS

Teasing natural gas from Cook Inlet

Difficult seismic, more subtle plays and discontinuous sands all add to the challenges in finding and producing gas from the basin

By ALAN BAILEY

Petroleum News

Over the years Alaska's Cook Inlet basin has proved to be a prolific source of gas.

But with oil and gas fields found decades ago becoming depleted and the easy finds on major geologic structures all discovered, people now need to seek new gas in more elusive prospects, tucked away in the basin's challenging geology, as well as by continued development of existing fields, Julie Houle, resource evaluation section chief in Alaska's Division of Oil and Gas told the House Special Committee on Energy March 17.

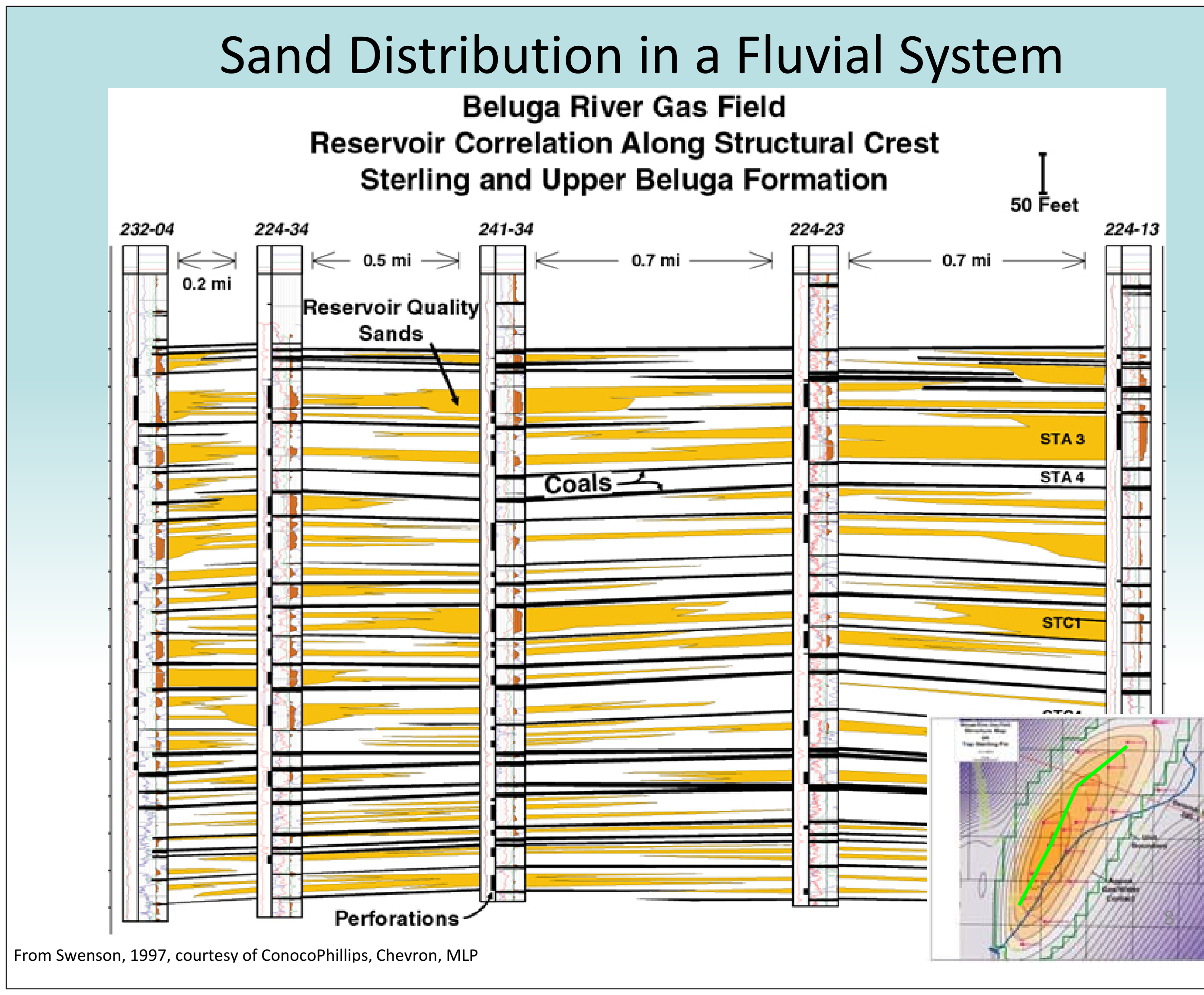
"As exploration geologists we think there is more gas to be found in Cook Inlet, and we think it's going to be found both in existing fields and in new exploration play types," Houle said.

Those easy finds made years ago on the big structures resulted from 2-D seismic surveys — the division would like to see companies now shooting some 3-D seismic to pursue new exploration concepts in the basin, she said.

The division thinks that there is new gas to be found in what are known as stratigraphic traps, situations where the way in which the rock strata were laid down has resulted in a reservoir rock becoming juxtaposed with an impervious seal rock.

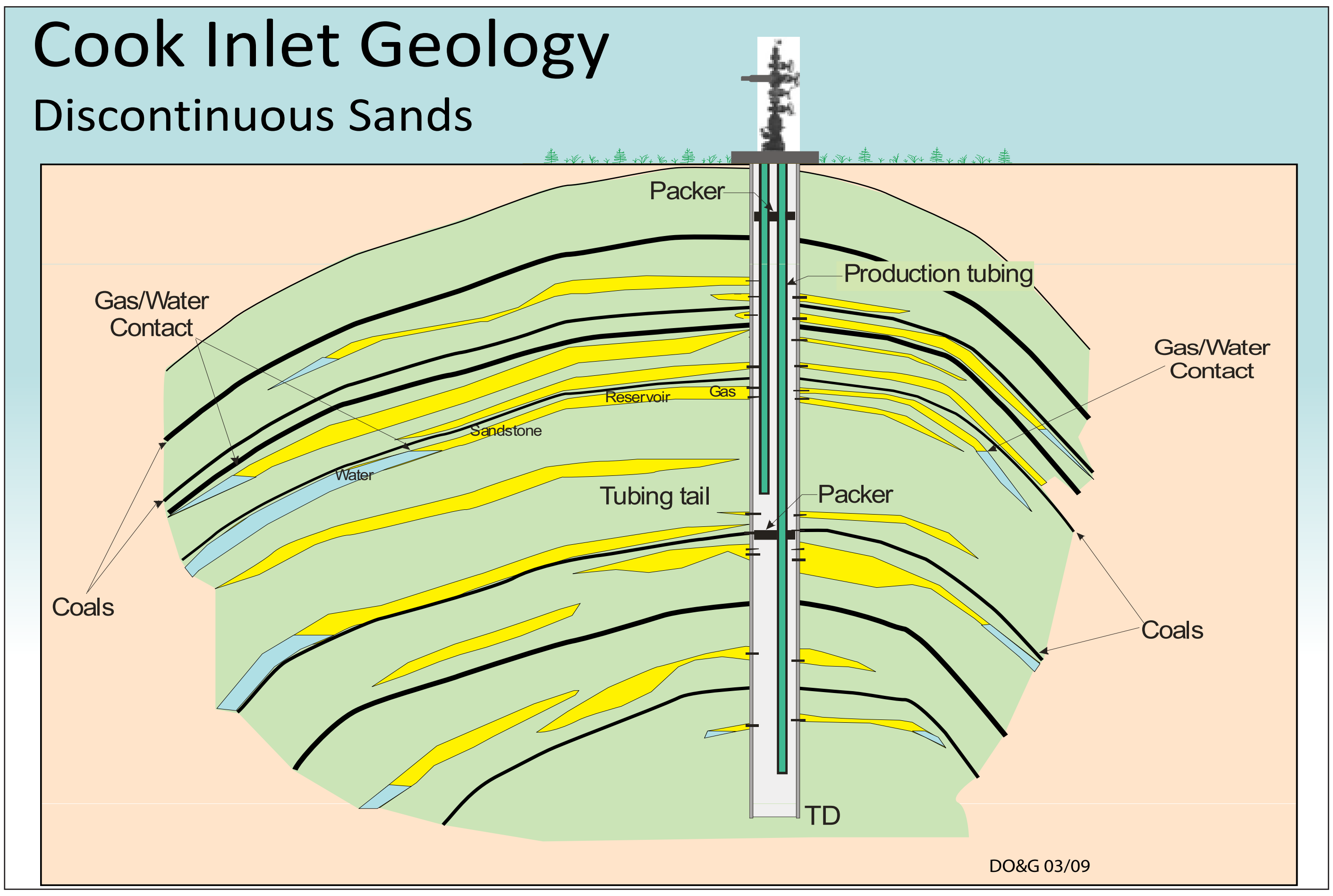
"It will take someone in the Cook Inlet

see TEASING GAS *page 12*



ALASKA DEPARTMENT OF NATURAL RESOURCES DIVISION OF OIL AND GAS

A section through the Beluga River gas field on the west side of Alaska's Cook Inlet. Coal seams can wreak havoc with seismic data, while the thin, discontinuous reservoir sands present major challenges in field delineation and development.



ALASKA DEPARTMENT OF NATURAL RESOURCES DIVISION OF OIL AND GAS

A schematic cross-section of a typical structure in a Cook Inlet gas field. A single well is unlikely to penetrate all of the discontinuous gas sands in the field, while gas production needs to be tapped from multiple, thin sand bodies.

continued from page 10

TEASING GAS

with money and a lot of fortitude and courage to keep going, looking for these subtle stratigraphic traps," Houle said.

Dome-shaped structures, to the side of main folds in the rock strata, are other possible new exploration targets, she said.

Difficult seismic

But seismic data from the Cook Inlet basin are notoriously difficult to interpret. The river-lain sands that form gas reservoirs in the basin tend to be too thin to resolve in the images depicted in seismic cross sections of the subsurface, while the coal seams that pervade many of the rock sequences also tend to distort those seismic images.

The reservoir sands also tend to be discontinuous, forming thin lenses rather than continuous strata. Consequently, when drilling through a prospective structure an individual sand that may contain viable pay can easily be missed. And a gas discovery in one well requires a series of delineation wells to locate all of the various sand bodies that might produce gas.

At the same time, testing of the gas pressure may be necessary to determine whether a reservoir sand at one place connects with a similar reservoir sand nearby.

"All sands don't hit all wells and you really need close control in order to figure out what is in communication," Houle said. "… You could go back in, in a field, and drill in between wells and you could actually get more gas."

In addition, a sand that has been producing gas for some time tends to fill with water if the well that taps that sand is shut-in.

"That's why once you drill a well in Cook Inlet you want to keep it producing," Houle said. ●

● SAFETY & ENVIRONMENT

Prince William Sound 20 years later

In the years since Exxon Valdez oil spill prevention and response capabilities have increased vastly and become more sophisticated

By ALAN BAILEY
Petroleum News

The grounding of the tanker Exxon Valdez on March 24, 1989, and the subsequent unleashing of nearly 11 million gallons of crude oil into the pristine waters of Alaska's Prince William Sound has gone down in history as one of the more noteworthy manmade environmental disasters.

But in the aftermath of the accident, a recognition of complacency over the possibility of an oil spill involving the Valdez terminal or its tanker traffic, coupled with a realization that contingency arrangements for a spill had been woefully inadequate, triggered new federal and state legislation, heightened regulatory oversight and caused a complete rethink of oil spill prevention and response in the region.

The tanker had run aground on Bligh Reef, at the eastern end of the sound, after straying from the tanker route that runs between Valdez Narrows, at the mouth of Port Valdez, to Hinchinbrook Entrance, the broad channel that passes from Prince William Sound into the Gulf of Alaska. At the Valdez Marine Terminal in Port Valdez tankers fill up with North Slope crude oil from the trans-Alaska oil pipeline. The tankers transit the eastern end of the sound before heading south through the gulf to deliver their cargos to the U.S. West Coast.

But how have lessons learned from the Exxon Valdez disaster been applied to this busy tanker route?

On Feb. 2 at the Alaska Forum on the Environment Michael Levshakov, public relations coordinator for Alyeska Pipeline Service Co., the operator of the trans-Alaska oil pipeline and Valdez Marine Terminal, described how oil spill prevention and response in Valdez and Prince William Sound have been bolstered over the past 20 years.

SERVS

For a visitor to Valdez harbor, perhaps one of the more visible consequences of change since 1989 is the large, block-shaped building that serves as headquarters of the Ship Escort/Response Vessel System, an organization formed shortly after the Exxon Valdez disaster as part of APSC. SERVS, as the organization is generally known, provides tug escort services for tankers plying the route to and from Valdez; SERVS also provides oil spill response services for the oil terminal and for the shippers that operate the tankers.

A key priority for SERVS and other organizations has been prevention of another tanker accident, Levshakov said.

In 1989 APSC had three escort vessels and one of these vessels would escort a tanker as it plied the Valdez Port and the narrows at the port entrance, with the escort service ending off Rocky Point, a promontory a few miles southwest of the narrows, Levshakov said.

Nowadays SERVS operates an escort fleet consisting of five state-of-the-art tugs — two 10,192-horsepower enhanced tractor tugs, and three 10,200-horsepower prevention-response tugs — all of which have drive systems that enable great maneuverability.

Two tugs escort each tanker, with one tug tethered to the tanker's stern, ready to drag the tanker out of harm's way should some emergency arise. And the tethered tug accompanies the tanker all the way out

see SERVS page 14

COURTESY ALYESKA PIPELINE SERVICE CO.

Two Crowley tugs escort an oil tanker through Prince William Sound. One of the tugs is tethered to the tanker for the whole passage between the Valdez Marine Terminal and the entrance to the Gulf of Alaska.

continued from page 13

SERVS

to Hinchinbrook Entrance, rather than just to Rocky Point. In addition, a professional pilot on the tanker's bridge helps the tanker crew negotiate the route between Valdez and the Bligh Reef area.

Coast guard

The U.S. Coast Guard has also beefed up its operations, Levshakov said.

In 1989 a single USCG watch person monitored tanker traffic using a radar system that scanned Port Valdez, the Valdez Narrows and the Valdez Arm of Prince William Sound, as far as Rocky Point. Tracking vessel positions and movements outside of radar coverage required ship-to-shore radio communications.

"The rest of Prince William Sound relied upon radio check-ins and plotting, with one watch keeping track of all that," Levshakov said.

Since those days, the coast guard has upped the watch to two people, while also reducing the number of hours that each person remains on duty, Captain Mark Hamilton, USCG captain of the port for western Alaska, told the forum. And information available to the coast guard has vastly improved, with data from an automatic ship identification system overlaid on radar plots, and with ice coverage radar providing a picture of ice drifting out from the nearby Columbia Glacier.

COURTESY ALYESKA PIPELINE SERVICE CO.

The 10,200-horsepower Crowley prevention-response tug Attentive is one of five state-of-the-art, ocean-class tugs used to escort tankers through Prince William Sound, on their way to and from the Valdez Marine Terminal.

There is now a system of marine speed limits in the region. In addition, the coast guard maintains radio contact with tankers and will alert a tanker crew if the tanker starts to stray off course, Hamilton said.

"There's also a (USCG) chief of the vessel tracking system, whose primary duty is to ensure that the two watch standers are able to carry out their duties without being distracted," Levshakov said.

A SERVS control room also maintains contact with vessels in Prince William Sound, while using the same types of automatic vessel identification system and ice coverage radar as the coast guard to monitor the situation out on the water, Levshakov said.

Double-hulled tankers

The Oil Pollution Act of 1990, a piece of federal legislation enacted as a direct consequence of the Exxon Valdez disaster, mandated the phasing in of double-hulled tankers, to replace the single-hulled design of vessels such as the Exxon Valdez. By preventing leakage of oil if just the outer hull is breached, the introduction of double-hulled designs substantially reduces the oil spill risk if a tanker runs aground or hits a rock.

Of the 17 tankers that operate in and out of Valdez, 16 now have either double hulls or double bottoms, Levshakov said. The last single-hulled tanker is slated to leave the system in early 2010.

Nine of the tankers also have duplicate rudder and propulsion systems, to guard against an equipment failure, Levshakov said.

And other precautions relating to tanker operation include strict alcohol screening for captains and officers, as well as operational restrictions relating to weather and sea conditions.

Spill response

But what if the worst were to happen and oil is spilled?

The escort tugs carry skimmers and boom, ready to swing into action if necessary. However, the equipment on the tugs represents just a tiny portion of a vast inventory of spill response equipment now staged in Valdez and at various sites across Prince William Sound.

SERVS now has nearly 50 miles of various types of boom, 108 skimmers providing a total of 59,000 barrels per hour of oil recovery capacity and nine oil recovery barges with a total of 900,000 barrels of on-water storage capacity, Levshakov said. Tugs and response barges provide mobile platforms for deploying equipment to a response site.

That all compares with the one deck barge, three skimmers, 2.5 miles of boom and about 5,000 barrels of on-water storage available out of Valdez in 1989 when the Exxon Valdez hit Bligh Reef, Levshakov said.

And nowadays, in addition to storing response equipment in Valdez, SERVS stages equipment at five salmon hatcheries and five remotely located response sites scattered across the Prince William Sound region. This remote staging of equipment would save time in moving boom, skimmers and other pieces of kit to sensitive sites after an oil spill incident. And numerous sites with high environmental sensitivity have pre-specified oil spill response plans.

Fishing vessel program

Since 1989 SERVS has established a fishing vessel program that has enrolled more than 350 vessels under contract, to assist with operations such as on-water oil recovery, were an oil spill to occur. More than 200 of the contracted fishing vessels are based in Prince William Sound. SERVS runs fishing vessel training twice a year.

COURTESY ALYESKA PIPELINE SERVICE CO.

Fishing vessels being trained in the use of boom as part of the Alyeska SERVS fishing vessel program. SERVS has more than 350 vessels under contract, to assist with an on-water response to an oil spill.

In addition to the SERVS use of local fishing vessels, the formation of the Prince William Sound Regional Citizens' Advisory Council has ensured local community involvement in decisions and arrangement for oil spill prevention and response.

And the oil spill response training and organizational arrangements have also been vastly improved since 1989. The use of the Incident Command System — a system of standard crisis response organizational protocols and procedures — by all organizations potentially involved in mounting a Valdez or Prince William Sound response, including the oil shippers, USCG and the State of Alaska, ensures a common understanding of roles, responsibilities and procedures.

And these various organizations participate in major annual oil spill drills, typically involving hundreds of people. SERVS also periodically tests the deployment of equipment at remote sites such as salmon hatcheries, Levshakov said.

But Hamilton emphasized that the oil spill prevention and response capabilities that now exist, 20 years after the Exxon Valdez, result from a group effort, involving multiple organizations and with citizen involvement.

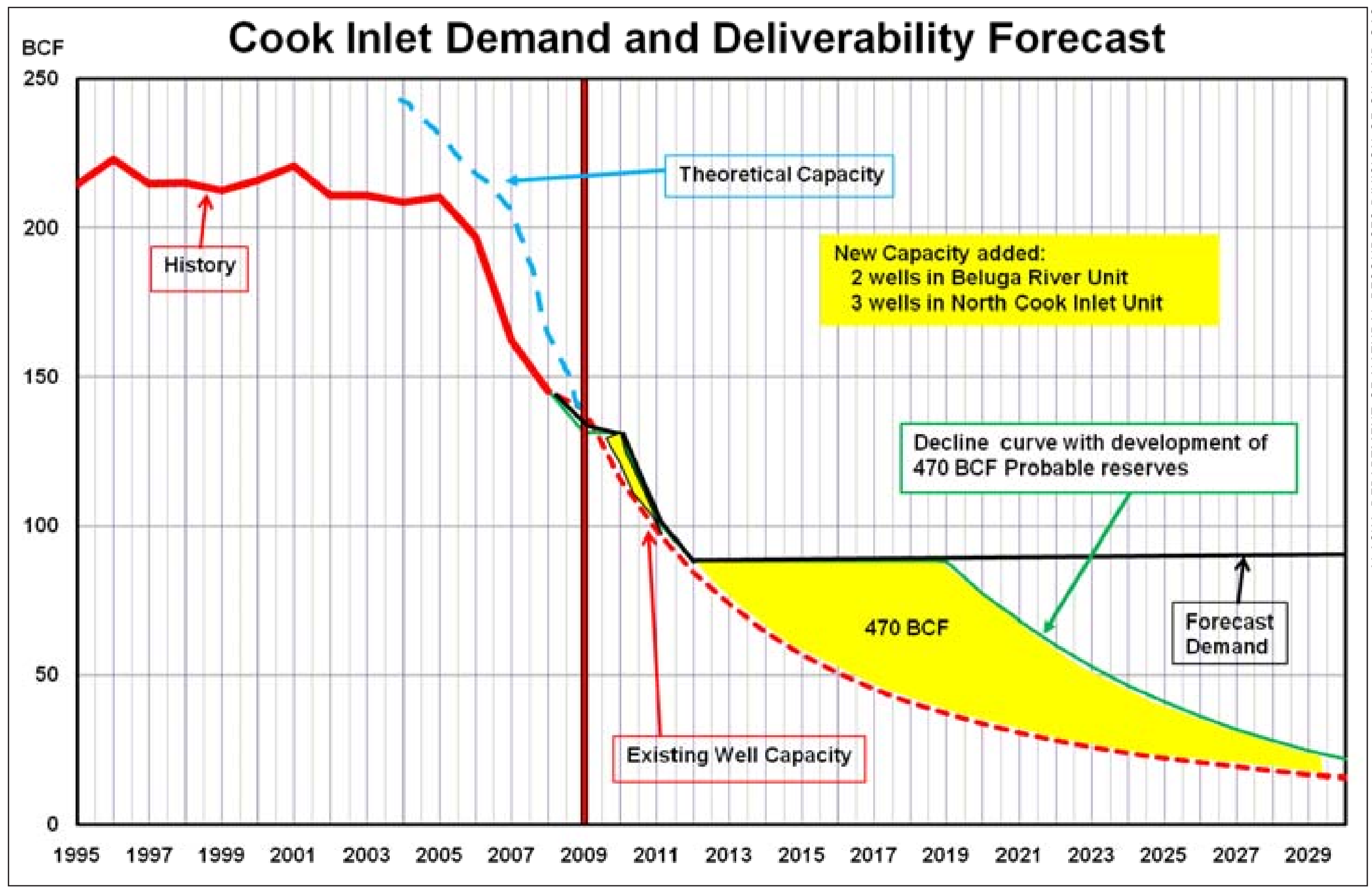
The involvement of the local communities is "incredibly important," he said. ●

● NATURAL GAS

More perspectives on the CI gas market

Banks says 470 bcf could be developed in existing fields; CEA wants resource management plan; ML&P pushes for state intervention

By **ALAN BAILEY**
Petroleum News



In the past the theoretical gas production capacity of Cook Inlet oil and gas fields has significantly exceeded annual production. However, declining capacity will result in a shortfall of gas from 2011 onward, unless new gas wells are drilled. Alaska's Division of Oil and Gas thinks that new drilling in existing fields could deliver an additional 470 billion cubic feet, delaying the gas shortfall to 2019, if the Kenai Peninsula LNG plant closes in 2011.

The Cook Inlet gas cliff — the apocalyptic graph that shows a precipitous decline in gas production over the next few years — has the capability of making even the hardiest resident of Southcentral Alaska shudder, as he or she sits in the warmth of a gas-heated home on a 20-below January evening.

But what does this graph really mean? And what steps can be taken to ensure that Alaskans who depend on natural gas are not left "out in the cold?"

KEVIN BANKS

On March 13 Kevin Banks, director of Alaska's Division of Oil and Gas, told the House Special Committee on Energy that the data on that graph assume that future gas would only come from continued production from existing wells in existing fields.

"It's based on an assumption that no further investments are made in the inlet," Banks said.

In addition, the graph depicts average annual production, rather than the theoretical maximum production capacity of the Cook Inlet gas fields.

Look at capacity

As an alternative perspective, Banks presented a graphic in which that theoretical capacity is overlaid onto the familiar gas cliff, together with a plot of historic and projected natural gas demand in Southcentral Alaska. The graph shows that in the past the theoretical capacity has significantly exceeded average production while, in the future, capacity comes into line with the production cliff.

Total gas usage has shown a steep decline, with Agrium's Kenai Peninsula fertilizer plant closing down in 2007 and throughput in the neighboring LNG plant dropping. And, on the assumption that the export of LNG from the Kenai Peninsula would cease when the current export license expires in 2011, the annual gas demand after that date would level off somewhat below 100 billion cubic feet, the quantity primarily required to supply local gas and power utilities.

But the production capacity of the current gas wells would also drop below that projected demand level at about the time that LNG exports cease, according to the division data.

470 bcf

However, the division thinks that there are 470 billion cubic feet of additional gas that the gas producers could access in existing fields through the drilling of new wells.

"This is gas in those discontinuous (Cook Inlet) sands that has not been reached by the existing wells," Banks said.

And spreading 470 billion cubic feet of gas across the multiyear gap between projected demand and projected production from existing wells extends the shortfall in Cook Inlet gas production out to 2019. Any further supplies would then have to come from new gas exploration.

But the producers need a market outlet for their new gas if they are to drill for that extra 470 billion cubic feet.

"A producer will not drill a well until it knows that it has a place to sell (the gas)," Banks said. "What we've seen in the past … is that a producer will enter into a supply contract with a customer and meet the supply requirements for that customer by additional drilling."

And if the federal government allows LNG exports to continue beyond 2011, some of that extra gas would likely head for the LNG terminal. So, in the negotiations for the next LNG export license renewal, the state needs to ensure that the producers commit to developing these new reserves "and then some," Banks said.

Extreme swings

Any consideration of the Cook Inlet gas market also needs to take into account the extreme swings in Southcentral Alaska utility gas demand between summer and winter

see **GAS MARKET** *page 16*

FINANCE & ECONOMY

Saudis say oil needs to be at $60-$75

Saudi Arabia's oil minister said March 16 that petroleum-producing countries need a price of at least $60 a barrel to bring more energy resources on the market.

"If we want all hydrocarbon resources developed worldwide, 40 dollars is not enough," Ali al-Naimi told reporters in Geneva, where he was attending an energy conference.

Crude oil returns are key, he said, because they can allow companies and countries to invest in new and potentially valuable fuel source such as ethanol, tar sands and heavy oils. To develop these industries, the oil price will have to rise to a range between $60 and $75 a barrel, al-Naimi said.

Crude oil prices fell near $44 a barrel in Asia March 16 after OPEC decided not to cut production levels at a Vienna meeting over the weekend. They were as high as $147 a barrel only eight months ago.

Al-Naimi said fossil fuels will continue to play a vital role in satisfying the world's energy demands, supplying as much as 80 percent of the world's fuel "for at least the next few decades."

But he said oil-rich nations should invest in making production more efficient and environmentally sustainable.

"There is no excuse to pin our hopes only on alternatives, which today are just supplemental energies, when it comes to optimizing our energy future," he said.

—THE ASSOCIATED PRESS

LAND & LEASING

Land transfer appeal upheld by court

On March 13 the Alaska Supreme Court upheld an appeal against the transfer of 250,000 acres of state land to the University of Alaska's endowment trust. The Southeast Alaska Conservation Council and the Tongass Conservation Society had appealed the land transfer on the grounds that the transfer violates the dedicated funds clause of the Alaska constitution, a position that the court has now agreed with.

Legislation enabling the land to be conveyed to the university was passed in 2000 and 2005, with the intent of providing an additional source of income for the university. The Alaska Department of Natural Resources and the university have since been carrying out the land transfer, a process that the court decision will require to be reversed.

Tom Irwin, commissioner of DNR, expressed his frustration with the situation and noted that "the lawsuit was filed well after the Legislature acted and after the land transfers had begun, and the department and university spent substantial staff and consultant resources on land transfers that must now be undone."

Some of the land earmarked for transfer is in the Nenana basin, where Rampart Energy Co, in partnership with Doyon Ltd., Arctic Slope Regional Corp. and Usibelli Energy, is exploring for natural gas and plans to drill a well this summer.

James Mery, senior vice president for lands and natural Resources for Doyon Ltd, told Petroleum News March 18 that, although the land that had been earmarked for the university is close to where the Nenana basin gas exploration is taking place, the issues relating to the land transfer is unlikely to impact the exploration program. The exploration well planned for this summer will be drilled in Alaska Mental Health Trust land, he said.

"Our exploration group has a very good working relationship with the Division of Oil and Gas," Mery said. "We were however looking forward to working with UA to assist them in fulfilling their objective to generate needed revenues for the university system."

—ALAN BAILEY

Historic Deliverability

	2/3/1999	1/9/2007	1/3/2009
Average Temperature	-19° F	-10° F	-11° F
On Enstar System	272	292	314
CEA Beluga	83	83	60
CEA/HEA Nikiski	14	12	12
LNG	224	150	40
Agrium	157	0	0
Other Industrials	13	6	14
Total Deliverability	763	543	440
less Storage Volumes	0	~43	~60
Well Supply	763	500	380

ALASKA DEPARTMENT OF NATURAL RESOURCES DIVISION OF OIL AND GAS

Total Cook Inlet gas delivered during peak winter demand has declined dramatically since 1999. This decline is almost entirely attributable to the closure of Agrium's Kenai Peninsula fertilizer plant and the curtailment of production in the neighboring LNG plant. Gas delivered through Enstar Natural Gas Co.'s system has actually grown, due presumably to an increase in the gas utility's customer base.

continued from page 15

GAS MARKET

— rather like a day-to-day cash flow problem when operating an otherwise viable business, a gas deliverability shortfall during peak winter demand will cause extreme difficulty, even if there is enough gas to meet total demand on an annual basis.

"In the past there was sufficient capacity in all of the fields to simply produce more gas from the existing wells (in the winter)," Banks said. "Now it has become more of a delicate balancing act."

Utilities that anticipate extreme "needle peaking" demand can cushion that demand by increasing gas pipeline pressure, to step up the line pack. But it is mainly the Cook Inlet producers who accommodate demand swings by using producer-operated underground gas storage, drilling more wells into existing gas fields and by diverting gas intended for the LNG plant, Banks said.

The division would like to see new gas storage facilities available to any business that needs storage, rather than just to a producer that operates the facility.

"Those kinds of market mechanisms are common in the Lower 48 and I think there is a wonderful opportunity to have those sorts of things working here, so that the market can respond as it should," Banks said.

Bradley Evans, CEO of Chugach Electric Association, the main Anchorage electric utility, expressed frustration at the lack of information transparency in the Cook Inlet gas market. Chugach generates 90 percent of its power from natural gas and has been trying to negotiate new gas supply contracts with the Cook Inlet producers. And although Chugach wants to move toward a high degree of renewable energy usage, thus lowering the gas demand for power generation, the continued use of natural gas is an essential stepping stone to that renewable future, Evans said.

"The Cook Inlet (gas) resource is vitally important to us," he said.

Chugach wants to see the development of a Cook Inlet resource management plan and the formation of a Cook Inlet public gas authority, which would represent consumers and would probably include the gas and electric utilities as members.

"There are organizations out there that combine the interests of consumers — there's a large gas authority in the southern United States," Evans said.

The resource management plan would be designed to address fuel supply security and information transparency, and it would lead to well-timed investments and rational management decisions. The plan would dovetail with the state's Railbelt integrated resource plan.

"We have some (gas) storage options we're working on," Evans said. "The timing of those investments is critical."

Needs to be supercharged

James Posey, general manager of Anchorage electric utility Municipal Light and Power, supported the resource management plan concept but called for much faster action.

"The whole process that we're going about, looking at the Cook Inlet, needs to be turbocharged," Posey said. "… We're going to have some real problems if we don't find new gas." Posey said that he is really worried about gas supplies between 2014 and 2020 and that gas supply problems need to be resolved within three years.

"We need to put the state in front of that engine to make sure that we look for another trillion cubic feet of gas, to get us to where a bullet line or a line to the North Slope or LNG imports can grant us some security beyond 2020," Posey said, suggesting initiatives such as persuading the federal government to open more of its land for exploration, or making sure that a jack-up rig comes to the Cook Inlet for offshore exploration drilling.

The dream of a North Slope gas pipeline has been floating around since 1975.

"We're still waiting on it," Posey said. "So it is important for the state to play a role in the Cook Inlet exploration. … Whatever that role is … it is going to require some allocation of resources." ●

● LAND & LEASING

State and Escopeta near deal on Kitchen

Details limited, but Banks tells House committee division is awaiting a final plan of exploration for the offshore Cook Inlet unit

By ERIC LIDJI
Petroleum News

The state is near an agreement with an independent oil company on a proposal to explore a bundle of offshore prospects in the Cook Inlet, according to a top oil and gas official.

The Division of Oil and Gas is waiting for Houston-based Escopeta Oil to provide a final plan for exploring the proposed Kitchen Lights unit, according to Director Kevin Banks.


KEVIN BANKS

Kitchen Lights would cover the Kitchen and Corsair units and the Northern Lights prospects in the waters of upper Cook Inlet, south of the village of Tyonek.

Testifying before the House Special Committee on Energy on March 17, Banks said Escopeta committed to give the state "a plan of exploration for the area of all of these leases with real live drilling commitments," and while the state doesn't yet have the plan in hand, "on a couple of occasions (Escopeta President) Danny Davis has made the commitment that if he fails to meet those due dates, he will relinquish the leases."

Escopeta picked up the original Kitchen unit leases years ago, but only recently acquired additional acreage in the area through a series of deals made earlier this year, farming-in Corsair from California-based independent Pacific Energy Resources Ltd. and Northern Lights from Texas-based independents Renaissance Alaska and Rutter and Wilbanks.

Following the acquisition, Escopeta asked the state to expand the boundaries of the Kitchen unit to cover all of the leases and change the name of the unit to Kitchen Lights.

Unit would be largest in inlet

At 83,394 acres, the expanded unit would be the largest in Cook Inlet.

Banks placed all of those leases, about 30 all together, in default at the end of last year because the companies failed to meet work commitments to the satisfaction of the state.

But at the time, the state also offered to extend the life of the leases if the companies joined their holdings together into one unit and promised to drill a well by this summer.

Instead, Escopeta decided to go it alone, acquiring leases held by the other companies.

The state originally gave the companies until March 1 to agree to the deal.

Banks said the Escopeta proposal met that deadline. The state is now awaiting a finalized plan of exploration from the company before going public with the proposal, he said.

In a draft plan of exploration, Escopeta proposed to have a rig headed to Alaska by June 30, 2010, to drill a well in the expanded unit by the end of that year. Escopeta also gave a timeline for drilling additional wells across the expanded unit each year through 2013.

Those dates are beyond the original deadlines proposed by the state last December.

The state, however, may be amenable to offering an extension. The December proposal included a deadline for companies to have a specialty rig headed to Alaska by March 15.

The state hopes to reach a final agreement before the end of March. ●

Contact Eric Lidji at 907-522-9469 or elidji@petroleumnews.com

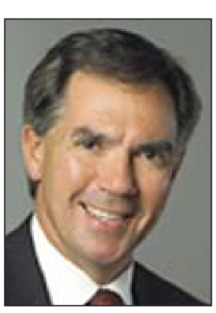
● NATURAL GAS

Mackenzie Gas Project faces legal threat

Canadian cabinet minister believes Joint Review Panel can finish scheduled work by December, but discloses he is seeking 'legal advice'

By GARY PARK
For Petroleum News

Jim Prentice has ranged from cheerful optimist to stern taskmaster in almost three years as the Canadian government cabinet minister assigned to steer the Mackenzie Gas Project through the approval jungle.


JIM PRENTICE

Less than a month after suggesting the project has "never been closer," he was back on the warpath March 16, telling a Calgary business audience he has "sought legal advice" on how to force the hand of a Joint Review Panel, charged with overseeing the environmental and socio-economic impacts of the MGP.

But he declined to say what legal options might be pursued.

However, Prentice confirmed that the JRP's work has now cost more than C$19 million, compared to the original budget of C$6.8 million set in 2004.

The billings have now reached C$750,000, at the standard federal rate of C$650 a day, for panel chairman Robert Hornal, who told the Globe and Mail he does not believe he is overpaid or underpaid.

Hornal conceded the panel has "taken much longer than we anticipated doing the job."

Having earlier voiced his displeasure at the plodding progress of the JRP, Prentice argued the panel's mandate was determined by the Liberal government, before it was defeated in a January 2006 election.

Original projection 24 months

The normally mild-mannered Prentice revealed some of his feelings, when he said, "Originally, as I recall, the JRP was supposed to take 24 months. It's now into its fifth year."

He told reporters that he has tried through the Canadian Environmental Assessment Agency to remain updated on the spending, the regulatory work that is ongoing and "the best information we have from an arm's length distance about the progress they're making towards the December report."

At the same time he dangled the threat of legal action, Prentice once more said the project, "which is something our country has worked on for 40 years, has never been closer. The process, while it has been slow, is at this point within months of conclusion."

> *"Originally, as I recall, the JRP was supposed to take 24 months. It's now into its fifth year."*
> **—Canadian Environment Minister Jim Prentice**

Feelings boiled over in December, when the JRP indicated it would need another year to complete its recommendations to Canada's National Energy Board.

Prentice, who said in January he expected the JRP to deliver its report no later than May, said March 16 there is no indication that the panel will fail to meet its December target date.

That left unanswered questions about why he felt the need at this point to raise the legal option.

However, he did say that "most, if not all, of the aboriginal issues relating to the project will be resolved (by December);we'll be in a position to deal with the environmental issues and we will be left simply with questions about the fiscal framework that will apply to the pipeline."

Assessment procedures changed

Prentice also told his Calgary audience the Canadian government has changed the environmental assessment procedures for infrastructure projects funded through a C$12 billion stimulus program.

He said projects such as roads and bridges will no longer have to face separate municipal, provincial and federal reviews to ensure "rapid deployment" of infrastructure investments over the next two years.

The new rules "will focus on our resources" by cutting down on "unnecessary" assessments for projects the government knows will not have any environmental consequences.

An estimated 2,000 projects could be exempted, eliminating 90 percent of reviews, government sources have said.

But Prentice has given no hint that he plans to extend the changes to megaprojects such as the MGP. ●

LAND & LEASING

Salazar opens door (slightly) on ANWR

Says directional drilling might resolve issue of surface disturbance, but wants to see more information about the technology

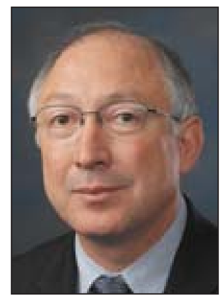
PETROLEUM NEWS

Interior Secretary Ken Salazar on March 16 said he would consider tapping oil from the coastal plain of the Arctic National Wildlife Refuge if it can be done from outside the boundaries of the North Slope refuge, leaving animals and other wildlife undisturbed.

But Salazar emphasized the Obama administration stands firm that ANWR "is a very special place" that must be protected and that he is not yet convinced directional drilling would meet that test.

Sen. Lisa Murkowski, R-Alaska, recently introduced legislation that would allow oil companies to access oil beneath the Arctic refuge's coastal plain, also known as Area 1002, through directional drilling from platforms outside the refuge itself.

"I think some in the administration are looking at me and saying, 'You must be crazy, Lisa. We've always opposed ANWR and you're coming back with an ANWR proposal,'" Murkowski told reporters at the Platt's Energy Podium on March 16. "But my response is, 'Hey. This is different. You've always said you object to the surface disruption. … Well, if we're not on the surface — if we're not out there, if you can't see us — tell me what your objection is.'"


KEN SALAZAR

Salazar remains uncertain about the available technology.

"The question of whether or not you can do directional drilling without impairing the ecological values of ANWR is an open question. Most of what I've seen up to this point is it would not be possible to do that," Salazar said in a conference call with reporters.

Salazar said directional drilling is "something that can be discussed" because of recent advancements in the technology, but testifying on March 17 before the Senate Energy and Natural Resources Committee, of which Murkowski is the ranking member, Salazar said, "Our position as an administration has not changed at all with respect to ANWR."

Sen. John McCain, R-Arizona, who has previously been opposed to drilling in ANWR, said if the technology isn't available, the proposal is a non-starter, but if technology exists and can be used to tap resources without disturbing the refuge, "we ought to pursue it."

Salazar is scheduled to come to Alaska in April to discuss energy-related issues.

A question of technology

Technology is the primary challenge for directional drilling, according to Harry Engel, engineering team leader for BP's Alaska drilling and wells group, who spoke informally to state lawmakers on March 17.

"Can a field be developed with extended reach drilling? Sure it can. It's got to be the right field. It's got to be the right tools — the right drilling rig — and then the reservoir has to also match it," Engel said at a new five-session speakers' series sponsored by groups from various industries and taking place outside the normal hearing process.

Engel spoke on behalf of the Alaska Oil and Gas Association.

Engel said extended reach wells have a 1 to 3 ratio of vertical depth to horizontal reach.

The wells BP is proposing to drill to target the offshore Liberty prospect would push that boundary, dropping two miles underground before extending eight miles out, a 4-1 ratio.

"Liberty is going to be a tremendous learning round for industry on the limits of extended reach drilling," Engel said.

Engel said the primary technical challenge for this ultra-extended reach drilling is the rig.

The custom rig currently under construction for the Liberty project is expected to be the biggest in Alaska, capable of lifting millions of pounds of drilling string, with enough torque to turn a drill bit and enough pumping power to circulate drilling mud eight miles down and back.

Asked about the applicability of the technology at ANWR, Engel said, "It's hard to answer a question like that without knowing exact details on what we're talking about."

But he said engineers are already considering how best to drill even farther out. Ideas include switching from steel to aluminum tubulars to lighten the load on the drilling rig.

BP holds leases in ANWR, but has not been involved publicly in the debate for years. ●

—AP contributed to this report

NOTICE OF PROPOSED CHANGES IN THE REGULATIONS OF ALASKA DEPARTMENT OF NATURAL RESOURCES

The Department of Natural Resources proposes to adopt regulation changes in Title 11 of the Alaska Administrative Code, dealing with the methods and procedures used in reporting calculations of net profit share payments due the state for the production of oil and gas from net profit share leases (NPSLs) issued by the department. These proposed changes are intended to update and clarify existing regulations to accommodate the passage of significant changes to the Oil and Gas production tax ("production tax") in Alaska Statute 43.55 in 2006 and 2007. Proposed changes to the regulations, if adopted, will be retroactive to April 1, 2006.

Current NPSL regulations allow lessees to deduct production taxes on a per lease basis. The proposed amendments are intended to bring the current NPSL regulations in conformance with amendments to the production tax by providing a mechanism to calculate a deemed production tax for individual leases. Proposed amendments include:

1. Amending 11 AAC 83.209 (Production revenue account) to establish the manner in which the production tax carried-forward annual loss credit will affect NPSL reporting.

2. Repealing and readopting 11 AAC 83.212 (Development account) to establish how credits under the production tax and exploration incentive credits will affect NPSL reporting.

3. Adding a new section, 11 AAC 83.220, to establish the manner in which the production tax qualified capital expenditure credit and carried-forward annual loss credit will affect NPSL reporting.

4. Amending 11 AAC 83.240 (Direct operating costs) to clarify that the amount of tax liability imposed on the value of oil and gas production under the production tax, as amended in 2006 and 2007, is a direct operating cost for NPSL reporting.

5. Adding a new section, 11 AAC 83.241, to establish the method for calculating the monthly production tax liability to be recognized as a direct operating cost of an individual NPSL for purposes of NPSL reporting.

6. Repealing 11 AAC 83.245(a) and repealing and readopting 11 AAC 83.245(b) (reporting and payment requirements) to establish guidelines relating to NPSL reporting, including the dates NPSL reports will be due, the information required to be reported, and other reporting issues.

You may comment on the proposed regulation changes, including the potential costs to private persons of complying with the proposed changes, by submitting written comments to the Division of Oil and Gas, Attn: Christina Holmgren at 550 W. 7th Ave., Suite 800, Anchorage, AK 99501; fax 907-269-8938; e-mail christina.holmgren@alaska.gov. Comments must be received no later than 5 p.m. on April 28, 2009.

A public workshop on draft forms and instructions for NPSL reporting based on the proposed changes in regulation will be held in Room 602 of the Atwood Building at 550 West 7th Avenue, Anchorage Alaska, on Thursday, April 16, 2009, from 9:00 a.m. to 12:00 p.m. This workshop is for informational purposes only. No public comment will be taken during the workshop. Interested parties outside of Anchorage are invited to participate by teleconference and through an Internet-based LiveMeeting. Please contact Christina Holmgren at christina.holmgren@alaska.gov; 907-269-8611 for access information.

If you are a person with a disability who needs special accommodation in order to participate in this process, please contact Christina Holmgren at 269-8611 no later than April 3, 2009, to ensure that any necessary accommodations are provided.

For a copy of the proposed regulation changes, contact Christina Holmgren at 550 W. 7th Ave., Suite 800, Anchorage, AK 99501; by phone at 269-8611, or by e-mail at christina.holmgren@alaska.gov; or visit the Division of Oil and Gas Web site at www.dog.dnr.state.ak.us/oil/.

After the public comment period ends, the Alaska Department of Natural Resources will either adopt these or other provisions dealing with the same subject, without further notice, or decide to take no action on them. The language of the final regulations may be different from that of the proposed regulations. YOU SHOULD COMMENT DURING THE TIME ALLOWED IF YOUR INTERESTS COULD BE AFFECTED. Written comments received are public records and are subject to public inspection.

Statutory Authority: AS 38.05.020; AS 38.05.180; Sec. 72, ch. 1, SSSLA 2007.
Statutes Being Implemented, Interpreted, or Made Specific: AS 38.05.180
Fiscal Information: The proposed regulation changes are not expected to require an increased appropriation.

DATE: March 20, 2009

Kevin R. Banks
Director

FINANCE & ECONOMY

Alaska PFD payments expected to shrink

Proposal in Senate would stabilize permanent fund dividends, now expected to shrink to under $100 in 2013, fund managers say

THE ASSOCIATED PRESS

Alaska Permanent Fund dividends could dwindle over the next four years to as little as $68 in 2013, according to projections by fund managers.

Mike Burns, executive director of the $27 billion oil-wealth savings account, testified March 12 in Juneau on a Senate resolution that would change how the state pays out dividends. The measure would level out payments to compensate for lean or fat years.

BERT STEDMAN

Under the currents system, dividends are expected to exceed $1,500 this year but likely will shrink sharply, Burns said, because of large losses on fund investments, especially stocks.

He projected dividends would fall to $845 next year, bottom out in 2013, then rise again to as much as $1,771 in 2018.

He said the projections are not guaranteed and depend on assumptions such as an 8 percent annual gain on investments and other factors such as changes in the fund's investment approach.

Burns testified as the Senate Finance Committee considered Senate Joint Resolution 9.

Constitutional change proposed

The resolution, if approved by voters, would revise how the state pays for dividends, creating a system that would produce a steady dividend of more than $1,200 from 2010 through 2018, according to projections Burns provided the committee.

"Clearly, I think there's a concern that we come up with something that stabilizes the dividend stream. Because it's a big economic stimulus every fall for the state."
—Sen. Bert Stedman, R-Sitka

The Senate resolution would ask voters to approve constitutional amendments allowing legislators to spend up to 5 percent of the permanent fund's market value annually on dividends — and possibly other state expenses.

Dividends now come from fund profits, with dividends rising when profits are strong.

Sen. Bert Stedman, R-Sitka, calls the revised approach a "dividend stabilization plan." It would yield bigger dividends when fund investment returns are poor but could produce smaller dividends when investment results are strong.

Stedman said the plan would benefit Alaskans by creating a sizable dividend consistently each year. The fund could continue to grow because long-term investment gains are expected to beat the 5 percent legislators could spend out of the fund each year, he said.

Alaskans depend on the dividend, and a $68 payment will not sit well, Stedman said.

"Clearly, I think there's a concern that we come up with something that stabilizes the dividend stream. Because it's a big economic stimulus every fall for the state," he said.

Similar proposal failed in '04

The idea of amending the Alaska Constitution to change how the state pays the dividend is not new.

Stedman's proposal closely resembles an effort under former Gov. Frank Murkowski to amend the constitution to allow a 5 percent annual expenditure from the fund. The proposal was known as the "percent of market values" plan.

Murkowski wanted to allocate half the withdrawal to dividends and the other half to paying for government services. Permanent fund trustees strongly supported the POMV concept but legislators killed Murkowski's plan in 2004.

Stedman said March 12 he does not expect legislators to pass SJR 9 this session. Backers want to start the discussion with an eye toward passing the resolution next session so Alaskans can vote on the constitutional amendments in the 2010 general election, he said.

The 2008 dividend was the biggest ever at $2,069. The state added an extra $1,200 as a one-time "resource rebate" or share of the state oil revenue surplus.

The dividend is based on an average of the fund's profits over the previous five years. ●

continued from page 1

RUSSIA

Ottawa.

It evoked memories of Cold War days and prompted a stern rebuke from Prime Minister Stephen Harper, who said he would not tolerate the Russians breaching Canadian airspace.

"I have expressed at various times the deep concern our government has with increasingly aggressive Russian actions around the globe," he said. "We will continue to respond; we will defend our airspace."

Defense Minister Peter MacKay said two CF-18 fighter jets met at least one Russian bomber, although it later turned out there had been, in fact, two bombers.

Russia scoffed at Canada's assertion that it had given no advance notice of the flights.

An aide to Russian military chief of staff said the flights were planned and the crews acted within the limits of international air agreements and did not violate Canadian airspace.

But Russia has also warned that it will respond to any attempts to militarize the Arctic by stepping up its patrols.

"It's not a game," MacKay said. "I've personally asked both the Russian ambassador and my counterpart that we are given a heads-up when this type of air traffic is to occur. And to date we have not received that kind of notice."

"The statements from Canada's defense ministry are perplexing to say the least and cannot be called anything other than a farce," Russia's Interfax news agency quoted an unnamed source in the Russian government as saying.

The Russians took a slightly less strident tone during talks with Denmark, when the two countries agreed that the battle for the Arctic's oil and gas reserves — which also involves the United States, Canada and Norway — can only be resolved through international law.

Russians cite Arctic Council

Russian Foreign Minister Sergei Lavrov told a news briefing that "all problems in the Arctic, including climate change and reducing ice cover, can be successfully considered and resolved within specially created international organizations such as the Arctic Council."

But Canada also seems to be hedging its bets by updating the U.S. on its efforts to militarize the Arctic and ease U.S. concerns about security threats in the region.

Denmark's Foreign Minister Pier Stig Moller agreed that "international law should be used if there are contradicting claims from different states."

The council was established in 1996 and includes the five countries with Arctic coastlines, who are allowed a 200-mile economic zone north of their shores, plus the Faroe Islands and Iceland, which lie just outside the Arctic Circle. It agreed 10 months ago to follow the United Nations convention on the Arctic.

But the battle now extends far beyond the economic zones as the Arctic icecap retreats, opening the way to eventual oil and gas exploration during the summer.

For Russia, one of the keys is an underwater ridge that links Siberia with the Arctic and where it plans to claim a sprawling section of the seabed which has an estimated 13 percent of the world's undiscovered oil and 30 percent of its undiscovered gas.

Cannon later said Canada wants to work with Russia to advance their "common interests" in the Arctic in an overture that appeared designed to defuse the simmering tension that started in 2007 when a Russian submarine planted a flag under the North Pole.

Canada hedging its bets

But Canada also seems to be hedging its bets by updating the U.S. on its efforts to militarize the Arctic and ease U.S. concerns about security threats in the region.

The Harper government plans to spend billions of dollars building six to eight offshore patrol vessels capable of breaking up first-year ice; establishing a refueling site in Nunavut Territory; and constructing a new C$720 million icebreaker scheduled to replace its existing icebreaker in 2017.

It is also expected that Cannon will present Clinton with a convincing legal case that there is no history of the Northwest Passage being used as an international waterway. It has been used by U.S. ships three times since 1904 without Canadian permission, although on two occasions Canadian icebreakers were needed to rescue the ice-bound U.S. ships.

However, the U.S. shows no signs of backing down from its insistence that it has freedom of navigation within the Northwest Passage.

Canadian government sources say Russia's drive to extend its border north by 150 miles and add about 20 percent to its oil and gas reserves, along with worries about a new Cold War, should give Cannon and Clinton the incentive to ensure that the Northwest Passage does not become the final stumbling block to the Arctic sovereignty debate. ●

Petroleum news

Business Spotlight

MRO Sales Inc.

FORREST CRANE

Donny Powell Jr., Sales

MRO Sales Inc. is an Alaska-incorporated manufacturer's representative company involved in oilfield, mining and government sales. Projects range from Prudhoe Bay to the end of the Aleutian Chain. In November 1999 Petroleum Equipment & Services Inc. purchased MRO Sales. While the companies represent two profit centers, there is significant synergy from the merger and a bright future forecasted.

Donny Powell Jr., a sales representative at MRO Sales, has been with company for nine years, starting in the warehouse. He has a background in construction, mechanics and sales and has even spent some time bartending. In his off time he enjoys building and repairing classic cars. Currently Donny lives in Anchorage with his wife Pauline and son Don III.

—MARTI REEVE

Engineered Fire and Safety

FORREST CRANE

Kyle Thomas, Service Coordinator

Engineered Fire and Safety has been servicing Alaska's industrial, commercial, and residential fire protection needs for more than 20 years. A UTC Corporation, EFS partners with companies such as Fenwal, Chemetron, Siemens, Marioff, Detector Electronics and Verex to provide the latest fire and security technology to Alaska.

A former combat medic in the U.S. Army, Kyle Thomas later transferred the knowledge he gained in patient care to administration services and medical billing. Joining EFS in 2008, Kyle finds that those previous experiences have proven invaluable as he is challenged to find solutions for unique business needs. An avid bowler, Kyle hopes to qualify for the 2011 USBC Open in Reno, Nev. Most importantly he is a positive role model for his children Garrison and Cheyanne.

—MARTI REEVE

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

Oil Patch Bits

Schlumberger expands deep reading portfolio

Schlumberger said March 16 that it was expanding its Deep Reading portfolio with the release of its new electromagnetic DeepLook-EM enhanced crosswell reservoir imaging and monitoring system, and the acquisition of crosswell seismic reservoir imaging technology. The second-generation DeepLook-EM system provides detailed resistivity profiles between wells up to 1 km apart using time-proven induction logging principles.

"DeepLook-EM and our recently acquired Z-Series crosswell seismic service bridge the resolution gap between well logs and surface measurements to provide customers answers at the reservoir scale," said Colin Hulme, technical director, Deep Reading, Schlumberger.

Schlumberger is the world's leading supplier of technology, integrated project management and information solutions to customers working in the oil and gas industry worldwide. Employing more than 87,000 people representing over 140 nationalities and working in approximately 80 countries, it provides the industry's widest range of products and services from exploration through production. For additional information visit www.slb.com/deeplook.

CH2M Hill, Enviance enter into formal partnership

CH2M Hill said March 10 that it has entered into a formal partnership with Enviance to provide its clients with a real-time, online system for environmental, health and safety compliance tracking, management and reporting. The new partnership gives CH2M Hill the ability to configure and market solutions for its clients built on and powered by the Enviance System platform.

"CH2M Hill is now able to enhance the value we provide our clients by offering solutions that are powered by Enviance," said Steve Gelman, CH2M Hill business group president of industrial systems.

Employee-owned CH2M Hill is headquartered near Denver, Colo., and is a global leader in engineering, procurement, construction, management and operations for government, civil, industrial and energy clients. It has been named by Fortune as one of the 100 best companies to work for 2009. For more information visit www.ch2mhill.com.

Schlumberger introduces new telemetry platform

Schlumberger said March 17 that it released its new Orion II telemetry platform. The new platform enables reliable communication with bottomhole assemblies whether drilling at high penetration rates or longer boreholes. The Orion II combines new data compression technology with new surface and downhole sensors that modulate and demodulate signals and overcome interference from drilling and rig noise, even in harsh environments.

"With Orion II, more quality data and higher resolution images can be transmitted at greater depths, enabling better drilling decisions to be made in real time," said Ian Falconer, Schlumberger's marketing manager, Drilling & Measurements. Schlumberger is the world's leading supplier of technology, integrated project management and information solutions to customers working in the oil and gas industry. For more information visit www.slb.com/orion2.

Editor's note: Expanded versions of these news items will appear in the next Arctic Oil & Gas Directory, which will be released in July.

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AGIA

year, "I certainly think that at this time we want to push forward with the AGIA process" and see what comes out of the open seasons.

Rep. John Coghill, R-North Pole, chairman of the House Rules Committee, said the fact that ConocoPhillips and BP are moving ahead with Denali gives him some confidence that the long-term outlook is better than the short-term. And TransCanada continues to move its project forward, he said, but, "If it's not economic, we need to know as soon as we can."

Resolution to re-evaluate

House Concurrent Resolution 12 was introduced by Reps. Jay Ramras, R-Fairbanks, and Craig Johnson, R-Anchorage, and calls on the governor and attorney general to review and re-evaluate the license issued to TransCanada Alaska in light of the global economic recession's potential risks for project financing. A report would be due to the Legislature within 180 days of passage of the resolution.


TOM IRWIN

"In the private sector, you vet an issue and then you re-vet it when there are market changes — when conditions in the marketplace change. Only government is capable of setting a course and never deviating from it," Ramras said.

Johnson asked: "Is it still the right call today? If we had it to do all over again, would we change anything? And that's what we want the administration to go look at."

The resolution is scheduled for a hearing in the House Special Committee on Energy March 19 and in House Resources March 23.

House Democrats disagree

In a House Minority press conference March 17, Democrats supported AGIA and the TransCanada Alaska license.

House Minority Leader Beth Kerttula of Juneau said the state "took the biggest step forward that we possibly could have last session and ... we've now committed ourselves to this process."

"I think it's important to see how that process matures and to take it forward and I intend to work very hard to do just that," she said.

Rep. Les Gara of Anchorage said he understands "that there are folks who have opposed this gas pipeline for a long time. They had their opportunity last year and the Legislature decided to move ahead." He said there is nothing wrong with continuing to push things you believe in. "I respect that," he said, "but there's nothing that's changed that all of a sudden says, 'hey we can't do a gas pipeline now; let's just trash this whole contract.'"

"The oil companies, TransCanada, all of the major financial players knew last year what some of the legislators are just learning now, that there are other competing gas sources out there." Gara also said he believes that without the state pushing forward on a gas pipeline, "if any legislators succeed in stopping the TransCanada proposal, the Denali proposal disappears too and we don't get a gas pipeline."

Rep. David Guttenberg of Fairbanks said this is the closest in 30 years that Alaska has come to a gas line. Legislators have gotten a "phenomenal education" on pipeline economics and construction costs in the last few years, he said. Pipeline economics, he said, are based "not on today's prices — it's on some larger calculation on what prices are going to be over a period of time."

Rep. Berta Gardner of Anchorage said while Alaskans don't see backhoes moving on the project, Federal Coordinator Drue Pearce told legislators who were in Washington, D.C., for the Energy Council earlier in March that things are moving "fast and furious behind the scenes," with TransCanada on an aggressive timeline which Denali is matching. Gardner said from her perspective the state is in a battle with the producers, a battle to open the state "for business for new explorers and new development; and that's where Alaska's future is and that's why it's so important to have this independent pipeline and that is why we want to go to the FERC even if the producers say at the first open season that they're not going to ship the gas."

Gara said he had spoken to Joe Balash, the governor's energy aide, and to Commissioner of Natural Resources Tom Irwin. Both, he said, were concerned about the resolution, fearing it could kill a gas pipeline. Gara said they asked for a response from the administration.

Administration speaks

The administration, in a March 18 press conference headlined by Gov. Sarah Palin and Irwin, characterized issues that have arisen since AGIA was passed in 2007 and the TransCanada Alaska AGIA license issued in 2008 as short-term.

AGIA Coordinator Mark Myers, until recently head of the U.S. Geological Survey in Washington, D.C., said the decline in energy use is only temporary, but exploration is declining because of low prices. As supplies decrease there will be more demand and projects closer to completion will move forward.


MARK MYERS

"AGIA is a contract," the governor said. The state expects the oil and gas industry in Alaska to abide by their agreements with Alaskans and the state also needs to abide by its agreements.

The governor said her interpretation of the resolution is that it is a call for double checking and triple checking: The administration is happy to do that, she said, but doesn't believe the resolution is necessary.

Myers addressed the shale gas issue — large supplies in North America are of concern to some legislators as competition for North Slope gas.

"I'm a big fan of shale gas," Myers said, but it's "fairly expensive." While the in-place numbers for shale gas are very large, you need to look at how much is economically recoverable at what price — and that, he said, is a much smaller number than the total resource.

Myers said shale gas will provide a bridge until Alaska's gas is flowing in 2018. Shale gas doesn't supplant Alaska's gas, it only helps support and build a case for Alaska's gas in Lower 48 markets, he said.

Not off again, on again

There's no way in a project this size that you're on today, off tomorrow, on the next day, Irwin said.

He said the administration is more confident than ever that AGIA is driving an Alaska gas pipeline forward: Two and a half years ago we were wondering what we were going to do, he said, and now we have two projects — and companies exploring for gas.

"We're encouraged and we need to stay the course," Irwin said.

Asked what the administration is doing to get gas into a line, Irwin said the state has had conversations with the three gas owners, but before any decisions are made cost numbers — real numbers — are needed. TransCanada is doing a real design, Irwin said, and is excellent at reaching out and talking with the producers.

As for fiscal certainty, Palin said the administration is continuing to meet with the producers, but is not at the point yet where something would be brought to legislators.

"We're always willing to talk," Irwin said, and the administration has asked the producers what they need. Once the state has a design and real costs of a pipeline it can understand much better where the project could or should go. And real design work is being done today, he said.

In producers' hands

On the issue of fiscal certainty, Palin said a lot depends on what the producers of the gas are going to request. She said that discussion hasn't happened yet, so a lot of it is still in the producers' hands.

The governor said she was open to changes in the fiscal system to allow the project to happen. "We are open to whatever it takes to make sure it happens," she said.

But, she said, this time around discussions on tax certainty will take place "in the light of day" and politicians' votes won't be purchased this time around. That is the difference between AGIA and the prior process, the governor said.

The Stranded Gas Development Act, the process used by the prior administration, provided for confidential negotiations between the state and those proposing a gas pipeline.

AGIA eliminated those negotiations by establishing a process and inviting companies to bid for the state's AGIA license.

FERC pre-file

Denali has pre-filed with the Federal Energy Regulatory Commission, and the group was asked why TransCanada hasn't pre-filed.

TransCanada has said in the past that it is a cost issue, and Joe Balash, the governor's energy aide, said the same thing, that he understands it is reticence on costs, because once a company pre-files, FERC begins hiring consultants and staff and all of that adds to cost.

Balash said TransCanada's schedule calls for pre-filing after the open season in 2010, which is the process TransCanada has used in the past.

He noted that pre-filing in a typical case requires reports, but FERC waived those draft resource reports for the Denali pre-filing. Balash called it a little bit of chicken and egg: Draft resource reports normally required don't exist and won't exist until later this year for either project, he said.

Commenting on the issue of costs, Irwin said he believes "the most economic pipeline is the one that will get built." He said it will be interesting to see how the economics turn out, adding that every ad that's run is in the tariff bill.

Asked about the $500 million the state is contributing — in reimbursement for specified TransCanada activities — Palin asked why legislators don't remember that 59 of 60 voted in favor of AGIA and the $500 million provision.

The $500 million is in exchange for must haves in AGIA which protect the state's sovereignty, the governor said.

Irwin said the $500 million represents an investment by a resource owner in development. He also said that the $500 million reduces the tariff, and calculations have shown that the state will get the $500 million back through that reduced tariff. ●

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REFINERY

Price cap removed from bill

Alaska refineries like Flint Hills took heat last year as gasoline prices in Alaska "decoupled" from Lower 48 prices, staying high while average prices fell nationally.

Cook's comments came in the context of a hearing before the Senate Special Committee on Energy on a bill to prevent price gouging on gasoline and other refined products.

The bill, Senate Bill 54, originally tied Alaska prices to those in Washington State, restricting refineries like Tesoro and Flint Hills from charging more than 10 percent above the average price of similar products in Washington State, or face fines.

The bill's sponsor, Sen. Bill Wielechowski, an Anchorage Democrat, said he removed the price cap provision following concerned testimony from refineries at a February hearing.

"We think it still keeps the bill strong and continues to accomplish the objective," Wielechowski said.

Without the cap, though, the proposed legislation becomes less concrete about what actually constitutes "excessive" or "exorbitant" pricing, according to Ed Sniffen, an assistant attorney general in the consumer protection division of the Department of Law.

Alaska case law doesn't currently define those terms, but if other states ever try to enforce similar laws, Alaska could get some guidance on the terminology, Sniffen said.

"It is a very broad and undefined standard. We'll just have to work with it as best we can," Sniffen said.


COURTESY FLINT HILLS

The Flint Hills refinery

Most price gouging laws across the country only go into effect during natural disasters or states of emergency, when public officials hope to prevent retailers from significantly marking prices based solely on emergency demand, not on increased costs, Sniffen said.

A committee substitute of the bill changed a piece of the bill that would have allowed individuals to take action against companies under the Consumer Protection Act.

It also lowered the fine against companies caught violating the act.

Wholesalers and retailers

Some rural lawmakers want the bill expanded to cover fuel oil wholesalers across Alaska.

"What about other areas? Wholesalers and retailers. Why wasn't this legislation more broad?" said Sen. Lyman Hoffman, a Democrat from Bethel, a rural hub where fuel oil is delivered annually in bulk shipments. Many smaller communities in Western Alaska get their fuel oil from a single provider, leading to monopolies and non-competitive pricing.

The issue is similar in the Southeast, where fuel oil is shipped up from Seattle.

"The issue is broader than a refinery issue," said Sen. Burt Stedman, a Republican from Sitka, an island fishing community in the Southeastern Panhandle of the state.

The committee substitute expanded the bill to also include fuel wholesalers and retailers.

Sen. Lesil McGuire, an Anchorage Republican and chair of the Senate Special Committee on Energy, said she understood the concerns about the original bill, specifically the link to Washington State, but said the revisions address those concerns.

"Having this tool in the state's arsenal is appropriate," she said.

In a public hearing before the Senate Resources Committee on March 18, the bill received nine comments in favor and three opposed. The opposition included Cook, with Flint Hills, and Kip Knudson, with Tesoro Alaska.

"Clearly, if this is a good bill for Alaska consumers, I would urge you to expand it to all commercial transactions," Knudson said.

—ERIC LIDJI

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GUBIK

In testimony before Alaska lawmakers in February, Anadarko spokesman Mark Hanley said the company completed Gubik No. 3 and started Chandler No. 1 last winter. Hanley said Anadarko found gas at Gubik, but needed additional wells to prove up the resource.

Petro-Canada is an equity partner in the drilling program, along with BG E&P.

First new Gubik figures

The test rate offered by Petro-Canada is the first concrete figure given for the program.

It's also the first new figure to come out of Gubik in almost 60 years, since drilling crews with the U.S. Geological Survey used results from the first two Gubik exploration wells in the early 1950s to estimate that the field contained 600 billion cubic feet of natural gas.

Policymakers and the public have been closely following recent work at Gubik, which began in 1998 when Anadarko acquired more than 3.3 million acres in leases across the region, and picked up in 2007 when the three partners announced plans to look for gas.

The program is the first to explicitly target natural gas in northern Alaska. Previous natural gas discoveries came accidentally in the course of searching for oil deposits.

Currently, there is no system in Alaska to move northern natural gas to market.

Some see the Gubik exploration program as a sign Anadarko believes a gas pipeline will be built. Others believe the Gubik Complex could replace declining Cook Inlet reserves.

Petro-Canada acknowledged the uncertain nature of the exploration effort.

"The development of discoveries in this area will depend on the establishment of pipeline infrastructure, including a possible intra-Alaska line running south to service the Fairbanks and Anchorage areas," Petro-Canada wrote in its year-end financial filings.

The state recently involved itself in an effort to study a 500 million-cubic-foot per-day pipeline from the North Slope to Anchorage, a project commonly called the "bullet line."

With sufficient reserves, the Gubik Complex could theoretically supply this pipeline.

But the 15 million-cubic-foot-per-day figure from Petro-Canada doesn't offer conclusive evidence of either the total size of Gubik or the eventual production rate at the field.

Work continues this year

Anadarko and its partners hope to complete three wells this winter.

Anadarko previously confirmed work is under way to finish Chandler No. 1 using Nabors rig 105-E. Once the well is completed, the company will use the rig to drill Gubik No. 4.

Concurrently, Anadarko plans to use the Doyon Arctic Fox rig to drill the Wolf Creek No. 4 well in the northwest planning area of the National Petroleum Reserve-Alaska.

Federal officials recently told Petroleum News that work has begun on Wolf Creek No. 4. ●

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GAS TAX

When discussion?

Open seasons are planned by both proposed pipelines — TransCanada Alaska and Denali, the BP-ConocoPhillips joint venture — in 2010. Since the state has committed to honor the tax in place at the time of the first binding open season for the first 10 years of gas sales, Galvin said that if legislators are going to consider changes to the fiscal system for gas, those would need to be put in place during next year's legislative session, before the open seasons.

If the administration were to propose changes, he said, it would need to present them to the Legislature at or before the beginning of the session.

He reiterated that the administration's view is that — barring unexpected new information from the shippers or the pipeline — no changes are needed in ACES to accommodate natural gas taxation.

Asked when new cost information would be available, Galvin said TransCanada Alaska will include its new cost information in its open season applications to the Federal Energy Regulatory Commission, expected to be submitted early next year.

That information would provide the administration with the most up-to-date information on tariff cost estimates, Galvin said, adding that the administration hasn't received any information to date that cost estimates used during the AGIA special session last year need to be revisited. He said information they are hearing anecdotally indicates last year's costs "may be too high because of the environment that we were in at that point vs. the environment that we're in right now."

Wielechowski said he was concerned about project economics, with the credit crunch and Lower 48 supplies of shale gas.

Galvin said shale gas and liquefied natural gas issues, as well as the current credit crunch, "are all short-term issues over the next four to five years." He said the administration's energy consultants told him early in March that current changes in the gas market are short-term effects and that the long-term expectations for both gas prices and gas supply, as well as credit issues, remain those from the AGIA process last summer.

Committee may propose changes

Members of the committee were clearly looking at changing the gas fiscal regime.

Stedman said it took the Legislature years to deal with changes in the oil production tax. Changes were proposed and finally passed under the Murkowski administration in a special session after months of discussion and debate; further changes were made with ACES in another special session during the Palin administration.

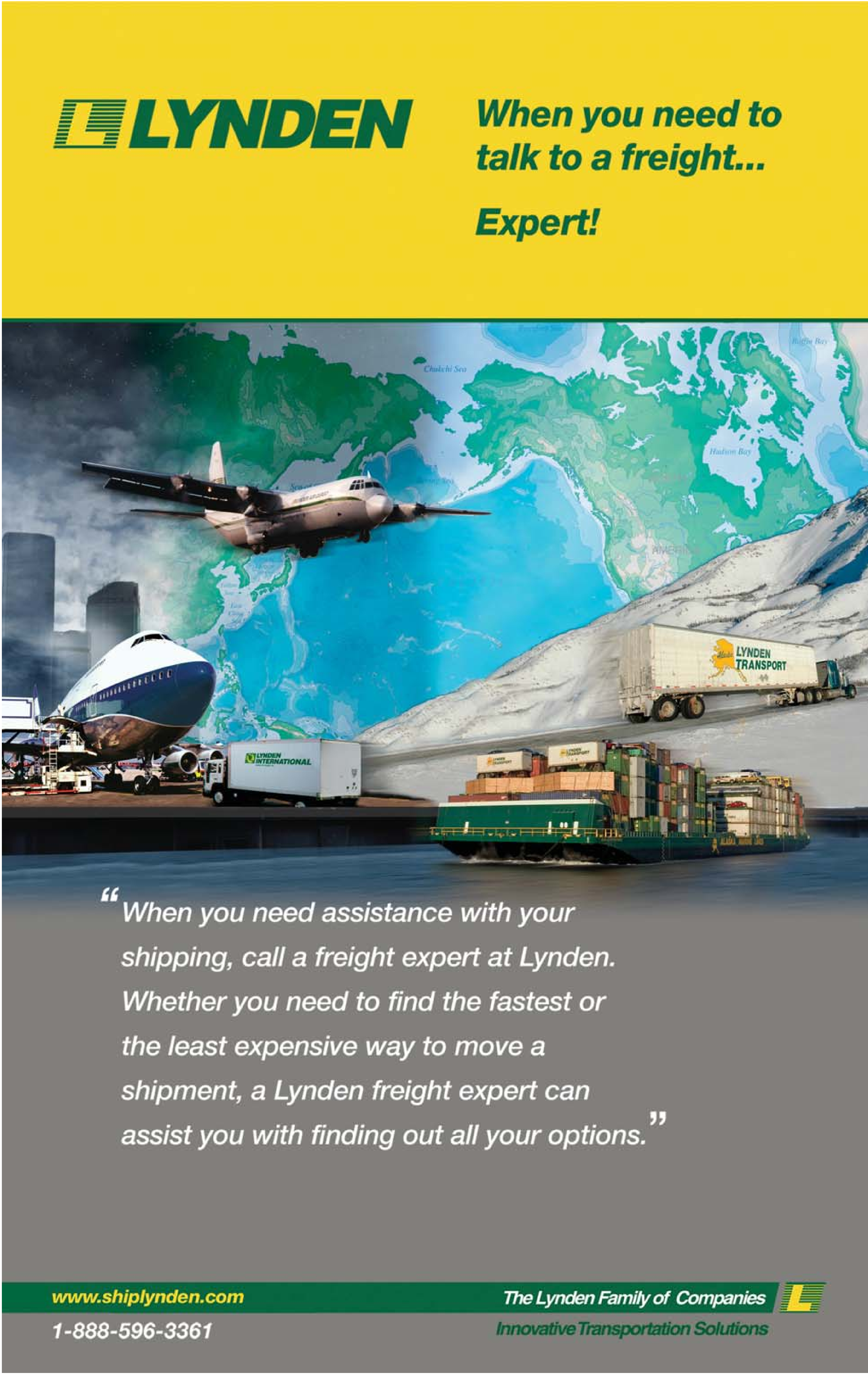
"We can't do it in 90 days," he said.

Denali's open season is scheduled for July 2010, and Stedman said he was sure it would take time for the Legislature to work out its own differences of opinion, as well as differences of opinion with the administration over a gas fiscal system, and said if agreement can't be reached in next year's 90-day session, the Legislature could add risk to the open season.

McGuire said the number one priority for Senate Resources — set at the beginning of the session — was to look at the gas tax structure so that legislators don't run up against dealing with it in next year's 90-day session just prior to an open season.

The committee has talked about introducing legislation on a gas fiscal system, "and we're not ruling that out," she said.

The committee would like to continue discussing the gas fiscal regime with the administration, McGuire told Galvin, and said "the interim might be an opportunity to really tackle some of the big issues surrounding this kind of a major change in the fiscal system." ●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