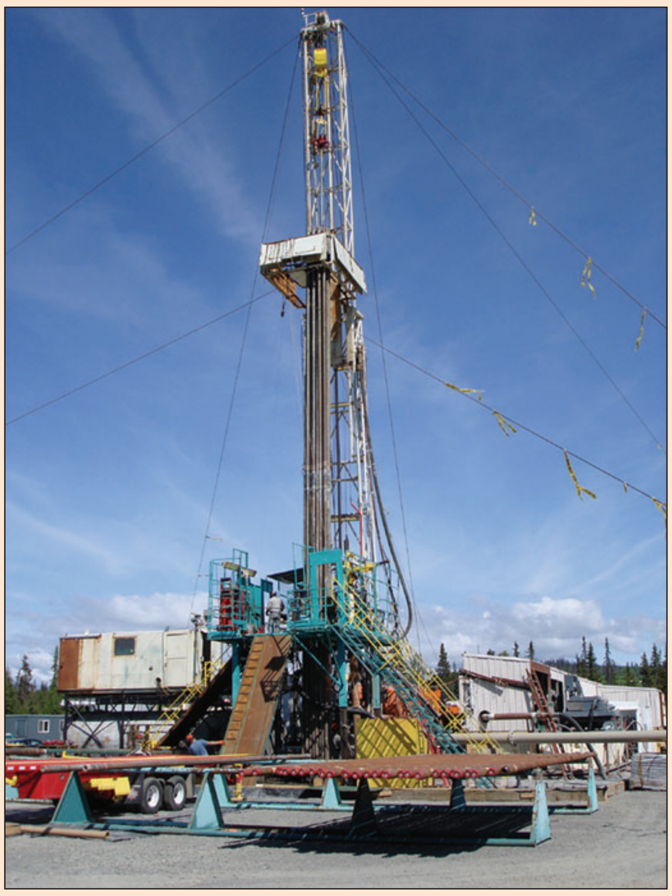
Petroleum news

Vol. 15, No. 34 • www.PetroleumNews.com | *A weekly oil & gas newspaper based in Anchorage, Alaska* | Week of August 22, 2010 • $2

page 7 Murkowski: Obama administration limiting Alaska resource development



COURTESY AURORA GAS

Aurora says that it will use its AWS No. 1 drilling rig to re-enter the Cohoe No. 1 well to test for natural gas.

Looking at Cohoe: Aurora wants to test old Kasilof well for gas

JUDY PATRICK

SCOTT PFOFF

Faced with the pending expiry of some state leases southwest of Soldotna on Alaska's Kenai Peninsula, Aurora Gas has filed paperwork with Alaska's Division of Oil and Gas to re-enter the Cohoe No. 1 well, to test for natural gas.

The company is negotiating with the Alaska Department of Natural Resources over possible unitization of the leases, which expire on Sept. 30, Aurora Gas President Scott Pfoff told Petroleum News Aug. 18. The unitization agreement would include a commitment to shoot some 3-D seismic in the leases, Pfoff said.

But Aurora has filed the drilling paperwork in case the unitization deal falls through.

see **COHOE WELL** *page 14*

DOT&PF studies compressed natural gas to power state's fleet

The Department of Transportation and Public Facilities is studying whether Alaska would benefit economically and environmentally by using natural gas instead of crude oil products like diesel and gasoline to fuel the more than 7,500 vehicles owned by the state.

The Division of Statewide Equipment Fleet plans to spend up to $65,000 on a study, due by the end of the year, which could lead to a compressed natural gas pilot program.

Like the name suggests, compressed natural gas, or CNG, is highly pressurized methane, reduced to a fraction of its original volume and store in special pressurized containers.

CNG can be used as a transportation fuel in special engines.

The Alaska Sustainable Energy Act, also known as Senate Bill 220, an energy policy bill passed earlier this year, mandated the study. The legislation described fleet conversion as a possible short-term solution for rising energy costs in Alaska, and paired it with a policy for the state to consider long-term energy costs

see **CNG** *page 14*

PIPELINES & DOWNSTREAM

Jet fuel due from Japan

Cosmo Oil to supply Anchorage air cargo hub with up to 300,000 bbl monthly

By WESLEY LOY

For Petroleum News

A Japanese oil refiner is seeking permission to bring jet fuel by tanker into the Port of Anchorage, a move that could help cure what has been a costly problem for the air cargo industry.

Cosmo Oil of USA Inc., a Torrance, Calif., affiliate of Tokyo-based Cosmo Oil Co. Ltd., on July 10 applied to the Alaska Department of Environmental Conservation for an oil discharge prevention and contingency plan, or C-plan.

Oil and fuel shippers are required to have a highly detailed plan for responding to spills before they can operate in state waters.

If Cosmo's plan is approved, it will be the second fuel provider to recently obtain permission to ship jet fuel through Cook Inlet to the Port of Anchorage.

The big jet fuel producer is Flint Hills, which sends its output by train to Anchorage. Flint Hills production, however, has been irregular as the company struggles to make the plant economic.

On July 30, DEC officials approved a C-plan amendment to allow Anchorage-headquartered Delta Western Inc. to bring tank vessels into Cook Inlet. Delta Western is a major distributor of fuel

see **COSMO OIL** *page 13*

FINANCE & ECONOMY

Rolling with the rollback

Alberta royalty reduction starts to show up in corporate bottom lines, drilling

By GARY PARK

For Petroleum News

The jury is not quite done with its work, but the early verdict is a happy one all-round.

It shapes up like a win-win for the Alberta government and the petroleum industry as the trickle-down from the province's latest attempt to get its royalty changes sorted out starts to show up in corporate bottom lines as well as upstream activity.

Consider one company — PetroBakken. The net value of its Alberta wells has been raised by C$1 million apiece, enough, according to analysts, to pay for about half of the company's recent C$1 billion buying binge.

The reduction in Alberta royalties has also allowed Vero Energy to pump the value of its wells by C$937,500 each, or an increase of 20-30 percent, while junior E&P Anderson Energy is selling off its surplus drilling incentives.

Drilling up

Of more direct importance to the government, the number of drilling rigs at work in Western Canada — where Alberta dominates activity — is 378 compared with 157 at the same time last year. In Alberta, the active rig count has soared to 242 from 84.

Don Herring, president of the Canadian Association of Oilwell Drilling Contractors, said the numbers are approaching a level his sector is much happier with.

see **ROLLBACK** *page 15*

EXPLORATION & PRODUCTION

Seeking opportunities

DGGS-led team continues multiyear investigation of Cook Inlet petroleum geology

By ALAN BAILEY

Petroleum News

Dwindling oil production, tightening product deliverability and an aging infrastructure are normally the hallmarks of a mature oil and gas province. But Alaska's Cook Inlet basin, despite its collection of aging oil and gas fields, remains in many geologists' eyes relatively underexplored, especially given the sparse distribution of exploration wells in the region.

So, as residents of Southcentral Alaska become increasingly jittery about ever tightening natural gas supplies for power generation and heating, and as Southcentral Alaska's main oil refinery at Nikiski on the Kenai Peninsula has to import more and more of its feedstock, are there still significant oil and gas resources to be found in the region? Or is the end in sight for the basin that triggered Alaska's first major oil and gas production, before the discovery of oil on the North Slope?

And, in parallel with the DGGS work, the U.S. Geological Survey plans to conduct a new oil and gas assessment of the Cook Inlet basin in early 2011.

A team of geoscientists led by Alaska's Division of Geological and Geophysical Surveys, in a spirit of optimism about the continuing potential of the Cook Inlet basin, has been engaged in a multiyear project investigating the petroleum geology of the region and

see **COOK INLET GEOLOGY** *page 15*

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Petroleum News *North America's source for oil and gas news*

● GOVERNMENT

Canadian Senate opposes offshore ban

By GARY PARK

For Petroleum News

There is no need to ban drilling in Canadian coastal waters, given that current legislation and the regulatory regime is "among the most stringent and innovative in the world," the Canadian Senate's energy, environment and natural resources committee said Aug. 18.

Wrapping up six weeks of public hearings in the aftermath of BP's Macondo well blowout, the bipartisan committee rejected calls for a moratorium in the Atlantic region, where Chevron Canada is drilling its Lona O-55 well in 8,500 feet of water in Newfoundland's Orphan basin. It saw no reason why a calamity on the scale of the Gulf of Mexico spill could occur in Canada.

Chevron started drilling the Lona well on May 9, barely three weeks after the explosion on BP's Deepwater Horizon rig.

"The offshore industry is a very risky one and a highly costly one and to interrupt and stop an operation just because of possible fears isn't necessarily a wise course of action," said committee Chairman Sen. David Angus.

He said the committee was satisfied that "the regulatory regime in Canada, both provincial and federal, is a good one," based on evidence it heard from 26 witnesses, including regulatory experts and industry executives.

Sen. Grant Mitchell, a Liberal from Alberta, said the committee sought a balance between economic and environmental concerns.

He said the report emphasized the huge financial benefits that flow to Canada from allowing companies to explore and develop the offshore.

The committee did not examine the Arctic, which is under a comprehensive review by the National Energy Board, including the need for relief wells to be drilled in the same season as a blowout, or British Columbia's offshore, which is off limits to oil and gas exploration because of a post-Exxon Valdez moratorium.

Water deeper at Lona

Chevron's Lona well, which is being drilled in water much deeper than the Macondo well, is being conducted "under very careful supervisions. … We found no need or any justification or any evidence which would lead us to recommend that the operation be stopped," Angus said.

The committee recommended:

• Exploring in greater detail the structure and role of Canada's offshore petroleum boards (in Newfoundland and Nova Scotia) to determine whether there might be a material conflict between the boards' roles as promoters of development and environmental stewards;

• Greater collaboration between all those responsible for responding to an oil spill in developing, preparing and practicing in advance of an event;

• A comprehensive review of liability issues, including whether the thresholds should be adjusted to reflect current economic realities; and

• A thorough discussion by regulators and industry respecting whether and under what circumstances relief wells should be ordered. ●

Contact Gary Park through publisher@petroleumnews.com

● GOVERNMENT

AOGCC takes over Cook Inlet UCG wells

Wells deeper than 500 feet in two onshore areas where encounters with oil, gas likely now must have commission drilling permits

By KRISTEN NELSON

Petroleum News

The Alaska Oil and Gas Conservation Commission is asserting authority over wells drilled to depths greater than 500 feet in specified onshore areas of Cook Inlet.

At issue here are wells drilled to explore coal, which are permitted by the Department of Natural Resources, not by AOGCC. Last fall the commission asserted authority over geothermal wells in specific areas where there was the potential to encounter unexpected hydrocarbons. This spring the Alaska Legislature turned authority for geothermal drilling over to the commission.

The commission said in Conservation Order No. 631, dated Aug. 9, and aimed at underground coal gasification exploration wells, that wells drilled in specified areas of the Kenai Peninsula and the Matanuska-Susitna boroughs are "likely to have unexpected encounters of oil, gas or other hazardous substances," citing instances of blowouts or well control issues in shallow wells drilled in the area.

In a summary of its findings the commission said the onshore northwest Cook Inlet area "is known to be underlain by laterally extensive coal deposits" beginning near the surface.

"Increasing interest in unconventional energy sources including Underground Coal Gasification will likely result in exploratory drilling projects to assess the coal resource in the NW Cook Inlet area," the commission said.

There are multiple biogenically sourced natural gas fields in the northwest Cook Inlet area and throughout the basin and drilling records throughout the area "have established that natural gas can be encountered at shallow depth," with multiple natural gas fields developed on the west side of Cook Inlet in the townships and ranges designed for regulation.

Well control problems

The commission said its records indicate that at least three wells in the area have experienced well control problems while drilling at depths of about 1,500 feet or less, specifically the Moquawkie No. 1 (drilled in 1965,) which encountered shallow gas and experienced a blowout and fire while drilling at about 1,525 feet; the Moquawkie No. 4 (drilled in 2008) which experienced a blowout while drilling at about 900 feet; and the CC-4C-10 (drilled in 2010,) which encountered shallow gas and experienced a kick while drilling at about 1,320 feet.

The commission said it has no records indicating well control problems in the area at depths shallower than 500 feet.

According to a transcript of the commission's July 27 hearing on this issue, Art Saltmarsh, senior petroleum geologist at the commission, said the blowouts at the Moquawkie wells were controlled with heavy drilling muds — in the case of the Moquawkie No. 1 after the fire, which extensively damaged the rig, was put out. He said that in both of these cases it appeared the drilling fluid used initially wasn't sufficient to overbalance formation pressures.

The well drilled this year, the CC-4C-10, was one of five wells drilled by Cook Inlet Region Inc. in the vicinity of Forcenergy's 1998 Coffee Creek No. 1 well. Saltmarsh said that when Coffee Creek was drilled, the operator had to use mud weights in excess of 10 pounds per gallon while drilling at some 800 feet and more than 10.6 pounds per gallon while drilling at approximately 2,600 feet to suppress and contain formation gases encountered while drilling.

CIRI encountered shallow gas while drilling the CC-4C-10 well at about 1,320 feet and some 2,000 gallons of brackish drilling fluid was ejected from the wellbore. The blowout preventers were closed and the well was brought under control with heavier drilling mud and then cemented.

AOGCC worked with DNR

Underground coal gasification falls under the regulatory control of the coal regulatory group at DNR which issues permits for surface coal exploration and extraction.

Saltmarsh said that because of the high likelihood of encountering gas in the CIRI wells, senior AOGCC staff had worked with the coal regulatory group at DNR to ensure that proper blowout prevention equipment and sufficiently heavy drilling muds were used in the project.

Commissioner John Norman said at the hearing that under state statute the commission can exercise its authority to regulate drilling on nonconventional energy projects — the commission has statutory authority to regulate oil and gas drilling — if it finds that unexpected encounters with oil, gas or other hazardous substances is likely in a designated area. ●

Contact Kristen Nelson at knelson@petroleumnews.com

● UTILITIES

Chugach wants power plant guarantees

Utility asks RCA to decide whether power plant costs are prudent before construction begins as a way to get better financing

By ERIC LIDJI

For Petroleum News

As Chugach Electric Association gets ready to build a roughly $300 million power plant, the cooperative wants to know it will be able to recoup its expenses on the project.

The largest electric utility in Alaska is asking state regulators for a sign that some of the costs of its Southcentral Power Project can someday be passed on to ratepayers. Chugach said the assurance will help it secure better financing, leading to lower interest rates that would ultimately save ratepayers between $1 million to $2 million each year.

Chugach said it is not, however, asking to actually change its rates at this time.

Instead, Chugach wants the Regulatory Commission of Alaska to reiterate its support for the project and to assure potential investors that nearly $200 million in Chugach contracts can be included in electricity rates after the plant in brought into service around 2013.

While RCA sets electricity rates in the state, it doesn't have the authority to sign off on infrastructure projects, calling those "management decisions." That said, in 2008, when the question of whether Chugach should build a new power plant came up during a rate case, RCA found that Chugach reached its decision after "extensive analysis."

At the time, Chugach was deciding between repairing Beluga 8, an aging facility in its portfolio, or building a new power plant. After commissioning several studies, Chugach decided that the fuel savings alone would justify the added cost of a new power plant.

CEA wants reaffirmation

Chugach believed RCA's vote of confidence would be enough to assure lenders the project was prudent. Chugach maintained that belief even as credit markets tightened in late 2008, but recently decided it needs reaffirmation to get the best deal.

"After some initial reluctance by a potential lender, Chugach was still convinced that after credit markets settled, it could proceed without a prior prudency review," Michael Cunningham, chief financial officer for Chugach, told RCA. "However, Chugach has concluded that the least cost financing will be obtained if it first obtains a determination of prudence and assurance of cost recovery as proposed in the accompanying petition."

The idea of regulators signaling their intentions to potential investors is not new, according to Karl McDermott, a utility consultant hired by Chugach to review the case.

In testimony filed alongside Chugach's request, McDermott said regulators in the Lower 48 have been using similar tactics for more than 30 years, anytime generation is added.

The general idea is to make utilities study the available options before building a new project and then to use those studies to get a nod from regulators before construction begins. The process doesn't stand in for a review of costs later on, McDermott said.

New facilities rare in Alaska

But new generation facilities are rare in Alaska. RCA asked Chugach to look for precedent, where state regulators guaranteed cost recovery in advance. It also asked Chugach to consider the precedent that might be set by making those guarantees now.

Chugach is looking to restructure its debt in October and wants RCA to rule by mid-September. RCA, which isn't statutorily required to rule until Dec. 27, is skeptical of that timeline, but suggested it could be persuaded if Chugach details an expedited review.

Chugach and Municipal Light & Power will jointly own the power plant. Chugach will manage the facility and own 70 percent of it, while ML&P will own the remainder.

The power plant will produce about 183 megawatts from three natural gas fired turbines. Chugach signed three contracts for the power plant this year worth $197 million and told RCA it is only currently looking for guidance on that $197 million.

Several parties in case

The case has attracted the attention of many players in Southcentral.

Alpine Energy and Tiqun Energy, two independent power companies, joined the case, concerned about how the outcome might impact proposed power projects in the region.

Homer Electric Association, the second-largest wholesale customer of Chugach electricity, also joined the case, saying it welcomed an RCA review as a way to independently verify whether Chugach did its due diligence in deciding to build the plant.

"HEA is aware that the new generating units on the market are more efficient and the selection of more efficient units would appear to be an acceptable option," the company wrote. "However, while HEA is supportive of Chugach's planning process, it is not in a position to verify that the contracting process or the resulting pricing were prudent."

HEA chose not to renew its contract with Chugach beyond the end of 2013.

ML&P also joined the case, at the request of RCA.

"While ML&P and Chugach are co-owners of the SPP project, their interests may differ in some respects and there is no assurance that Chugach, the only current party to this docket, will fully represent ML&P's interest," the municipal utility wrote in filings.

The Public Advocate, a section of the state Attorney General's office, is also joining the case. ●

Contact Eric Lidji at ericlidji@mac.com

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Kay Cashman	PUBLISHER & EXECUTIVE EDITOR
Mary Mack	CHIEF FINANCIAL OFFICER
Kristen Nelson	EDITOR-IN-CHIEF
Clint Lasley	GM & CIRCULATION DIRECTOR
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Forrest Crane	CONTRACT PHOTOGRAPHER
Tom Kearney	ADVERTISING DESIGN MANAGER
Amy Spittler	MARKETING CONSULTANT
Dee Cashman	CIRCULATION REPRESENTATIVE

ADDRESS
P.O. Box 231647
Anchorage, AK 99523-1647

NEWS
907.522.9469
publisher@petroleumnews.com

CIRCULATION
907.522.9469
circulation@petroleumnews.com

ADVERTISING
Susan Crane • 907.770.5592
scrane@petroleumnews.com

Bonnie Yonker • 425.483.9705
byonker@petroleumnews.com

FAX FOR ALL DEPARTMENTS
907.522.9583

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OWNER: Petroleum Newspapers of Alaska LLC (PNA)
Petroleum News (ISSN 1544-3612) • Vol. 15, No. 34 • Week of August 22, 2010
Published weekly. Address: 5441 Old Seward, #3, Anchorage, AK 99518
(Please mail ALL correspondence to:
P.O. Box 231647 Anchorage, AK 99523-1647)
Subscription prices in U.S. — $98.00 1 year, $176.00 2 years, $249.00 3 years
Canada — $185.95 1 year, $334.95 2 years, $473.95 3 years
Overseas (sent air mail) — $220.00 1 year, $396.00 2 years, $561.00 3 years
"Periodicals postage paid at Anchorage, AK 99502-9986."
POSTMASTER: Send address changes to Petroleum News, P.O. Box 231647 Anchorage, AK 99523-1647.

● PIPELINES & DOWNSTREAM

RCA agrees to consolidate rate cases

Regulators fold four 2009 rate cases into previously consolidated 2008 rate cases; parties proposing concurrent FERC-RCA hearing

By ERIC LIDJI
For Petroleum News

State regulators are consolidating eight cases on trans-Alaska oil pipeline shipping rates.

In a bid to simplify what is becoming an increasingly complicated situation, the Regulatory Commission of Alaska agreed to fold a series of rate increases requested by the owners of the pipeline in 2009 into a previously consolidated series from 2008.

The owners and several third parties, including the state, proposed the consolidation idea in January. The move allows the state and third parties that asked to be part of individual cases to participate in the larger rate case. The owners and the third parties, however, did not reach a decision about what information should be kept confidential during hearings. RCA plans to issue a decision on that matter in a future ruling.

The owners of the pipeline also said they intend to ask RCA and the Federal Energy Regulatory Commission to hold a concurrent hearing to decide whether costs associated with a major upgrade project on the pipeline should be included in shipping rates.

FERC regulates shipping rates on oil bound for markets outside of Alaska.

Transportation subsidiaries of BP, ConocoPhillips, ExxonMobil, Chevron and Koch each own an undivided stake in the 800-mile pipeline that goes from Prudhoe Bay to Valdez.

Nine cases in 20 months

While shipping rates are always a major regulatory issue for the pipeline owners, the past three years have brought an increasingly complicated tone to the usual proceedings.

Until 2008, the five companies that own stakes in the pipeline asked for rate increases using a methodology struck down in a landmark court ruling in 2002.

Every year, RCA in turn rejected those requests.

Starting in 2008, however, the companies began using the new methodology, saying that declining throughput and increasing operating costs justified higher shipping rates.

That year, four of the five owners asked the commission for permission to increase shipping rates on oil bound for Alaska markets by 57 percent. BP did not ask for a rate increase.

RCA approved those increases on a temporary basis while it looked into whether the increases should be set in place permanently. But In 2009, before RCA reached a decision, the four owners asked for an additional 29 percent increase. RCA also approved those increases on a temporary basis, creating eight similar rate cases.

ConocoPhillips recently requested a third rate increase. RCA has not decided whether or not to allow those new rates to go into effect on a temporary basis.

The commission previously consolidated the four 2008 cases into one docket. The new order consolidates the 2009 cases into the 2008 case, making one docket for all eight cases.

ConocoPhillips recently requested a third rate increase. RCA has not decided whether or not to allow those new rates to go into effect on a temporary basis.

A big SR question mark

One of the big points of debate in the rate cases is whether and how the owners should be allowed to include the costs from Strategic Reconfiguration in shipping rates.

The Strategic Reconfiguration project is a major upgrade to the pipeline and the pump stations along it that has been late and over budget. The state and several third parties don't believe the full cost of the program should be included in the rates paid by shippers.

RCA previously held off on setting hearings about the rate cases while it waited for FERC to set a timetable to deal with the Strategic Reconfiguration question.

The parties originally proposed the idea of phasing the rate cases, letting RCA consider everything not connected to Strategic Reconfiguration now while it waits for FERC to look at the Strategic Reconfiguration question. Now, though, the parties are proposing a concurrent hearing where state and federal regulators can hear the issues.

The commission previously consolidated the four 2008 cases into one docket. The new order consolidates the 2009 cases into the 2008 case, making one docket for all eight cases.

While the same companies that own the pipeline also own much of the oil moving through it, shipping rates impact other companies like independent North Slope producers and third-party refiners, and the state, which gets smaller royalties when shipping rates go up because royalties are calculated after tariffs have been paid. ●

Contact Eric Lidji at ericlidji@mac.com

GOVERNMENT

Talisman Energy eager to pay up

Talisman Energy has lost its patience with New York state lawmakers, telling them to copy Pennsylvania and impose higher regulatory fees to open the way for development of the state's portion of the Marcellus shale gas deposit.

Otherwise, the Canadian-based independent is faced with a drilling moratorium that will extend to at least next May, while the environmental impacts of shale gas production are examined.

Mark Scheuerman, Talisman's director of governmental affairs in the United States, told a conference call that New York should follow the example of Pennsylvania which hiked drilling permits by $4,000 per well from $100 to bolster its regulatory system.

The alternative for New York is to miss out on a potential windfall, he said, noting that Talisman's 13 wells in Pennsylvania will pump $12 million into government coffers.

"We're not saying we need to trade the economic equation for any unreasonable risk as far as impact at the surface or to other environmental locations," Scheuerman said.

If the state raises its fees, the Department of Environmental Protection would have the "wherewithal to turn around permits in a commercially acceptable timeframe that we need as a business, but, even more importantly, to exercise their prime directive to being solid environmental stewards," he said.

Local water use an issue

The arm wrestling between Talisman and the state mirrors the battle over the use of local water resources for the drilling and hydraulic fracturing techniques needed to exploit shale gas deposits.

Talisman is spending $1 billion this year to develop its Marcellus holdings, all of it in Pennsylvania, and is now producing 190 million cubic feet per day, aiming for 300 million cubic feet per day by year's end.

The U.S. Environmental Protection Agency is studying the effects of shale development on water sources, triggering a series of angry public hearings, including the postponement of one session in Syracuse when faced with security concerns.

Brad Gill, executive director of the Independent Oil and Gas Association of New York, said there has not been one documented case of hydraulic fracturing contaminating ground water.

Rachel Richler, chairwoman of the Sierra Club's shale gas task force in New York state, challenged that claim, saying there is ample circumstantial evidence of contamination, but she conceded the fact that tests have not been done before drilling makes it difficult to draw an absolute conclusion on the source of pollution.

—GARY PARK

● ENVIRONMENT & SAFETY

Oil sands toxins get airing in report

By GARY PARK

For Petroleum News

It's one of those "on the one hand on the other hand" debates.

In the four years from 2006 to 2009, volumes of arsenic and lead produced and deposited in tailings ponds at Canada's oil sands rose by 26 percent. Quantities of some other substances rose even faster.

But the unpleasant, often toxic byproducts of bitumen extraction accounted for only 10 percent of the total tailings and waste rock reported to the federal government.

But the unpleasant, often toxic byproducts of bitumen extraction accounted for only 10 percent of the total tailings and waste rock reported to the federal government.

The information was contained in the 2009 National Pollutant Release Inventory published by Environment Canada and covering all mining operations from bitumen to minerals.

David Collyer, president of the Canadian Association of Petroleum Producers, said the oil and gas industry is just one of the sectors that makes an impact.

"Transparency and reporting processes like the NPRI are essential to understanding industrial contaminants and balancing our need for environmental protection, economic growth and secure reliable supply of resources," he said.

In defense of his industry's efforts to improve its tailings pond performance, Collyer said more than C$1 billion will be spent over the next year on research and upgrades to reduce tailings inventories and speed up reclamation of the land, starting with Suncor Energy's first pond.

Tailings from oil sands

Tailings substances reported to Environment Canada originate in oil sands ore (clay, sands, water and bitumen) or are the results of processing to improve bitumen recovery.

They are contained in ponds to allow sand and clay to settle, with clarified water from the ponds being recycled, which covers 80-90 percent of the water used to extract oil from the oil sands, thus reducing the demand for fresh water.

On the flip side, the mining operators — Suncor, Syncrude Canada, Royal Dutch Shell and Canadian Natural Resources — released 70,658 metric tons of volatile organic compounds into the atmosphere last year, and 111,661 metric tons of sulfur dioxide, a leading contributor to acid rain.

The tally includes 322 metric tons of arsenic, 651 metric tons of lead and measurable volumes of mercury, chromium, vanadium, hydrogen sulfide and cadmium.

The latest numbers in the NPRI tracked 85 mining facilities, with metal ore mines delivering the worst results, generating 54 percent of tailings and waste rock, followed by iron ore mines at 25 percent. Other mines, including diamond, asbestos and phosphate, generated 5 percent.

Dangerous substances

But oil sands operations were pinned with contributing the bulk of several dangerous substances, which are blamed for tumors of the lung, skin and bladder; some are carcinogens.

Justin Duncan, an attorney with Ecojustice, which spearheaded a 2007 court case that forced Environment Canada to release the NPRI data, said that if one of the tailings ponds broke its banks, thousands of pounds of heavy metals would pose a "catastrophic risk" to the Athabasca River, the region's main water system.

Simon Dyer, oil sands program director for the Alberta-based Pembina Institute, told the Globe and Mail it is essential for more information to be made available and permit a "meaningful discussion about the unacceptable risk of these tailings ponds."

The four mining operators are currently developing new tailings technologies, while universities and agencies are researching new methods to accelerate the separation of water and silts, enabling faster recycling of water and faster returns of tailings areas to productive landscapes. ●

Contact Gary Park through publisher@petroleumnews.com

● GOVERNMENT

Murkowski slams Obama administration

Says that new legislation and federal regulations show that government sees Alaska natural resource development as a problem

By ALAN BAILEY
Petroleum News

Sen. Lisa Murkowski, in a speech to the World Trade Center Alaska on Aug. 17, blasted the federal government for what she characterized as overreach in applying legislation and regulations that limit Alaska's ability to develop its natural resources.

SEN. LISA MURKOWSKI

Reflecting on the tragic passing of former Sen. Ted Stevens, Murkowski said that resource development had been one of the central pillars of Stevens' vision of Alaska's future.

"He understood, perhaps better than anyone else, that our ability to develop a 'climate for investment' starts and ends with our ability to develop our natural resources," Murkowski said in remarks prepared for her speech. "This (resource) abundance accounts for a huge share of the jobs in our state, and the vast majority of revenues for our state government."

Off limits

But the cumulative effect of new rules and regulations from government agencies, and new legislation working its way through Congress, are placing more and more Alaska resources off limits, she said, citing examples such as the U.S. Environmental Protection Agency's re-opening of a challenge to a permit for the Kensington gold mine in Southeast Alaska, after a U.S. Supreme Court ruling upholding the validity of the permit.

In terms of the oil industry, an administrative decision to declare the Colville River as an "aquatic resource of national importance" and to subsequently prohibit the construction of a river bridge has thrown great uncertainty over the possibility of developing new oil resources in the National Petroleum Reserve-Alaska, Murkowski said. Murkowski also expressed strong concern that a recently announced intent by the U.S. Department of the Interior to develop a new NPR-A management plan could signal more areas of the reserve being excluded from oil development.

"If a company can't explore for oil in a national petroleum reserve during this administration, even after paying huge amounts of money for leases and spending years to work through the development process, then we can't honestly expect a rational approach to any oil and gas development," Murkowski said.

And Murkowski accused the administration of having a hidden agenda to restrict access to NPR-A in order to prevent the eventual construction of a pipeline from the Chukchi Sea across to the central North Slope, thereby throttling the possibility of development in a new high-potential Chukchi Sea oil province.

Drilling moratorium

Murkowski proceeded to accuse the administration of stifling Chukchi Sea development by imposing an Arctic outer continental shelf drilling moratorium in response to the Gulf of Mexico oil spill.

"Not wanting to let a crisis go to waste, the administration has also used the Deepwater Horizon tragedy to justify something else it wanted to do: cancel exploratory drilling 5,000 miles away, and in only 150 feet of water, in the very shallow seas off Alaska's north coast," Murkowski said.

In fact, the president has been giving speeches about the depletion of U.S. onshore and shallow-water oil fields while also taking two of the country's most promising oil provinces — the Chukchi Sea and NPR-A — off the table, Murkowski said.

And rather than considering compromise options for the development of oil from the Arctic National Wildlife Refuge 1002 area, the administration and Congress are setting the stage for designating the 1002 area as permanent wilderness, she said. A compromise proposal involving directional drilling into refuge resources from land outside the refuge met with "knee-jerk opposition," she said.

45 billion barrels

Taken together, the Chukchi Sea, NPR-A and the ANWR 1002 area could hold 45 billion barrels of undiscovered oil, enough oil to cut U.S. oil imports by half over the next 20 years, Murkowski said.

> *"Not wanting to let a crisis go to waste, the administration has also used the Deepwater Horizon tragedy to justify something else it wanted to do: cancel exploratory drilling 5,000 miles away, and in only 150 feet of water, in the very shallow seas off Alaska's north coast."*
> **—Sen. Lisa Murkowski, R-Alaska**

"The next time you hear someone say that the United States has 3 percent of the world's oil reserves but consumes 20 percent of its production, remember that Alaska's resources are purposely being left out of that calculation," Murkowski said.

It is also critically important to develop enough new Arctic Alaska oil resources to keep the trans-Alaska oil pipeline in operation, to prevent the future stranding of Arctic oil.

"If we continue to let the supply in this line diminish, operational issues will crop up within a decade and it could be shut down entirely," Murkowski said.

It is necessary to reverse the course that the administration has set for Alaska because resource development is the principal driver of Alaska's growth and prosperity, Murkowski re-iterated.

"We can use our resources to create prosperity and develop a strong economy while still protecting our lands, our heritage, our wildlife and our environment. We can build that climate for investment," Murkowski said. ●

Contact Alan Bailey at abailey@petroleumnews.com

● EXPLORATION & PRODUCTION

Contender in oil sands stakes

MEG Energy shrugs off disappointments of IPO with strong showing in 1st year of operation, spurring on plans for 2 major projects

By GARY PARK

For Petroleum News

MEG Energy, having stumbled out of the starting gates as Canada's newest publicly traded oil sands company, is now in full stride.

The startup has made what it somewhat immodestly claims to be the "fastest, most efficient" beginning of any in-situ project. And, so far, no one is taking issue.

MEG (which has state-owned China National Offshore Oil Corp. as a 16.69 percent partner) has reported glowing results from the first year of commercial operation at its Christina Lake project in northern Alberta by exceeding design capacity.

Company Chairman Bill McCaffery said that as a result MEG is setting its sights on more than doubling production to 60,000 barrels per day, coming onstream in 2013, and is entering the regulatory process with its planned 100,000 bpd Surmont project, expected to start production in 2018.

Backed by estimates from GLJ Petroleum Consultants, an independent reservoir engineering firm, that its leases contain about 1.7 billion barrels of proved and probable bitumen reserves and 3.7 billion barrels of contingent resources, MEG is more certain than ever that it can ultimately achieve combined output of 260,000 bpd over 30 years.

Analyst says data supports MEG

Chris Feltin, an analyst with Macquarie Securities, said the public information available from the first year of production at Christina Lake support MEG's view that it has made the fastest startup in the in-situ sector, currently about 26,000 bpd.

Just to round out its solid underpinnings, MEG has growth properties west of Christina Lake and Surmont, covering 471,000 acres of 100 percent owned leases, with several large contiguous blocks the company believes could support standalone commercial enhanced oil recovery operations.

"They acquired their land early and got into a sweet spot in the overall trend with high reservoir quality," he said. "They've done a very efficient job in managing the steam injection rates and ramping up the project."

Using the steam-assisted gravity drainage technology, MEG injects steam into a horizontal well to melt the viscous heavy oil resource, which is then brought to the surface through a parallel well.

Thus the steam-to-oil ratio is a vital indicator of plant efficiency, measuring how much water and fuel must be used to recover each barrel of bitumen.

MEG produces steam at an 85 megawatt cogeneration power plant at Christina Lake, delivering 70 percent to the project and the rest into the Alberta power grid, with those revenues helping reduce operating costs.

MEG's Chief Financial Officer Dale Hohm said Christina Lake performed better than expected in the first half of 2010, with the per barrel steam-oil ratio and operating costs easing as production volumes rose.

The steam-oil-ratio dropped from 3.1 in the first quarter to 2.5 in the second quarter and 2.4 in May and June.

Operating costs, including the cost of gas consumed for cogeneration, plunged from C$39.01 per barrel in the first quarter to C$18.80 in the second and C$16.40 (C$10.42 for non-energy costs and C$5.98 per barrel of oil equivalent for gas) in June.

126,000 contiguous acres

Christina Lake sits on 126,000 contiguous acres, adjacent to Cenovus Energy's own Christina Lake project and northeast of Devon Canada's Jackfish project.

While ready to move ahead with construction of its second phase, MEG has filed a regulatory application for Phase 3, targeting staged development of 150,000 bpd, aiming to bring 50,000 bpd onstream in 2016 and two more additions of 50,000 bpd each in two- to three-year intervals.

The Surmont project is 30 miles north of Christina Lake and is adjacent to oil sands leases operated by ConocoPhillips Canada. GLJ has assigned combined proved and probable reserves and contingent resources of 647 million barrels to the lease.

A detailed environmental impact assessment has almost been completed and MEG expects to submit its regulatory proposal in 2011.

The IPO price came in at C$35 and has since slipped under C$32, partly due to the dismal performance of peer-company Athabasca Oil Sands, which raised C$1.35 billion in an IPO in February, but has since seen its market price slide from C$18 to under C$12.

Just to round out its solid underpinnings, MEG has growth properties west of Christina Lake and Surmont, covering 471,000 acres of 100 percent owned leases, with several large contiguous blocks the company believes could support standalone commercial enhanced oil recovery operations.

As well, MEG and Devon are joint owners of a 215-mile pipeline system between Christina Lake and the Edmonton area — including a 24-inch line to transport diluted bitumen to a blending and storage facility.

IPO scaled back

All this helps disperse the one blotch hanging over MEG, which scaled back its initial public offering, which started trading at the end of July, from C$1.1 billion to about C$700 million, cutting its share price to C$35-$39 from a hoped-for C$42-$48.

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While Athabasca left a bad taste in the mouths of oil sands investors, MEG has been undeterred, raising its 2010 capital budget to C$629 million from C$439 million in preparation for detailed engineering and major equipment purchases for the next phase of Christina Lake and the addition of new Surmont leases.

Hohm, based on a one-month road trip before the IPO, said the big question for MEG is how much of the company's future growth investors will pay for up front.

"Investors really like what the company is doing and they see the potential going forward, but they'd like to profit from it as well," he said.

Market uncertain for others

However, the market uncertainty has posed questions for other privately owned oil sands players eying IPOs.

The next potential candidates are:

• Laricina Energy, founded in 2005 and holding more than 180,000 acres and C$450 million of equity capital. Its major original shareholders were Warburg Pincus and The Blackstone Group. They were joined in July by the government's Canada Pension Plan Investment Board, which made a private placement of C$200 million to take a 17.1 percent equity stake.

• Grizzly Oil Sands, formed in 2006, with more than 500,000 acres of leases and permits. It is 75 percent owned by Wexford Capital and 25 percent by Oklahoma-based Gulfport Energy.

• Sunshine Oilsands, founded in 2007, with the purchase of four leases, to which it has gradually added. ●

Contact Gary Park through publisher@petroleumnews.com

● GOVERNMENT

Agency clarifies offshore review rules

By ELIZABETH BLUEMINK

Anchorage Daily News

A federal agency that regulates offshore oil and gas drilling in Alaska has clarified its rules this summer after a government audit said some of its Alaska employees were blocked from information that would help them assess environmental impacts.

The new directive was sent this summer to all 80 workers in the Alaska Region of the new Bureau of Ocean Energy Management, Regulation and Enforcement — the former Minerals Management Service. An agency spokesman said Aug. 16 that mandatory training sessions for the Alaska workers began earlier in August.

The directive, developed by the agency's regional managers, lists the rules for how their staff in Alaska must handle proprietary information received from oil and gas companies. The rules spell out everything from how the paperwork is color coded — with green lettering — to the steps workers should take if they've been denied access to information they need for their jobs.

The agency has overseen controversial federal lease sales for the Beaufort and Chukchi seas off Alaska's northern coast. Some exploration activities on those leases are on hold as the federal government reconsiders its offshore leasing in light of this year's massive Gulf of Mexico spill. The agency also is being sued by North Slope villages and environmental groups over the Beaufort and Chukchi lease sales.

The Alaska spokesman for BOEMRE and the head of a federal whistle-blower group concerned about the agency's handling of company data agreed that the new directive doesn't change much.

Audit found inconsistencies

The audit, published in April, said the Alaska office's actions were inconsistent with a 2008 federal policy requiring that the confidential documents from oil and gas companies be shared with analysts who make environmental assessments of drilling projects.

The agency has since pledged to comply with the policy, according to the Government Accountability Office, an investigative arm of Congress that issued the critical audit.

On Aug. 16, the Alaska spokesman for BOEMRE and the head of a federal whistle-blower group concerned about the agency's handling of company data agreed that the new directive doesn't change much.

"This directive clarifies procedures and ensures that everyone is following them. But it doesn't change the procedures," said John Callahan, a regional spokesman.

But the new directive doesn't allow the public or third-party experts to see the oil company data used to justify agency decisions, complained Jeff Ruch, head of the Public Employees for Environmental Responsibility, a government worker whistle-blower group.

Confidentiality required

Callahan responded that federal law requires the agency to keep certain corporate data secret. Also, the companies would not provide the information if the agency didn't keep it confidential, he added.

The audit charged that regional managers of the agency restricted their environmental analysts from reviewing the data.

The audit said the regional office managers offered the GAO some practical reasons for why they were restricting the flow of the information, such as the need to guard proprietary information.

But the audit noted some negative consequences from the lack of sharing. It said, for example, that five analysts reported difficulty getting a clear sense of the offshore projects they were tasked to review, including a proposed 2011 oil and gas lease sale in federal waters near Bristol Bay, a sale the Obama administration canceled this year.

The audit also recommended that the agency, at the national level, create a comprehensive handbook describing how its staff should comply with the National Environmental Policy Act, the federal law that requires agencies to conduct environmental assessments.

The agency said it is reviewing how it implements the law and plans to publish the handbook next year. ●

NATURAL GAS

CINGSA applies for storage authorization

Cook Inlet Natural Gas Storage Alaska has applied to the Alaska Oil and Gas Conservation Commission for authorization for underground storage of natural gas in the Cannery Loop unit on the Kenai Peninsula.

CINGSA, a joint venture of Semco Energy, the parent company of Southcentral gas utility Enstar Natural Gas Co., and MidAmerican Energy Holdings Co., proposes to build a gas storage facility, and to have the facility available for use by the summer of 2012 in order to avert forecast deliverability shortfalls in the winter of 2012-13.

The commission has tentatively scheduled a public hearing on the application for Oct. 19 at 9 a.m. at its Anchorage office.

If there are no requests for a hearing, the commission may issue an order without a hearing.

Written comments will be accepted through 4:30 p.m. Oct. 2; if a hearing is held, comments will also be accepted at the hearing.

The commission will determine by Sept. 21 whether a hearing will be held.

CINGSA previously filed with the Regulatory Commission of Alaska for a certificate of convenience and necessity.

—PETROLEUM NEWS

● NATURAL GAS

Economic impact of Marcellus is growing

By ERICA PETERSON
The Associated Press

Marcellus Shale drilling is still in its infancy in West Virginia, but the industry is already contributing millions of dollars to the state's economy. It may be awhile before the gas industry's economic impact rivals that of coal in West Virginia.

Mike Shaver, clad in a hard hat and muddy boots, surveys a gas drilling rig on a site in Upshur County. As a crew drills towards the Marcellus Shale, a pipe pumps water and dirt out of the hole in the earth and into a huge pit of muddy, rock-filled water. Shaver looks at the water, trying to determine how much farther the drill has to go before reaching shale gas.

Shaver is the owner of Mountain V Oil and Gas, based in Bridgeport. His company started drilling in the Marcellus Shale two years ago. He says the Marcellus hasn't changed his business — he's still drilling for gas, after all — but now things are done on a bigger scale. He drills fewer wells to get the same amount of gas, but they're deeper and more expensive to drill.

"Instead of drilling 60-100 conventional wells, we're looking at only drilling 15 Marcellus wells due to the cost," he said. "The production on the Marcellus has proven to be worth changing our business model. Basically, the way we're looking at it, it takes 10 conventional wells to equal the production of one Marcellus well, based on our results in Upshur County."

Drilling began in 2002

When gas drillers began tapping the West Virginia Marcellus Shale in 2002, only two wells were drilled. In 2008, that number had skyrocketed to 299, according to a report sponsored by the federal government. Though gas has been drilled in the state for years, with the Marcellus Shale the industry is booming.

But in West Virginia, the economic benefit of natural gas is still dwarfed by coal. The number of people directly employed by the coal industry has been declining for years, but production is at an all-time high, according to the West Virginia Coal Association. And high production means higher severance taxes for the state.

During the last fiscal year, the coal industry paid more than $379 million in severance taxes to the state, part of which is then distributed to counties. This is almost five times more than the amount paid in natural gas severance taxes during the same period.

But the gap is closing. The amount of money the state and counties get from natural gas severance taxes is increasing at more than twice the rate of coal severance taxes.

Coal's future uncertain

The rise of gas drilling in West Virginia also comes at a time when the future is more uncertain for the coal industry. Coal production is still increasing each year, but it's not expected to do as well if a national cap-and-trade policy is introduced. Bruce Biewald is president of Synapse Energy Economics, a Boston-area energy consulting firm.

"I think cap-and-trade heavily favors renewables and efficiency, with zero or low CO2 emissions and will tend to hurt coal," Biewald said. "For gas, it's kind of in the middle and in some cases it's hard to say which way things get pushed for gas."

In the face of possible future carbon regulations, some power companies are even shutting down their coal-fired power plants to make room for gas-fired ones.

In December, North Carolina-based Progress Energy announced that it would close 11 coal-fired units in the state and replacing them with natural gas. Progress spokesman Drew Elliot says it was a decision that made economic sense for the company.

"Well, we look at a lot of things when we talk about retiring old plants or building new ones. This was a big decision for us," he said. "We look at what are the reg-

see MARCELLUS SHALE page 11

GOVERNMENT

Deepwater 'categorical exemptions' halted

The Obama administration announced Aug. 16 that it is requiring environmental reviews for all new deepwater oil drilling.

The announcement came in response to a report by the White House Council on Environmental Quality, which found that decades-old data provided the basis for exempting BP's drilling permits from any extensive review.

The Interior Department said the ban on so-called "categorical exclusions" for deepwater drilling would be in place pending full review of how such exemptions are granted.

"Our decision-making must be fully informed by an understanding of the potential environmental consequences of federal actions permitting offshore oil and gas development," Interior Secretary Ken Salazar said in a statement.

Shallow-water drilling will also be subjected to stricter environmental scrutiny under the new policy.

The report by the Council on Environmental Quality report says that the exclusions BP operated under were written in 1981 and 1986. That was long before the boom in deepwater drilling that was propelled by the development of dramatic new technologies for reaching deep into the sea floor.

The report also finds other problems with how MMS applied environmental laws in reviewing the BP project. It notes, for example, that in assessing the likelihood of a major spill, MMS did not consider the example of the disastrous 1979 Ixtoc spill in the Gulf — simply because the spill was not in U.S. waters.

MMS' successor agency, the Bureau of Ocean Energy Management, Enforcement and Regulation, is agreeing to recommendations to try to improve gas and oil drilling oversight, including pushing for more time to review exploration plans, and performing more comprehensive site-specific environmental reviews.

—THE ASSOCIATED PRESS

GOVERNMENT

Industry reminded to report BOPE use

The Alaska Oil and Gas Conservation Commission put out an industry guidance bulletin Aug. 9, reminding industry to report all use of blowout prevention equipment to prevent the flow of fluids from a well.

The commission said the reporting requirement applies to drilling, completion and workover operations.

Use must be reported within 24 hours.

For details on information required and submission of that information see the notice on the commission's website at http://doa.alaska.gov/ogc/.

—PETROLEUM NEWS

ALTERNATIVE ENERGY

AEA board OKs Haida Energy hydro loan

The Alaska Energy Authority board of directors has approved a $9 million power project fund loan to Haida Energy Inc. to help finance a new 5 megawatt hydroelectric project at Reynolds Creek on Prince of Wales Island in southeast Alaska.

Haida Energy, a newly formed entity established by Haida Corp. and Alaska Power and Telephone Co. Inc., was formed to construct and own the new Reynolds Creek plant, which has a total project cost of $17.25 million.

Haida Energy, a newly formed entity established by Haida Corp. and Alaska Power and Telephone Co. Inc., was formed to construct and own the new Reynolds Creek plant, which has a total project cost of $17.25 million. State and federal grants totaling $5.34 million were previously approved, and Haida Corp. invested $4 million and will reduce its equity investment to $2.91 million through use of the loan approved Aug. 11.

AEA's power project fund provides loans to local utilities, local governments or independent power producers for the development or upgrade of electric power facilities, including conservation, bulk fuel storage and waste energy conservation.

AEA is a public corporation of the state; its purpose is to reduce the cost of energy in Alaska.

—PETROLEUM NEWS

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MARCELLUS SHALE

ulations around coal, coal ash, right now, what are they going to be in the future. We look at the availability of natural gas in the area, what's the availability in the future, among other issues and we came to the decision that what's best for our company and our customers is this move to natural gas."

This isn't to say that Progress is abandoning coal; Elliot estimates that coal still generates the bulk of the company's energy. And even in an energy economy that relies more heavily on renewable energy, Biewald says gas will mostly likely play a supporting role.

"Natural gas as we move out in that direction has an important role in the near-term as kind of bulk electric generating fuel," he said. "But moving forward it becomes much more of a premium electricity supply source that's kind of used for backing up the wind."

Coal cheaper

Steven Levine specializes in energy economics at the Brattle Group, a consulting firm. He says even a tax on carbon may not create an even playing field, because coal is so much cheaper than natural gas. And he thinks incentives for renewables could hurt natural gas production.

"And in the meantime, if you're in a very renewables-focused strategy in the next 5-10 years, your outcome might be such that what you're actually doing is backing out natural gas, but not necessarily backing out coal," Levine said. "So it's sort of a high-cost abatement strategy at that point for CO2 because you're not knocking out the primary contributor to CO2 emissions which is coal."

Charlie Burd, president of the Independent Oil and Gas Association of West Virginia, thinks coal and gas industries have a harmonious relationship in West Virginia. In a perfect world, he says, both will flourish.

"With the passage of any cap-and-trade legislation, these coal power plants are going to have to make a determination how they want to reduce their emissions, and they can do it in one of two ways," Burd said.

"One would be to add more control technologies to reduce their emissions. Or, to do it more cheaply, they could install natural gas, co-fire, like they have around the country in other applications and thus reduce their emissions. Coal, again, is very important to the state of West Virginia, as is natural gas. For us, that could be a real win-win situation."

According to a federal government report, there are expected to be about 900 Marcellus wells in West Virginia by the year 2020. ●

Petroleum news

Business Spotlight

Garness Engineering Group

Garness Engineering Group is an Alaska owned civil and environmental engineering firm that specializes in the design, inspection, operation and maintenance of water and wastewater treatment systems. The company's staff has more than 50 years of experience, providing packaged water and wastewater treatment systems to Alaska's mining and oil-field industries, ranging from the North Slope, to the Panhandle and to the end of the Aleutian Chain.

FORREST CRANE

Jeffrey A. Garness, P.E., M.S., President & Principal Engineer

Jeffrey A. Garness

An Alaska resident since 1969, Jeffrey A. Garness attended the University of Alaska, where he earned a bachelor's degree in civil engineering and a master's degree in Arctic engineering.

Since starting his business in 1990, Garness Engineering Group has grown into one of Alaska's premier engineering firms. Garness is an avid hunter, fisherman, private pilot, football fan and MMA fan. He has been married to his wife Lisa for 30 years and has three adult children.

John S. Goerner

John S. Goerner is Water Treatment IV and Water Distribution IV operator certified. To Goerner, water treatment is not just a career, but his life's passion. Prior to working for Garness, he spent 18 years with Anchorage Water & Wastewater Utility. When not working, Goerner enjoys photography, astronomy, reading, travel, computers and the culinary arts. A defining moment in Goerner's life was the birth of his daughter LeAnn, who currently attends college in Florida.

FORREST CRANE

John S. Goerner, Consultant, Senior Water Technician

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

Global Diving & Salvage welcomes Ferguson to team


JOHN FERGUSON

Global Diving & Salvage said Aug. 5 that it would like to welcome John Ferguson, business development manager, to its Offshore Support Division. Ferguson has more than 17 years of experience in the offshore and international oil and gas industry. He will be using his expertise to prepare for opening a Houston office as the general manager. His current responsibilities include expanding Global's commercial diving, ROV and environmental services within the Gulf of Mexico region and evaluating international market potential. Ferguson's training includes dive school at The Ocean Corp. in Houston and the U.S. Marine Corps in the 1st battalion 4th Marines in Desert Storm. He is the developer and chairman of the Injured Warriors Campaign to raise money and awareness for injured veterans. Additionally, his personal accomplishments include traveling overseas for the Rotary Club teaching young entrepreneurs the art of small business ownership and being nominated for the Small Business Man of the Year award in Kansas.

Crowley recognized for clean air commitment

COURTESY CROWLEY

Bill Metcalf, Crowley's director of engineering

Crowley Maritime Corp. said Aug. 5 that its efforts to significantly reduce carbon emissions at the Port of Los Angeles and the Port of Long Beach were recognized during the third annual San Pedro Bay Ports Clean Air Action Plan Air Quality luncheon. The Clean Air Award recognizes companies who make great strides to reduce pollutant emissions at both ports. Committee members from the ports, as well as representatives from several governmental agencies reviewed all nominations, before choosing Crowley for its Significant Early Action to Reduce Emissions Award. "Crowley is committed to environmental stewardship in all the communities it serves. Over the past several years, the company has been involved in several emissions and energy-saving initiatives in this region, including the installation of shore-side power and four tug engine repowers," said Bill Metcalf, Crowley's director of engineering. "Those initiatives will reduce carbon dioxide emissions by more than 486,180 pounds, particulate matter emissions by 3.24 tons and mono-nitrogen oxides by 109.52 tons this year alone."

Nabors announces Superior Well Services merger

Nabors Industries Ltd. said Aug. 9 that it has entered into a definitive merger agreement with Superior Well Services Inc., whereby Nabors will acquire Superior.

The agreement contemplates that Nabors will commence a tender offer for all outstanding shares of Superior common stock at $22.12 per share in cash in accordance with the merger agreement. The transaction is valued at approximately $900 million. "For some time now, we have evaluated integrating more service offerings into our business, particularly internationally. Although we expect this acquisition by itself to be significantly accretive to 2011 results, our major motivator was the opportunity to leverage this well respected franchise into a global force utilizing our extensive international footprint and resources," said Gene Isenberg, Nabors chairman and CEO. "Superior Well Services possesses one of the newest fleets in the industry with over 430,000 hydraulic fracturing horsepower. This high quality fleet is operated by a very capable, well managed organization that can quickly become a substantial unit of Nabors. This transaction also provides good value to the Superior Well Services stockholders as the offer price represents an attractive premium to the 30-day average closing stock price."

Editor's note: All of these news items — some in expanded form — will appear in the next Arctic Oil & Gas Directory, a full color magazine that serves as a marketing tool for Petroleum News' contracted advertisers. The next edition will be released in March.

GOVERNMENT

OCS injunction back in district court

The U.S. Court of Appeals for the 5th Circuit has bounced the injunction against the U.S. Department of Interior outer continental shelf deepwater drilling moratorium back into Louisiana District Court.

DOI originally imposed a deepwater OCS drilling moratorium as part of its response to the Gulf of Mexico Deepwater Horizon disaster. But the Louisiana District Court imposed the injunction on the moratorium, pending resolution of a moratorium appeal in district court. DOI subsequently appealed the injunction in the 5th Circuit court but later issued a new drilling moratorium. DOI then asked the 5th Circuit court to rule the appeal case as moot, since DOI had withdrawn the version of the moratorium under appeal when it issued the new moratorium.

Although both moratoriums apply to deepwater drilling, they do so by applying different rules defining the moratorium scope. Key legal issues are whether the terms of the second moratorium would justify the imposition of an injunction in the same way as the first, and whether DOI can sidestep the injunction by simply issuing a different moratorium.

In an Aug. 16 court order, a majority of a panel of three 5th Circuit judges remanded the case back to district court, saying that the 5th Circuit court has insufficient record to determine whether the appeal case is moot. The appeal court has instructed the district court to conduct a hearing to establish the necessary facts on the record for a court ruling. The district court has now set a deadline of Aug. 24 for briefs in the case and the 5th Circuit court has cancelled oral arguments originally set for Sept. 1.

One of the 5th Circuit judges dissented from the majority opinion, saying that he thinks that the court has sufficient information on the record to make a ruling.

—ALAN BAILEY

LAND & LEASING

Potential Alaska state and federal oil and gas lease sales

Agency	Sale and Area	Proposed Date
DNR	Beaufort Sea Areawide	October 2010
DNR	North Slope Areawide	October 2010
DNR	North Slope Foothills Areawide	October 2010
DNR	Alaska Peninsula Areawide	May 2011
DNR	Cook Inlet Areawide	May 2011
DNR	Beaufort Sea Areawide	October 2011
DNR	North Slope Areawide	October 2011
DNR	North Slope Foothills Areawide	October 2011
MMS	Sale 211 Cook Inlet	2010*
MMS	Sale 219 Cook Inlet	2011*

Agency key: BLM, U.S. Department of the Interior's Bureau of Land Management, manages leasing in the National Petroleum Reserve-Alaska; DNR, Alaska Department of Natural Resources, Division of Oil and Gas, manages state oil and gas lease sales onshore and in state waters; MHT, Alaska Mental Health Trust Land Office, manages sales on trust lands; MMS, U.S. Department of the Interior's Minerals Management Service, Alaska region outer continental shelf office, manages sales in federal waters offshore Alaska.

**The OCS Cook Inlet sales are subject to industry interest. All other remaining Alaska sales on the 2007-12 schedule were cancelled.*

continued from page 1

COSMO OIL

and other petroleum products around the state, including Southeast Alaska, Western Alaska and Dutch Harbor, one of the nation's top commercial fishing ports.

Jet fuel crunch

The potential arrival of new supplies of jet fuel comes as welcome relief to the air cargo industry, which uses Ted Stevens Anchorage International Airport as a major fueling and package-sorting stop on flights between Asia and North America.

Earlier this summer, state officials grew anxious when as many as 25 wide-body cargo jets per week were simply flying over Anchorage rather than stopping due to lack of jet fuel availability. Typically, the Anchorage airport sees some 600 landings of big cargo jets per week.

Such overflights are expensive for air carriers, who must displace revenue-generating cargo to carry more fuel, as well as Alaska's airport system, which was on track to lose $1 million a year in revenue.

Two key factors play into the jet fuel shortage.

First, the state long has grappled with a shortage of in-state fuel production relative to the huge and somewhat seasonal need at the Anchorage airport. The state has four refineries that can make jet fuel — the Flint Hills Resources refinery at North Pole near Fairbanks, the Tesoro refinery at Nikiski, and two Petro Star Inc. refineries at North Pole and in Valdez.

The Petro Star refineries supply jet fuel to the military, while the Tesoro refinery can produce only limited amounts of jet fuel as part of its production mix.

The big jet fuel producer is Flint Hills, which sends its output by train to Anchorage. Flint Hills production, however, has been irregular as the company struggles to make the plant economic. Coming into the summer, Flint Hills reactivated a third crude oil processing unit to help alleviate what could have been an even worse jet fuel crunch.

The second factor driving the jet fuel shortage has been a strong and welcome rebound in air cargo traffic through the Anchorage airport as the recession eases, airport managers say. This was a factor in Flint Hills bumping up its production.

But a worry is that Flint Hills will move to partially shut down its refinery this fall to avoid having to do the job in bitter cold conditions.

This raised the specter of jet fuel shortages during the peak season for the air cargo business, October through November, as shipments rise for the holidays.

Who is Cosmo?

The arrival of Cosmo and Delta Western on the scene could help fill the supply gap just at the right time. Having fuel available is key to keeping Anchorage among the top air cargo hubs in the world.

"That could fall off in a heartbeat if we don't have reliable fuel," said Jim Hemsath, deputy director at the Alaska Industrial Development and Export Authority.

Anchorage faces competition as an air cargo stop from Vancouver, British Columbia, and Seattle.

Jet fuel shipments into the Port of Anchorage, even from foreign sources, are not all that unusual, state officials say. It happens.

But Cosmo is a new entrant into Alaska, its C-plan application indicates.

Cosmo is one of Japan's top oil refiners and a major petroleum distributor, the Hoover's business information service says. It imports crude oil from the Middle East, runs four refineries and markets its goods through some 3,800 gas stations.

According to its application, Cosmo plans to operate double-hulled, spot charter tankers between Sakai, Japan, where the company has a refinery, and Anchorage.

It aims to transport up to 300,000 barrels of Jet A aviation fuel on a monthly or quarterly basis, depending on market demand at the Anchorage airport.

The fuel will be off-loaded at the Port of Anchorage, where it "will be stored and distributed by others," the Cosmo

see **COSMO OIL** *page 15*

continued from page 1

COHOE WELL

"We think it makes more sense to unitize the acreage and shoot 3-D seismic," Pfoff said. "However, as an alternative we are seeking the necessary permits to conduct a re-entry."

Pfoff said that Aurora had just finished a workover and recompletion of its Moquawkie No. 4 gas well and planned to start testing that well "within the next day or two." Moquawkie is one of five gas fields that Aurora operates on the west side of Cook Inlet.

Aurora does not yet have any approvals for drilling rig operations after the Moquawkie well but plans to use a coiled tubing unit to clean out several wells. The company is also busy with maintenance projects on its surface facilities, Pfoff said.

Drilled in 1973

Unocal drilled the Cohoe well in 1973 about four miles northeast of the community of Kasilof to a vertical depth of 15,680 feet in an unsuccessful search for oil. In a classic "bypass play," Aurora plans to determine if there are viable gas resources in rock horizons at some height above the original deep oil prospect.

"Like so many other wells drilled in the Cook Inlet, this well was drilled deeper, looking for oil and with heavier (drilling) mud," Pfoff said. "We see evidence of bypassed gas pay, but testing was minimal and we suspect negatively impacted by mud invasion into the formation."

The Cohoe well is relatively close to the existing Kenai Peninsula natural gas infrastructure, including the Kenai Kachemak pipeline, the line that any gas production from Cohoe would likely hook into.

Aurora says that it will use its AWS No. 1 drilling rig for the Cohoe re-entry, operating from the well's exiting gravel pad and starting the drilling operation on Sept. 15, depending on rig availability. There are existing gravel roads for access to the pad, Aurora said in its plan of operation.

The rig will drill down through some of the old cement plugs in the well before perforating the well casing to test for gas in the Beluga, Tyonek and Sterling gas sands, at depths ranging from 8,241 feet to 4,922 feet.

"The well is considered to be a development well because the well was logged during drilling and identified several gas targets," Aurora said in its plan of operations. "2-D seismic has been reprocessed to delineate several gas reservoirs."

ACMP consistency

In its plan, Aurora asserted that because it would simply be re-entering an existing well in an operation similar to a well rework, at a location some distance from the coast, a review for consistency under the Alaska Coastal Management Program would not be necessary.

But DNR appears to have taken different position on this issue. In an Aug. 17 letter to Aurora Gas, Alaska's Division of Coastal and Ocean Management told the company that the Division of Oil and Gas would coordinate an ACMP consistency review. And on the same day DNR issued a notice, inviting public comments on ACMP consistency by Sept. 15.

—ALAN BAILEY

Contact Alan Bailey
at abailey@petroleumnews.com

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CNG

when buying vehicles and equipment.

The study will look at existing CNG programs in North America to gauge the pros and cons from an environmental, economic and technical standpoint of using CNG in Alaska.

Some of those issues are obvious.

As a state with few highways, a limited number of filling stations in Alaska could service a large percentage of state and municipal vehicles. Many of the isolated villages around the state, though, would need their own stations to serve fleets of only a few vehicles.

While natural gas could have environmental benefits compared to diesel and gasoline, natural gas supplies in Alaska are currently stretched by residential and commercial use, electric generation and liquefied natural gas exports. However, the large and stable demand offered by state vehicles could help justify a pipeline from the North Slope, one possible solution for replacing the diminishing natural gas reserves in Cook Inlet.

Also, getting CNG to rural villages would in many ways replicate the transportation network that significantly drives up the price of fuels currently used for state vehicles.

Because CNG could make a major dent in domestic oil consumption, by taking cars off of gasoline, the federal government has devoted some resources to the technology, including financial models to gauge whether specific projects make business sense.

A focus on CNG in Utah

While the study will look at all public programs across North America, the request for proposals issued by the state on Aug. 10 specifically mentions a new program in Utah.

Utah currently offers several tax credits, grants and loans for people who buy CNG or other alternative fuel vehicles or convert existing vehicles to run on alternative fuels. The state also allows those vehicles to use high-occupancy vehicle lanes regardless of the number of passengers in the car. Salt Lake City offers free parking for alternative fuel vehicles, like CNG.

More relevant for the Alaska study, though, Utah runs a network of CNG fueling stations for public fleets and even allows private citizens to buy CNG in certain situations.

Utah is not alone, either. Several western states have networks of CNG fueling stations.

Not a new idea in Alaska

The proposed study is not the first to look at CNG as a solution to Alaska's energy woes.

Earlier in the year, the engineering firm PDC Harris Group publicly pitched the idea of shipping liquefied natural gas to rural communities around the state and compressing it for use in furnaces, boilers and small power plants currently running on diesel and fuel oil.

Bethel, a major rural hub in Southwest Alaska, later presented a similar idea to a state legislative committee, looking for some financing to push the project forward.

CNG is also not the only alternative floating around for fueling Alaska vehicles.

Alaska Electric Light & Power, the Juneau electric utility, is developing a pilot project for electric cars in the state's capitol. The utility believes that low-cost hydroelectricity combined with an isolated community where drive times are short could make it work.

—ERIC LIDJI

Contact Eric Lidji
at ericlidji@mac.com

FINANCE & ECONOMY

BP may use drilling money as collateral

The $20 billion victims' compensation fund established for the Gulf of Mexico oil spill may use revenue from BP's oil and gas drilling as collateral, according to details released Aug. 11 by the White House.

The government watchdog group Public Citizen criticized the arrangement as a conflict of interest, arguing that it gives the government a financial incentive to encourage BP to keep drilling offshore.

BP already has made a $3 billion initial deposit, announced Aug. 9. The company must pay $2 billion more this year and continue in installments of $1.25 billion, according to the trust documents released Aug. 11.

The trust sets up a collateral fund to ensure that all the necessary money will be available if something happens to the BP subsidiary that established the trust. Details still must be negotiated, but the trust documents say that unless a different agreement is reached, BP will agree to give the trust first priority to production payments from the company's U.S. oil and gas production as collateral.

Tyson Slocum, director of Public Citizen's energy program, said that securing the compensation fund with drilling revenue "is wildly inappropriate, as it will make the government and BP virtual partners in Gulf oil production. ... It will give the government a financial incentive to become an even bigger booster of offshore oil drilling in the Gulf."

The trust fund was negotiated by the Justice Department. A department spokeswoman did not immediately return a call for comment.

The trust is to be administered by two independent trustees, with claims being processed by Kenneth Feinberg, the Obama administration's pay czar.

—THE ASSOCIATED PRESS

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ROLLBACK

The spring royalty changes lowered the top crude royalty rate to 40 percent from 50 percent, locked in an initial 5 percent rate and dangled new incentives for deep and complex wells.

Second-quarter results show PetroBakken has increased the value of its wells in the sizzling Cardium play by 20 percent, and persuaded the company to shift some spending back to Alberta, which will claim 35 percent of the company's spending this year, compared with 10 percent last year.

PetroBakken President Gregg Smith said the royalty rollback is putting Alberta "back to work. … By making the changes, the pie is actually getting bigger." ●

Contact Gary Park through publisher@petroleumnews.com

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COSMO OIL

application says.

Neither Cosmo nor any of its subsidiaries have ever operated in Alaska state waters, it says.

The Anchorage office of Entrix, an environmental and natural resource management consulting firm, prepared Cosmo's C-plan.

'The good news'

John Parrott, manager of the Anchorage airport, told Petroleum News the West Coast is a net importer of jet fuel, so supplies from that region aren't always available for shipment to Anchorage.

"The good news is that cargo traffic is coming back up at the airport," he said. "I'm glad to know that it appears we will be able to maintain a stable fuel supply."

The fuel crunch, and the overflights, have been the subject of considerable concern this year, with the Alaska Senate Transportation Committee holding a hearing on June 29 and various industry players, state officials and others holding a May 21 meeting to talk about the supply issue.

Minutes from that meeting indicate that airport fuel needs for 2010 could average 56,000 barrels per day, peaking at 64,000.

"Part of the problem is that the carrier demand is not in sync with the refinery production curves," the minutes said.

Three companies were mentioned at the meeting as potentially interested in obtaining the necessary C-plan approval for hauling fuel to Anchorage: Cosmo, Delta Western and Morgan Stanley. ●

Contact Wesley Loy at wloy@petroleumnews.com

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COOK INLET GEOLOGY

providing public domain information of help to explorers who seek new oil and gas resources. Funding for the research has come from the state and from the oil industry.

And, in parallel with the DGGS work, the U.S. Geological Survey plans to conduct a new oil and gas assessment of the Cook Inlet basin in early 2011.

Rationale

A newly revised prospectus for the DGGS Cook Inlet project explains some of the rationale behind what the DGGS-led team is trying to achieve.

The aging Cook Inlet oil and gas fields occur in porous and permeable reservoirs in large, easily found geologic structures and represent the "low hanging fruit," picked early in the Cook Inlet basin's commercial history, the report says.

But, as oil and gas have percolated their way from petroleum sources through the tens of thousands of feet of rock strata in the basin, there could have been many less obvious locations where petroleum resources could have become trapped, perhaps for example in ancient river channels meandering their way through the subsurface or in the sands bodies left behind by ancient river fan structures — the Tertiary rocks that host all of the producing oil and gas fields are known to have been laid down on land from ancient river systems.

These relatively small, subtle oil and gas traps, known in geologic parlance as "stratigraphic traps," are much more difficult to find than the big structures of the low hanging fruit but could reservoir substantial undiscovered oil and gas resources. In addition, some gas could have become trapped in what are called "tight sands," where a lack of permeability within sand units has prevented the gas from escaping.

Through geologic fieldwork and associated investigations, the DGGS-led team wants to help oil and gas explorers by addressing questions such as whether the configuration of likely stratigraphic traps would lead to relatively low-volume reservoirs, and where within the basin stratigraphic traps are most likely to be found. Other questions being addressed are the extent to which well logs and seismic data can help people find the assemblages of rocks likely to contain stratigraphic traps, where within the basin tight gas sands might be found and the extent to which chemical alteration of the rocks or the presence of pore-clogging clays might detract from oil and gas reservoir quality.

Two areas

Since the Cook Inlet research program began in 2006, investigation of the Tertiary strata of the basin has focused on two areas where Tertiary rocks are well exposed at the surface: the Homer-Clam Gulch area on the southwest coast of the Kenai Peninsula, and the Capps Glacier area, tucked against the Alaska Range on the northwest side of the basin.

The work in the Homer-Clam Gulch area has enabled the recognition of several different styles of ancient river-sand deposition, while structures within the sands suggest upheavals caused by ancient earthquakes. In the Capps Glacier area, thick rock units containing masses of pebbles and boulders, with much of this detritus consisting of volcanic material, indicate the operation millions of years ago of torrential rivers flowing into the margin of the basin from volcanic peaks to the immediate west.

The team completed more than 400 square miles of geologic mapping in the Capps Glacier area in 2009, clarifying some aspects of the rock stratigraphy and assessing the impact of major geologic

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COOK INLET GEOLOGY

faults on the deposition of the rocks.

And as the research continues moving forward in 2010, the research team is piecing together the evidence for changes in rock types between the margins of the basin and the basin interior, and how these changes impact oil and gas reservoir characteristics. Geoscientists in the team are also using rock samples to assess how the origination of the sand grains in potential reservoir sandstones influences the chemical alteration of the grains, and hence the reservoir quality.

Another line of research involves the use of available seismic and well data to track Tertiary rock units through the subsurface, to develop maps of the subsurface geology and to determine the history of rock subsidence in different parts of the basin.

Mesozoic oil

As well as investigating the petroleum geology of the Tertiary strata that host the existing Cook Inlet oil and gas fields, the DGGS-led team is investigating the geology of the tens of thousands of feet of older Mesozoic rocks that underlie the Tertiary. The Jurassic Tuxedni group, within the Mesozoic rock sequence, is believed to have sourced most of the oil in the Cook Inlet oil fields, the oil having presumably percolated upwards into the Tertiary reservoirs.

And the question of whether to drill into the Mesozoic to seek new oil fields has perplexed Cook Inlet oil explorers for many years, especially given the very high cost and high uncertainty of drilling into this deep section of the basin. In the 2010 legislative session, Alaska lawmakers passed a bill that included a $25 million tax incentive for the next Cook Inlet Mesozoic oil exploration well.

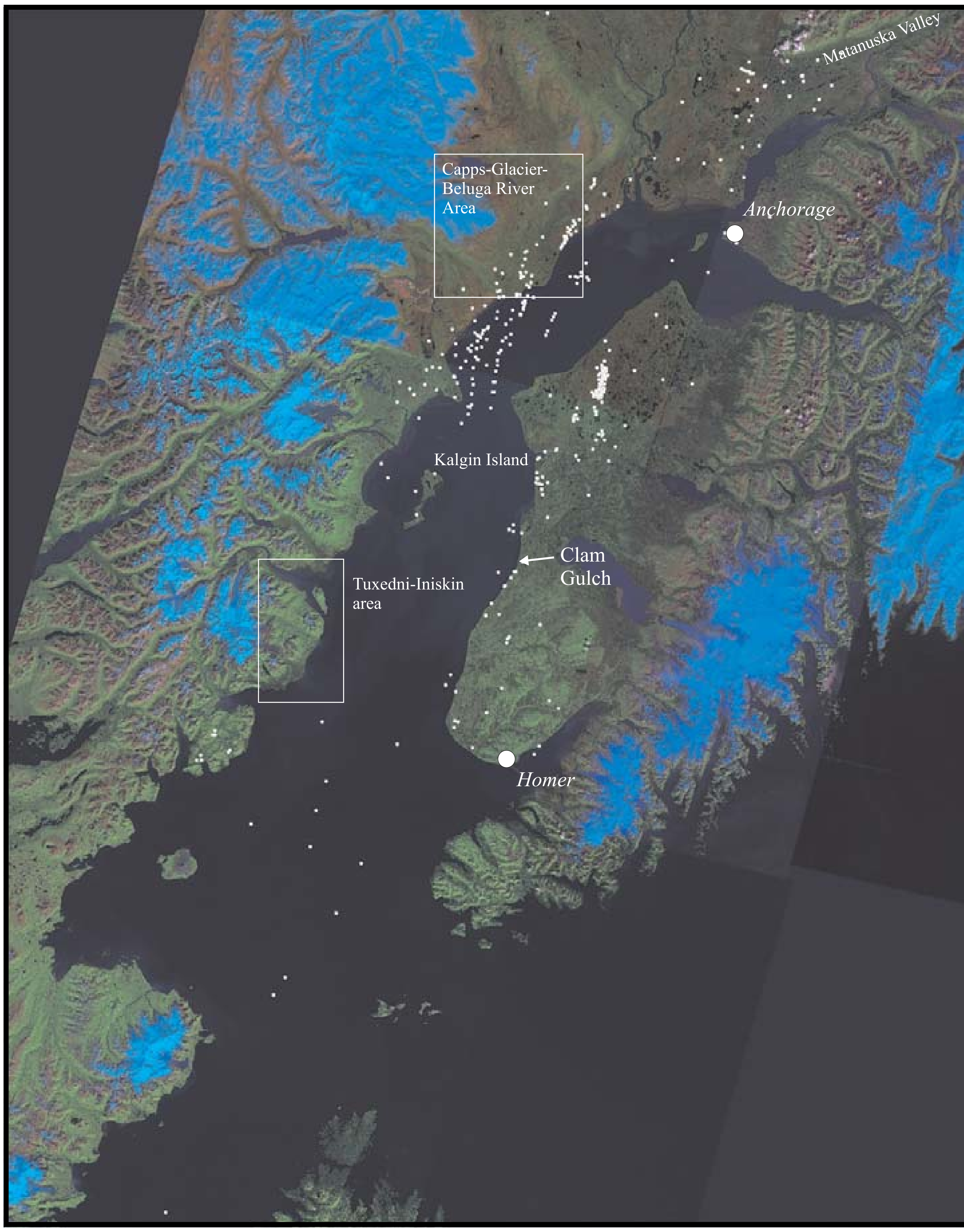
The DGGS-led team has been investigating excellent surface exposures of Mesozoic rocks on the west coast of Cook Inlet, between the Iniskin Peninsula and Tuxedni Bay, measuring rock sequences, taking rock and fossil samples, and assessing the geologic processes whereby the rock sequences were laid down.

Within the Mesozoic, there are Cretaceous sandstones that have good reservoir characteristics, but well penetrations into deeper and older rocks have found sandstones that tend to be clogged by minerals formed from the chemical alteration of sand grains. A prime objective of the DGGS research is to determine whether there may be areas of pre-Cretaceous rocks where reservoir quality is better than has been found to date. The team also wants to learn more about the ways in which the Cretaceous rocks were deposited, to evaluate potential Cretaceous reservoir shapes and sizes.

Subsurface map

And a continuing research objective will be to use available well and seismic data to evaluate which Mesozoic rock units directly underlie the Tertiary rocks of the basin, and hence produce a subsurface Mesozoic map showing the juxtaposition of oil and gas source and reservoir rocks. The team is also investigating the timing of the chemical alteration and clogging of potential Mesozoic oil reservoirs — the question of whether the rocks would have been altered before or after oil could have migrated into them is one of the keys to understanding the Mesozoic oil potential of the basin. ●

Contact Alan Bailey at abailey@petroleumnews.com



ALASKA DEPARTMENT OF NATURAL RESOURCES, DIVISION OF GEOLOGICAL AND GEOPHYSICAL SURVEYS

The thin scattering of Cook Inlet oil and gas wells, shown as white dots on this satellite image of the inlet, indicates to many geologists that the Cook Inlet basin is underexplored. A team of geoscientists, led by Alaska's Division of Geological and Geophysical Surveys, is investigating the petroleum geology of the region. The team has been doing fieldwork in the area of the two boxes marked on the west side of the inlet, and along the coast between Homer and Clam Gulch.