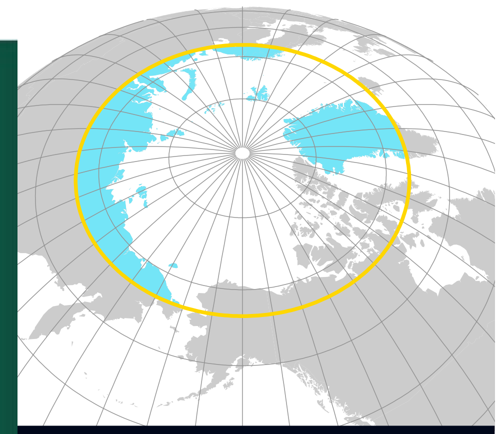
Petroleum news



page 10 Russia seeks international expertise, technology for remote areas

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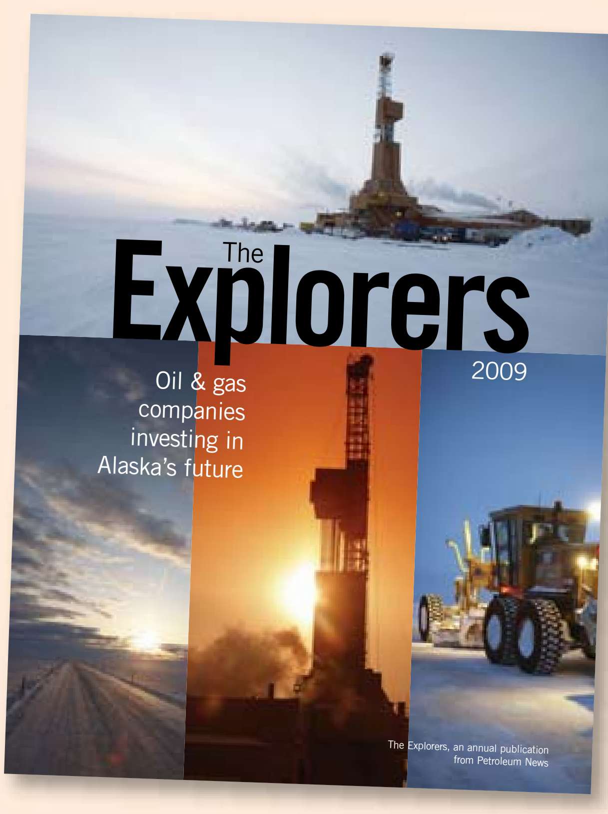
New twist for The Explorers 2009



Cover of The Explorers 2009 magazine. Cover photos taken by Judy Patrick.

Explorers magazine coming soon

Petroleum News' annual "The Explorers" magazine, which is first released at the Resource Development Council's conference in November, has a different format this year.

The Explorers 2009 is organized around regional exploration drilling in Alaska, with oil and gas company activities included in each region, along with geology and exploration and development history.

Oil company profiles are embedded in the region they are most active.

The final pages go to press Oct. 27.

For more information on The Explorers 2009 magazine, contact Marti Reeve, Petroleum News special publications director, at mreeve@petroleumnews.com, or Susan Crane, advertising director, at scrane@petroleumnews.com.

—PETROLEUM NEWS

Final arguments on Mackenzie gas pipeline set for April

Canada's National Energy Board said Oct. 7 that it expects to hear final arguments on the proposed C$16 billion Mackenzie pipeline in April, concluding a process that began in 2006, following the 2004 applications of the individual members of the Mackenzie Gas Project consortium to build the line to bring natural gas from the Mackenzie Delta to market.

The April date, however, is "dependent upon the release of

see MAC LINE page 15

B R E A K I N G   N E W S

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9 Stevens cites 'Incentive climate:' Former senator says Alaska must unite to tout its natural resource potential to world industry

NATURAL GAS

Railbelt crossroads

Gas-dependent SC Alaska tries to determine how to meet energy needs

By ALAN BAILEY

Petroleum News

As the Municipality of Anchorage prepares for the possibility of natural gas shortages during the cold of the coming winter, shortages that would cause the electric utilities to activate contingency plans for reduced gas usage and that might ultimately lead to rolling power blackouts, people may be shocked that a state rich in fossil fuel resources is struggling to meet the energy needs of its own inhabitants.

In fact, the whole Alaska Railbelt, including the City of Fairbanks far to the north of Alaska, to some extent shares an energy destiny united by an interlinked electricity grid; power generation

see CROSSROADS page 18

Wanted: Operator for Cook Inlet fields

The State of Alaska is looking for a contractor to come up with a longer-term solution for the Cook Inlet basin assets abandoned in bankruptcy proceedings by operator Pacific Energy Resources. Among those contacted by the state for a proposal was Gary Carlson, the former top executive for Forest Oil in Alaska, and executives with companies such as Ramshorn, Armstrong and Fairweather.

Two contractors, Peak Oilfield Service and Chumley's, have begun winterizing the wells at the West McArthur River oil field and the West

see WANTED page 19

FINANCE & ECONOMY

Credits survive mergers

State tax credit certificates don't go bad if oil explorer merges with another

By WESLEY LOY

For Petroleum News

State tax credit certificates don't go bad just because an oil and gas explorer merges with or sells to another company.

That's the upshot of an "advisory bulletin" the Alaska Department of Revenue's Tax Division issued Sept. 23.

The advisory says a company that absorbs or acquires another firm holding tax credit certificates, which the state awards to encourage exploration spending, can cash in those certificates with the state provided certain rules are followed.

The state issued the three-page advisory after "a

The state Tax Division has done half a dozen such advisory bulletins since the office gained authority to do them under Alaska's Clear and Equitable Share, the oil production tax reform the Legislature passed in late 2007.

business in Alaska" requested it. State officials held the name of the business confidential.

The advisory bulletin sketches out a couple of scenarios involving three firms, one of which is described as an "independent explorer" holding tax

see MERGERS page 17

EXPLORATION & PRODUCTION

Picking the test site

Researchers study potential areas for North Slope gas hydrate production test

By ALAN BAILEY

Petroleum News

Researchers engaged in a multiyear joint government, industry and university project to investigate the production of natural gas from gas hydrates under Alaska's central North Slope are selecting a site for a long-term production test. And drilling from the Prudhoe Bay field L pad into some nearby stacked, hydrate-filled sands seems the most likely scenario for setting up the test environment, said Tim Collett of the U.S. Geological Survey and Ray Boswell of the U.S. Department of Energy in the latest edition of the DOE "Fire in the Ice" newsletter.

And, while the site evaluation progresses, DOE and BP are forming an Alaska North Slope joint

But the path toward moving some of the known gas hydrate deposits into an "economically recoverable" status requires, among other things, a demonstration that effective gas production from the hydrates can be sustained over long periods of time.

industry project, to seek broader participation in the gas hydrate research, Collett and Boswell said.

In a parallel project, ConocoPhillips is working with DOE to plan a test of gas hydrate production by injecting waste carbon dioxide into hydrate deposits.

see HYDRATES page 15

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

● NATURAL GAS

Enstar fights to keep laundry overbilling snafu in tariff

State, gas suppliers, politicians, ratepayers tell RCA company shouldn't be able to recover $5.7 million

By KRISTEN NELSON
Petroleum News

The battle continues over who should bear the burden of Enstar Natural Gas Co.'s $5.7 million overbilling of the U.S. Department of Defense for natural gas deliveries.

For several years Enstar's billing system incorrectly indicated that measurement from a single meter was in hundreds of cubic feet rather than the correct thousands of cubic feet and gas volumes from that meter were billed at 10 times the actual rate of usage.

Enstar, the Southcentral Alaska local gas distribution company, has included the reimbursement it paid to the department in its tariff and customers are paying it as part of monthly gas bills. Approval of Enstar's tariff — including the $5.7 million — is before the Regulatory Commission of Alaska.

Enstar argued in filings with the RCA that its customers got the benefit of reduced natural gas costs when it won a settlement in an unrelated court suit. The reverse, Enstar said, is that customers should pay the amount Enstar had to pay Defense for the utility's overbilling for natural gas delivered to the department.

Enstar also argued that the natural gas was used by other customers and those other customers should pay for the gas.

Alaska legislators have joined the fray. Sen. Bill Wielechowski, D-Anchorage, said in a statement that RCA should reject Enstar's "request to add $5.7 million to the heating bills of Southcentral households and businesses this coming year to compensate for an error it made from 2002 to 2007."

He called Enstar's request "outrageous."

"Why is Enstar asking all customers to pay for a mistake it made in overbilling one customer?" Wielechowski asked. "There is no claim that gas meters in people's homes and businesses were inaccurately recording how much gas was being consumed, so how can Enstar come back now and say consumers used more than their meters recorded back then?"

Rep. Pete Petersen, D-Anchorage, said that as a small businessman he knows how important it is for businesses to take responsibility for their actions.

"Enstar made a mistake, and I do not believe that their customers should have to pay for it," he said in a statement, adding that he will monitor RCA's decision and if the commission "rules that under current law Enstar is allowed to pass these charges on to consumers I will introduce legislation to prevent this from happening in the future."

"Thanks to Enstar, our local natural gas company, for reminding us why it needs to be regulated," Rep. Les Gara, D-Anchorage, said in an e-mail to constituents.

Gara said that if Enstar gets its way, it will mean some $30 added to consumers' natural gas bills this year.

"They're billing you now, and retroactively seeking legal permission for it" from RCA, he said.

The RCA took public testimony Oct. 5 and heard arguments from Enstar and other parties Oct. 6-7.

Enstar failed to properly calculate natural gas usage at the Fort Richardson laundry, the state said, "causing its gas transportation customers … to supply ten times as much gas as was being consumed by" the Department of Defense.

What does the state say?

The state said RCA's regulations do not support Enstar's request to recover "through prospective rate increases" the cost associated with natural gas sales dating back to October 2004.

Enstar failed to properly calculate natural gas usage at the Fort Richardson laundry, the state said, "causing its gas transportation customers … to supply ten times as much gas as was being consumed by" the Department of Defense.

"Enstar reportedly used the volumes associated with (Department of Defense) mistaken consumption to meet its own system needs, but did not discover what had occurred nor settle up with the affected parties until recently, years after the gas had presumably been consumed by other Enstar customers," the state said.

In a filing with RCA the state said Enstar recently settled claims from the Department of Defense related to a large portion of the overpaid amount "and requests that current and future customers pay an additional $5.7 million in cost associated with gas sales to customers dating back to October 2004."

The state said it has no reason to dispute Enstar's assertion that the unit price of natural gas from Marathon and Aurora — gas oversupplied to Enstar by those producers and overbilled to the Department of Defense — was "lower than would otherwise have been available for purchase by Enstar during the relevant time period." The state also said the $5.7 million does not include more than $1.2 million worth of ConocoPhillips Alaska gas from Oct. 1, 2002, through Sept. 30, 2004, for which Enstar has yet to settle.

Gas cost adjustment not appropriate

The state said Enstar's proposal to recover costs through its gas cost adjustment is not appropriate because the gas cost adjustment in the utility's tariff provides for an annual submittal of changes in the cost of gas.

The gas cost adjustment also provides that cost elements in the adjustment must be "beyond the control of the utility," the state said.

"As discussed above, it is beyond dispute that Enstar was entirely accountable for the subject $5.7 million in gas costs not being properly and timely flowed through the GCA mechanism, starting as early as July 2002. Accordingly, it is untenable for Enstar to now pass on such costs to its 2009 and 2010 customers, regardless of when the cost was incurred," the state said.

While there may be some merit to Enstar's argument on the timing of qualifying events for the gas cost adjustment, the state said, "Enstar's analysis leapfrogs a threshold problem: The Commission's regulations do not support Enstar's request to recover those costs where their submission was not 'beyond the control of the utility.' In short, Enstar's gas costs in this case do not fall within the definition of the GCA regulations and thus are ineligible for recovery by that mechanism."

The state said that if Enstar had misplaced an invoice for gas purchases made in 2004-07 "the cost presumably would be excluded from consideration" under a current gas cost adjustment filing based

see **ENSTAR** page 14

● EXPLORATION & PRODUCTION

Alberta oil sands projects meet deadline

All operators have submitted tailings pond plans to the Energy Resources Conservation Board; fine particles must be reduced

PETROLEUM NEWS

All six Alberta oil sands tailings pond operators have submitted their plans to the Energy Resources Conservation Board, meeting a Sept. 30 deadline.

In an Oct. 1 press release ERCB said the deadline complies with Directive 074, which deals with tailings performance criteria and requirements for oil sands mining projects, requiring operators to prepare tailings plans and report on tailings ponds annually, reduce fine particles in liquid tailings by 20 percent by June 30, 2011, and by 50 percent by 2013.

Must be ready in 5 years

The land must be ready for reclamation five years after tailings are no longer being deposited in the ponds. Reclamation includes covering the sites with soil and planting trees, bushes and native grasses.

"Tailings" is a term used to describe waste from oil sands extraction processes. This waste, said ERCB, is "generally composed of water, sands, silt, clay and residual bitumen."

ERCB said its staff is conducting a "detailed and comprehensive technical review" of the tailings pond applications before it decides whether the plans comply with government requirements.

The six oil sands operators that filed the tailings pond plans were Canadian Natural Resources for its Horizons Oil Sands project; Imperial Oil Resources Ventures for its Kearl Oil Sands Project; Shell Canada for its Jackpine Mine and the Muskeg River Mine, which is actually run by Albian Sands Energy for a Shell joint venture; Fort Hills Energy for its Fort Hills Oil Sands Project; Syncrude for Mildred Lake, Aurora North and Aurora South; and Suncor Energy for its Millennium and Lease 86/17 tailings areas.

Suncor currently operates two extraction plants — Lease 86/17 Primary Extraction Plant, or Plant 3, and the Millennium Extraction Plant, or Plant 86.

Suncor's Steepbank Extraction Plant, or Plant 300, is in the process of being commissioned. The company expects it to be fully operational by the end of the year.

Suncor applied in June for an extension to keep Plant 3 operational until Plant 300 was up and running to facilitate the reclamation of the Lease 86/17 tailings ponds.

Imperial's Kearl Lake project is under construction, and Shell is planning an expansion of the Albian Muskeg River and Jackpine mine operations.

Technical review under way

ERCB said its staff is conducting a "detailed and comprehensive technical review" of the tailings pond applications before it decides whether the plans comply with government requirements.

Alberta's inventory of fluid fine tailings that require long-term containment is now 720 million cubic meters, the agency said.

Environmental groups are keeping a close eye on ERCB's review, arguing that oil sands development is creating an environmental catastrophe.

Recent attempts by Shell Canada to engage Greenpeace protestors in Canada in discussions have reportedly been ignored.

The submissions from the six operators have been scanned into digital format, and are posted on ERCB's Web site at www.ercb.ca. ●




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SAFETY & ENVIRONMENT

Mixed messages from Arctic sea ice data?

This summer's melt of Arctic sea ice resulted in the third lowest ice extent since satellite ice observations started in 1979, and a continuing prevalence of thin ice that is vulnerable to future melting. But a detailed analysis of this year's sea ice data shows some improved preservation of multiyear ice, according to an Oct. 6 report from the National Snow and Ice Data Center.

"We've preserved a fair amount of first-year ice and second-year ice after this summer compared to the past couple of years," said Walt Meier, an NSIDC scientist. "If this ice remains in the Arctic through the winter, it will thicken, which gives some hope of stabilizing the ice cover over the next few years. However, the ice is still much younger and thinner than it was in the 1980s, leaving it vulnerable to melt during the summer."

When the sea ice reached its minimum extent for this year, 49 percent of the ice was less than one year old and 32 percent was second-year ice, with the remaining 19 percent of the ice being older than two years. By comparison, in 2007 and 2008 the second-year ice only constituted 21 percent and 9 percent respectively of the ice cover.

Decline in thickness

But the minimum ice extent remains well below the average for 1979 to 2000. And researchers from the National Aeronautics and Space Administration have used satellite data to determine a decline in ice thickness of 2.2 feet between 2004 and 2008.

Sea surface temperatures in the Arctic during this year's melt season, although slightly lower than in the last two years, remained higher than normal. NSIDC attributes this year's cooler conditions to cloudy skies during the late summer.

And this year's increase in the ice extent is in part attributable to atmospheric conditions in August and September spreading out the ice pack, NSIDC said.

"It's nice to see a little recovery over the past couple years, but there's no reason to think that we're headed back to conditions seen back in the 1970s," said NSIDC Director and Senior Scientist Mark Serreze. "We still expect to see ice-free summers sometime in the next few decades."

—ALAN BAILEY

● EXPLORATION & PRODUCTION

September North Slope production up 18%

BP completes planned turnarounds for year with work at Northstar, where production returned to average rates in early October

By KRISTEN NELSON
Petroleum News

September Alaska North Slope production averaged 676,664 barrels per day, up 18 percent from an August average of 572,967 bpd.

The BP Exploration (Alaska)-operated Northstar field averaged 9,474 bpd in September, down 58 percent from an August average of 22,675 bpd, but returned to normal production levels in early October.

Planned turnaround work at Northstar — the last turnaround of the year on the North Slope — began in early September, BP Exploration (Alaska) spokesman Steve Rinehart told Petroleum News. The original work was completed as planned, he said, but during startup the need arose for some additional work; that work has been completed, he said Oct. 5.

The field averaged more than 20,000 bpd in early September. Production declined to fewer than 16,000 barrels Sept. 4 and for 10 days the field had no production. Northstar began moving oil again Sept. 15, but stayed below 16,000 bpd for the remainder of the month. By Oct. 3, however, production had topped 20,000 bpd at Northstar and was above 23,000 bpd the next few days, returning to production levels the field saw in August.

North Slope maintenance projects are frequently scheduled for the summer to coincide with planned turnarounds by Alyeska Pipeline Service Co. in the trans-Alaska oil pipeline and because of the weather.

It is easier and safer to do this planned maintenance in the warm months, Rinehart said: "Production is typically lower in the summer, so summer maintenance has the least impact on production, and people and equipment can be moved around more safely than in winter."

Prudhoe up 53%

Production from the BP-operated Prudhoe Bay field averaged 344,805 bpd in September, up 52.6 percent from an August average of 225,949 bpd. The largest month-over-month change at Prudhoe was completion of planned summer maintenance turnarounds at the field, where major work began in early June with 200 to 250 employees and contractors working through a series of maintenance projects including month-long projects at Gathering Center 2, Flow Station 2 and Gathering Center 1; and a two- to three-week project at Gathering Center 3 with work done primarily by people based at that facility.

On the Web

See previous Petroleum News coverage:

"Pipeline work brings ANS production down," in July 5, 2009, issue at www.petroleumnews.com/pnads/832188072.shtml

"Alyeska completes first summer shutdown," in June 28, 2009, issue at www.petroleumnews.com/pnads/441881793.shtml

"June sees first of summer turnarounds," in June 14, 2009, issue at www.petroleumnews.com/pnads/412168992.shtml

Prudhoe includes satellite production from Aurora, Borealis, Midnight Sun, Orion and Polaris.

The BP-operated Endicott field averaged 13,988 bpd in September, up 5.9 percent from an August average of 13,206 bpd.

Production from BP's Milne Point field averaged 28,739 bpd in September, up 5.4 percent from an August average of 27,277 bpd. Milne Point production includes Sag River and Schrader Bluff.

The ConocoPhillips Alaska-operated Kuparuk River field averaged 150,446 bpd in September, up 0.7 percent from an August average of 149,353. Kuparuk production includes Tabasco, Tarn, Meltwater and West Sak, as well as production from the Pioneer Natural Resources Alaska-operated Oooguruk field. Latest production by field records from the Alaska Oil and Gas Conservation Commission are for August and show Oooguruk production averaging some 8,654 bpd.

ConocoPhillips did maintenance at Kuparuk and Alpine this summer, with Alpine work scheduled in June and work at Kuparuk Central Processing Facility 2, which also began in June, completed July 23.

Alpine, Lisburne down

Two North Slope fields had drops in production from August to September, Alpine and Lisburne.

The BP-operated Lisburne field averaged 29,084 bpd in September, down 4.3 percent from an August average of 30,394 bpd.

The ConocoPhillips-operated Alpine field averaged 100,128 bpd in September, down 3.8 percent from an August average of 104,113 bpd. Alpine production includes satellites at Fiord, Nanuq and Qannik.

The temperature at Pump Station 1 on the North Slope averaged 36.8 degrees Fahrenheit in September compared to 45.8 F in August.

In Cook Inlet, production averaged 3,323 bpd in September, up 9.3 percent from an August average of 3,041 bpd, with production still down from previous levels of more than 10,000 bpd following closure of the Drift River Terminal due to volcanic activity at Mount Redoubt last spring. The most recent data by field from the Alaska Oil and Gas Conservation Commission shows some production from all Cook Inlet oil fields with the exception of Redoubt Shoal. ●

The most recent data by field from the Alaska Oil and Gas Conservation Commission shows some production from all Cook Inlet oil fields with the exception of Redoubt Shoal.

NATURAL GAS

RFP out for EIS for standalone line

The Alaska Department of Natural Resources has issued a request for proposals for preparation of an environmental impact statement for a standalone natural gas pipeline.

The contract will run from Nov. 10, the expected date of award of the contract, until completion, estimated at Dec. 31, 2010. DNR has the option to renew the contract once for an additional 12 months.

The selected contractor will work with the lead permitting agency (anticipated to be the U.S. Army Corps of Engineers), other participating agencies, DNR and an environmental support services contractor to prepare the EIS. The EIS contractor will not perform any of the environmental base line work.

Deliverables are due over a 15-month period from October through December 2010.

The budget for the work is estimated at $850,000 to $1.25 million; DNR said proposals priced at more than $1.25 million will be considered nonresponsive.

The EIS is required for DNR to evaluate and pursue a standalone gas pipeline which would transport natural gas from Prudhoe Bay to Southcentral Alaska, providing reliable gas supplies to Fairbanks, the Railbelt, the Anchorage area and others.

The two alternative routes to be included in the EIS are: Parks Highway, a 753-mile main line plus a 35-mile lateral to Fairbanks; and Richardson Highway, a 845-mile main line.

Assumptions to be used in preparing the EIS include: a buried pipeline; retention of existing public access routes; permanent work pad and access will be minimized; and no new permanent public vehicular access routes proposed.

—PETROLEUM NEWS

● EXPLORATION & PRODUCTION

Fiscal climate in eastern Canada calm

Area economy small, driven by large offshore projects; Repsol newest player; ConocoPhillips hunting rig, may face political issues

By WES REID
For Petroleum News

Eastern Canada is a region normally associated with high winds and high unemployment. Ironically, however, the fiscal climate there remains calm during this recession. In some parts of the region, real estate — often the canary of economic performance — is flying high. Bob Cadigan is president and CEO of the Newfoundland and Labrador Oil and Gas Industries Association. His organization represents nearly 500 companies servicing and supplying Eastern Canada's offshore petroleum industry.

1 2 SERIES

"We're not seeing any of the impacts in the St. John's area that people elsewhere in Canada are seeing," Cadigan said via telephone from his office in downtown St. John's. Newfoundland and Labrador's capital, it sits at the eastern end of the province facing Ireland. "Housing prices over the last several years have increased significantly — I think in the range of 30 percent — so supply is relatively short; houses are selling fairly quickly."

Region should have been rocked

The world financial crisis should have rocked the Rock (as Newfoundland and Labrador is known in Canada) and Nova Scotia. Their hydrocarbon sectors absorbed the shock and made times in the Maritimes and Newfoundland and Labrador easier than usual.

"It's a small economy," Cadigan explained. "By virtue of the fact there are large offshore projects we're dealing with, we haven't been seeing the kinds of impacts that you've been seeing in Alberta with the more marginal fields."

Lagging oil demand and the subsequent slump in its value, stretching between last fall and last spring, did create some anxiety among East Coast petroleum players. But crude's plummeting prices have resurged, shoring up the feasibility of searching offshore for commercially viable hydrocarbon deposits in Newfoundland and Labrador's Laurentian subbasin, Orphan basin, Jeanne d'Arc basin, Flemish Pass and Labrador Shelf as well as Nova Scotia's Scotian Shelf.

"In the last two years, the province has attracted more than $300 million in work commitments in the offshore through land sales," said Newfoundland and Labrador Natural Resources Minister Kathy Dunderdale. "The 2008 land sale attracted new and existing players to the offshore, demonstrating that industry continues to see the province's basins as prospective with a total of $132 million in work commitments this year alone."

Repsol new kid on block

The new hydrocarbon kid on the Rock's block that Dunderdale refers to is Spain-based Repsol. Operating worldwide, upstream and down, offshore and on, the petroleum firm partnered with Petro-Canada and Husky Energy to purchase three land blocks, two of them in the Central Ridge-Flemish Pass area, the other in the Jeanne d'Arc basin.

At the Central Ridge-Flemish Pass, Repsol controls 20 percent of one parcel. Petro-Canada and Husky each own 40 percent. The property comprises 138,200 hectares. It cost them $18.6 million. Husky and Repsol paid $1.19 million for 134,227 hectares constituting the other property in the Central Ridge-Flemish Pass.

On the Web

See previous Petroleum News coverage:

"Canada's offshore oil patch skirts storm," in Oct. 4, 2009, issue at www.petroleumnews.com/pnads/482606912.shtml

The Jeanne d'Arc parcel, at 121,348 hectares, went to Husky (67 percent) and Repsol (33 percent) for nearly $9.5 million.

Paul Barnes manages the Atlantic Canada branch of the Canadian Association of Petroleum Producers. He believes Repsol's purchases illustrate increasing global interest and possible further investment in Eastern Canada's oil patch.

"The importance of having Repsol actively looking for offshore oil here will help bring international recognition to the region," he said. "And if they meet success it will certainly help promote Atlantic Canada and bring more investment here."

Repsol recently disclosed that, with the help of IBM, it has devised a unique seismic imaging system. The company claims the technology can reduce exploration costs by almost 50 percent by spotting more quickly and accurately hydrocarbon reservoirs lying within seafloors. Analysts call the technology Project Kaleidoscope. Repsol may use it first on its Newfoundland and Labrador properties.

Dunderdale's department says 6 billion barrels of crude and 60 trillion cubic feet of natural gas "wait to be discovered" on Newfoundland and Labrador's Grand Banks. She believes people can bank on Repsol playing a bigger role in her jurisdiction's offshore exploration play.

"As a province and a government we are continually looking for opportunities to further advance our energy sector and, I think, our job is made easier by the fact that oil companies continue to have an interest in our highly prospective regions," Dunderdale said.

Laurentian subbasin

The Laurentian subbasin is one such region. Potentially containing 700 million barrels of recoverable crude and 10 tcf of natural gas, the 60,000-square-kilometer slab of deepwater seabed sits between southern Newfoundland and northern Nova Scotia. The Canada-Newfoundland and Labrador Offshore Petroleum Board has, since 2004, issued eight exploration licenses for the subbasin. Last June, during its 2009 Call for Bids, the board placed two more land blocks there on the auction block.

ConocoPhillips holds four of the licenses. In January, the company opened an office in St. John's. For more than a year, it has been attempting to lease a deepwater drill rig that can sink an exploration well into Laurentian subbasin geology lying beneath 2000 meters of ocean.

ConocoPhillips spokesman Rob Evans said the process has been difficult due to a general shortage of rigs, especially those fit for the area's frigid, storm-prone abyssal depths.

"This is very deep water," Evans said from his Calgary office. "There're not that many rigs available that can operate in that sort of environment. We've been talking to a lot of folks but we just haven't been able to sign on the dotted line yet."

Ian Way, vice president of strategic planning and business development for ConocoPhillips Canada, noted the firm may sublet a semisubmersible from another oil company.

"We need one that's capable of drilling in deep water and we're in conversation with someone about a possible sublet, but having to deal with the owner of the rig as well as the company it's under contract to right now it gets a little complicated," he said.

The Laurentian subbasin parcel grabbing most attention from ConocoPhillips has to be drilled by mid-2010. If not, the Canada-Newfoundland and Labrador Offshore Petroleum Board — managing and regulating Newfoundland and Labrador's offshore hydrocarbon play — could revoke the company's exploration licence for the property.

"The licences have an expiry of 2013, but there are different terms within those licences that require us to get a well down, I think, in about a year from now without reworking the terms within those licences with the C-NLOPB," Way said. "If you don't fulfill the terms of the licences then you would have to relinquish the acreage."

Deepwater expensive

A deepwater exploration well is an

see CLIMATE page 7

● SAFETY & ENVIRONMENT

Belugas on decline after 2 steady years

NOAA reports count of 321 of endangered whales in Cook Inlet this year; down from an estimated 375 in 2007 and 2008

By MARY PEMBERTON

Associated Press Writer

A government study found that a group of endangered beluga whales in Alaska is declining, raising concern that bolstered protection for the animals is not coming quickly enough.

The downward trend comes after two years when numbers for the Cook Inlet belugas appeared to have stabilized. But now numbers have slipped again to 321 animals, down from an estimated 375 in 2007 and 2008, according to figures released Oct. 6 by the National Oceanic and Atmospheric Administration.

The Cook Inlet whales, which swim mainly off Anchorage, are considered a genetically distinct population and don't mix with the other four beluga groups in Alaska.

The lower number in 2009 underscores the need for NOAA to act more aggressively to reverse the decline and save the whales from extinction, said Brendan Cummings, oceans program director with the Center for Biological Diversity, a group that has used legal pressure to try to get more protections for Cook Inlet belugas.

Cummings said one year after the listing there is no critical habitat designation and no recovery team or recovery plan in place. But, he said, it is not too late to save Cook Inlet's belugas if the federal agencies put their best efforts into protecting them and the state removes obstacles to their recovery.

"It has to start very soon or each year we will see fewer and fewer belugas until one day we will see no more at all," he said.

Proposal will be issued this month

Barbara Mahoney, a biologist with the National Marine Fisheries Service in Anchorage, said a critical habitat proposal will be issued this month and a recovery team is being put in place.

Scientists do not know why Cook Inlet belugas have declined. Overharvesting by Alaska Natives is believed to have contributed but numbers continued to decline even after hunting was sharply curtailed in 1999. There has been no subsistence hunt for the past three years. None is planned for the immediate future.

There were about 1,300 Cook Inlet belugas in the 1980s but numbers had declined to an estimated 653 in 1994. Numbers reached an all-time low of 278 in 2005. Alaska's other four beluga groups are not endangered and number in the thousands.

The Cook Inlet belugas were listed last year as endangered, a move that was opposed by the state over concerns about what a listing would do to the state's economy. Cook Inlet is an economic hub.

The federal listing requires the designation of critical habitat, a recovery plan and a review of activities in Cook Inlet.

Given the economic importance of Cook Inlet, Mahoney said the agency conducted an economic analysis, looking at such things as the expansion of the port, shipping, tourism, military installations, commercial fishing and oil and gas exploration.

Officials have said the listing does not mean that development in Cook Inlet will stop, only that it will have to undergo a more rigorous review. ●

continued from page 6

CLIMATE

expensive proposition. Chevron, estimating it would spend $140 million and four months in late 2006 boring a deepwater well dubbed Great Barasway F-66 at the Orphan basin, ended up coughing up more than $200 million during seven months working on the project. Rough weather, pack ice, and mechanical problems were blamed for most of the cost and time overruns. The company planned to spud a second exploration well in the Orphan basin during mid-2009. Unable yet to obtain a rig and realizing that hole might incur greater expense than their first, Chevron delayed the project.

"The cost estimates … that were coming in for the second well were coming in very high, in fact, higher than the cost estimates for the first well," said Mark MacLeod, Chevron's Atlantic Canada manager. The company continues searching for a rig, though, and remains confident in Eastern Canada's offshore oil patch. "We recognize that it's disappointing in the local community, but … it's important to say that we are very committed to the region," MacLeod said.

If Chevron's experience is any indication, ConocoPhillips may be underestimating its budget for the Laurentian subbasin.

"We're looking carefully at all of our investments around the world, with less free cash flow to invest in this particular project, but if we're able to secure a rig we're committed to try and test the prospect," Way said.

Political delays possible

Even if ConocoPhillips finds a rig it may still face delays this time of a political nature.

> *"The importance of having Repsol actively looking for offshore oil here will help bring international recognition to the region."*
> —Paul Barnes, manager of the Atlantic Canada branch of the Canadian Association of Petroleum Producers

Other oil companies hoping to lease land in the Laurentian subbasin may also experience setbacks.

On behalf of its 6,300 residents comprising the population of St. Pierre-et-Miquelon, France last May, petitioned the United Nations for extended rights to waters covering a swath of the Laurentian subbasin. France took a similar action in 1992. It lost to international arbitration. Given the right to appeal until May13, 2009, it seized the opportunity just before deadline.

Seeing Newfoundland and Labrador prosper and, last summer, gain status for the first time as a Canadian province primarily because of its robust petroleum sector, the people of St. Pierre-et-Miquelon want a piece of that black gold pie. But they and their Gallic cousins from across the Atlantic will be forced to slice it with a sword, according to a Maclean's Magazine article published in March.

"Canada will take all necessary measures to defend and protect its rights with respect to its continental shelf," Canadian Foreign Affairs Minister Lawrence Cannon was quoted in the story. Licensing could become tricky if the UN grants France greater territory off Newfoundland's south coast than it was originally given. Derisively named the Baguette (loaf of bread) by St. Pierre-et-Miquelon locals, it encompasses their two islands — sitting about 20 kilometers off the province — and extends 350 kilometers southward at a width of 2.5 kilometers into the North Atlantic.

That demarcation takes in an insignificant amount of the area potentially containing the hydrocarbons. Whatever the outcome, Way doesn't believe politics will affect Conoco-Phillips' drilling plans. "There doesn't appear to be an overlap with the licensing, so we don't believe we're going to be directly affected," he said.

StatoilHydro moving ahead

StatoilHydro won't have to worry about political squabbling or finding a rig for the well it expects to spud this summer. Foresight and cooperation put that firm, along with Husky Energy and Petro-Canada, in an envious position. Last year, the three pulled off a cost-sharing agreement to secure the semisubmersible oil rig Henry Goodrich. As part of that deal StatoilHydro in December drilled on its Mizzen land parcel nearly 500 kilometers east-northeast of St. John's. The property is situated in deep water at the Flemish Pass.

The spud was so encouraging that StatoilHydro and Husky Energy, its 35-percent partner in the venture, applied to the C-NLOPB for a significant discovery license. The company announced that "hydrocarbons were encountered."

The president of StatoilHydro Canada, Erik Abrahamsen seems delighted with the find, but cautions it could take two years to ascertain the Mizzen's true contents. "This is a big day for StatoilHydro," said Abrahamsen. "For us, it's a big step forward. We need to analyse the data and then in a year or two we might be in a position to go on with further appraisal drilling to find out more."

He also pointed out that deepwater pay dirt can take more than a decade to develop. "If the further appraisal drilling proves enough reserves to make this economically viable for development then you are looking at (at) least 10 years — maybe more, 15 years — before you can see any development and production from this possible field."

Other activity includes Petro-Canada using the Henry Goodrich to drill two development wells at Terra Nova and an exploration well on its Ballicaters (EL-1092) prospect in the Jeanne d'Arc basin. After that, it will return the rig to Husky, which may drill its Primrose (EL-1089) and Wild Rose (EL-1067) prospects in the Jeanne d'Arc basin. ●


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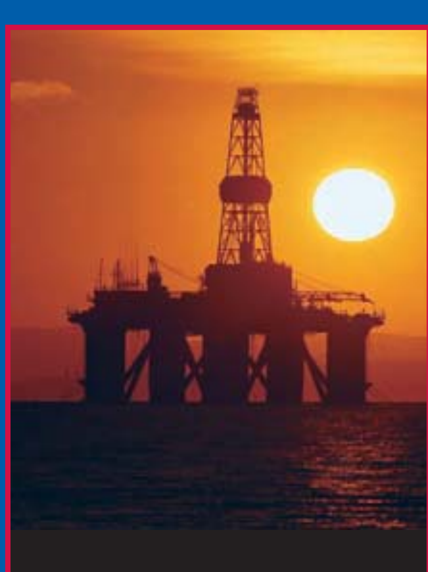
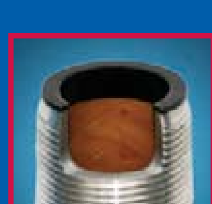




● GOVERNMENT

Stevens: State needs 'incentive climate'

Alaska must unite to tout its natural resource potential to world industry and Washington, ex-senator tells Alliance crowd

By WESLEY LOY
For Petroleum News

Citing the spirit and drive of statehood proponents 50 years ago, former U.S. Sen. Ted Stevens said Alaskans today must unite in a bipartisan effort to "encourage global industry to invest in our state."

It means moving beyond infighting over such issues as which route a natural gas pipeline should take and instead working to "create an incentive climate" of the sort that's yielding dream projects in other states and nations, Stevens said.

He made the remarks in an Oct. 1 speech at the annual meeting of the Alaska Support Industry Alliance.

TED STEVENS

It was the first major public address for Republican Stevens since he lost his bid for re-election last November, shortly after a Washington, D.C., jury convicted him of failing to disclose gifts on his Senate financial disclosure forms. A federal judge later set aside the conviction after the Justice Department acknowledged prosecutors withheld evidence that could have helped the defense.

Stevens, 85, never touched on the subject of his defeat or legal troubles during his 21-minute speech at the Sheraton hotel in downtown Anchorage.

The big crowd of drillers, truckers, suppliers, bankers and others who support Alaska's oil and gas industry greeted Stevens with a standing ovation.

His speech largely reflected his 40-year tenure in the Senate, where he championed resource development as Alaska's economic lifeblood and tilted with what he calls extreme environmentalists keen to block such activities as drilling in the Arctic National Wildlife Refuge.

Sounding nearly as intense as when he was a power player in Congress, Stevens noted Alaska's declining oil production and said residents face an imperative to "start something new" and halt the "constant delays" that threaten the state's future.

"You face challenges much more complex than the fight for statehood," he told his audience.

Internal struggles

Resource development, which helped make statehood possible, "has been in many ways stagnant now for almost a decade," Stevens said.

"We're now paying the price," he said, with Cook Inlet running short of natural gas to fuel the state's population centers and oil production from the inlet and the North Slope at less than half the 2 million barrels per day seen two decades ago.

"It's just a matter of time, without new discoveries, that decline threatens the continued operation of the trans-Alaska pipeline," Stevens said. "And our gas line … which should have started 10 years ago is stuck in the slow lane."

To some degree, Alaskans themselves are to blame, he said.

On the gas pipeline, "We've argued too much about the route and still not reached a consensus."

He continued: "Seeking increased income from declining production, inconsistent government policies and litigation, continue to hinder new industry including oil and gas and mining."

> *"You face challenges much more complex than the fight for statehood."*
> **—former U.S. Sen. Ted Stevens**

Further infighting could hurt the state in the long run, Stevens suggested.

"Much has been said about the need for Alaskans to get our fair share of oil and gas revenues. All of us agree with that. The question is, what's fair? And for whom? For those of us here now or for our grandchildren? Income from the oil and gas industry has provided state revenue, jobs, the Permanent Fund, lower personal taxes and the Permanent Fund dividend."

Creating an 'incentive climate'

Alaskans must come together in a bipartisan way to focus themselves, and the world, on the great development opportunities in the state, Stevens said.

"Many of the best projects in the world for energy development are right here," he said. "People are inclined to forget, two-thirds of the outer continental shelf is off our shores. Enormous oil and gas potential is there. There's vast potential in hydrates, and half of the coal in the United States is in our state. The Alaska gas pipeline, the National Petroleum Reserve, ANWR, and coal-to-gas or coal-to-liquid are tremendous opportunities for the future of this country.

"Those are our projects. Alaskans need to promote a new energy paradigm to create an incentive climate in this state for investment in our state and to renew a common effort to convince Americans of the national necessity for resource development here in Alaska."

Stevens mentioned some big projects elsewhere that he said are the result of industry incentives.

In South Dakota, a series of legislative initiatives this decade has prodded that state's oil and gas production to record highs and encouraged development of a coal-to-liquids plant, he said.

In Australia, Stevens said, government incentives to the oil and gas industry are helping bring about the giant Gorgon liquefied natural gas project, which will generate more than 6,000 jobs and $300 billion in LNG exports.

"Examples of new development that may compete with our projects are rampant. BP has its new discovery in the Gulf of Mexico, Brazil with enormous energy finds off the coast," Stevens said.

"We need new incentives now for industry to develop our resource potential," he said.

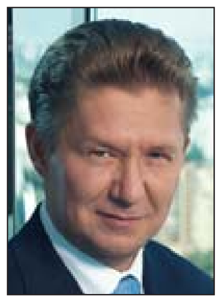
Singing Alaska's song

"There is a dire need for coordinated,

see STEVENS page 13

OUR ARCTIC NEIGHBORS

Gazprom commissions Yamal railroad bridge



Gazprom CEO Alexey Miller

Russia's state-owned energy giant Gazprom has commissioned a bridge over the Yuribey River floodplain on the Yamal Peninsula, part of the Obskaya-Bovanenkovo railroad, the company said in a release Sept. 24. The 2.5-mile-long bridge is the longest north of the Arctic Circle and should have an operating life of 100 years, according to Gazprom.

"The new railroad thoroughfare, designed to connect Yamal's (gas) fields with the transportation infrastructure of the northern Urals, will become a crucial component of the national strategic project to develop the Yamal Peninsula's fields," said Gazprom's CEO, Alexey Miller. "The year-round delivery of cargo, equipment and personnel to develop Yamal will enable us to rapidly form a new gas province on the peninsula of fundamental importance for the development of Russia's gas industry over the coming decades."

—SARAH HURST

Russian energy companies overloaded with work

Russia should establish a new state-owned company to develop offshore Arctic oil and gas resources because Gazprom and Rosneft are already committed to huge projects, a member of the Russian Academy of Sciences said at the RAO/CIS Offshore conference in St. Petersburg Sept. 18. Alexei Kontorovich won the Global Energy Prize 2009 from Russia's Global Energy Foundation for his research.

"Unquestionably Gazprom and Rosneft are very professional, experienced, leading companies," Kontorovich said. "But Gazprom has got huge obligations on long-term development at fields where production volume is decreasing; it needs to develop Yamal, the Shtokman gas condensate field and the resources of East Siberia. Each of these programs will require extremely large investments. Rosneft faces approximately the same situation, as it has received a number of highly promising fields in Eastern Siberia where a large volume of geological exploration is required. All these tasks cannot be postponed for long."

To develop Russia's offshore Arctic resources it will be necessary to drill more than 56 million feet of deep-hole wells in the most severe climatic conditions, Kontorovich added.

—SARAH HURST

Murmansk ready for action on Shtokman project

Russia's northwestern Murmansk Oblast is ready to become a base for development of the Shtokman gas field in the Barents Sea and is looking forward to working with its Norwegian partner in the Shtokman project, StatoilHydro, Grigory Stratiy, the head of the Murmanshelf Association of Oil and Gas Industry Suppliers, said at the RAO/CIS Offshore conference in St. Petersburg Sept. 18.

The Murmanshelf Association is a good example of international cooperation, established at the initiative of StatoilHydro in agreement with the government of Murmansk Oblast, Stratiy said.

"I like the way StatoilHydro engages local contractors for work," he added. "We have constructive dialogue with Shokman Development as well; the company has introduced into its regulatory documents a subclause stating that priority for participation in the project will be given to companies and suppliers registered within the territory of Murmansk Oblast.

"We know the capabilities of local industrial companies and can evaluate the contribution to be made by them into (the) preparatory phase of developing the Shtokman field. It makes me glad that Shtokman Development has already developed contractual strategy principals and conducts open policy-planning seminars with suppliers."

—SARAH HURST

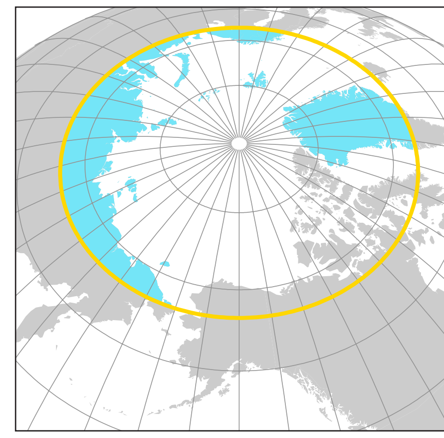
● OUR ARCTIC NEIGHBORS

Russia reopens for Arctic energy business

Government acknowledges need for international partners in remote regions but will maintain firm control of selection process

By SARAH HURST
For Petroleum News

Russia needs international expertise and technology to develop its vast Arctic oil and gas resources, and in return for that the country invites foreign companies to participate in projects, Prime Minister Vladimir Putin told Western energy bosses Sept. 24. The chief executives of ConocoPhillips, ExxonMobil, Shell and other majors received this welcome news from Putin at a televised meeting in Salekhard on the Yamal Peninsula.



The announcement marks a turnaround from Russia's previous policy of hindering foreign companies and awarding all large projects to state-owned Gazprom and Rosneft.

"I can assure you that you have not made this long trip to the end of the earth in vain," Putin said. "Many of you have been working with Russian companies in many parts of Russia successfully and for a long time. Many others are our marketing partners. Together we have done a lot, but there is still much more we can do."

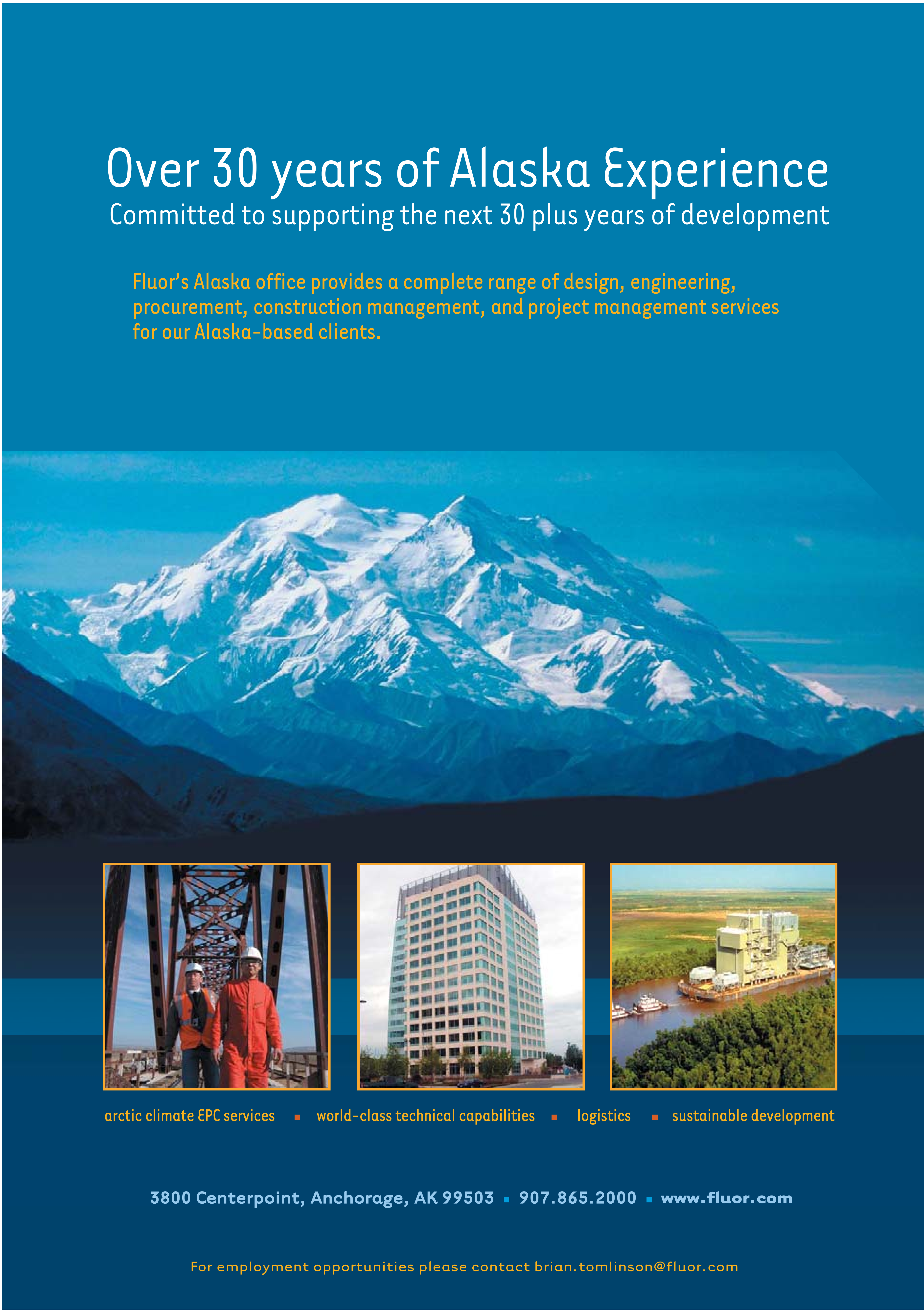
The Yamal-Nenets Autonomous Okrug accounts for about 90 percent of Russia's gas production, Putin told the executives. It has an estimated 4,414 trillion cubic feet of gas, according to the prime minister, compared with 106 trillion to 123 trillion cubic feet in the Shtokman deposit in the Barents Sea, which itself is considered huge.

"I would like to draw your attention to this figure, because it shows that Russia is certain to remain the absolute leader in gas production and sales for the next few decades," Putin said. "And, of course, we can resolve our domestic energy problems and honor all of our export commitments," he added.

"The fact that we have met here today, and that we invited you here, is evidence of our respect for the technology and production standards at your companies. It is also evidence of our respect for our joint achievements of the past few years," Putin said. "It is evidence of Russia's commitment to remaining an energy power with an open and liberal market economy. We invite our main partners to take part in joint projects. We hope to find solutions, even in the most challenging projects, which will be acceptable and interesting to us and to our partners."

Russia's deputy minister of natural resources and ecology, Sergei Donskoy, made a similar announcement Sept. 16 at the RAO/Offshore oil and gas conference in St. Petersburg. Noting that Russian law currently permits offshore exploration only by companies with at least 50 percent state ownership and at least five years' experience working on the Russian continental shelf, Donskoy said that only Gazprom and Rosneft meet those criteria.

"We are convinced that in order to work in the harsh conditions of the Arctic seas we must attract advanced technologies and significant financial resources, including from private Russian and foreign sources," Donskoy said. The way to do this is to create consortiums with state companies having a controlling interest but with private companies participating, he added. The government should play a key role in selecting consortium partners and in balancing the companies' commercial interests with Russia's strategic development and national security concerns, Donskoy continued. ●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LAND & LEASING

Renaissance transferring inlet leases

Renaissance Alaska LLC is in the process of transferring its onshore and offshore Cook Inlet basin leases to a new company, Stellar Oil & Gas LLC, owned by Renaissance executives Mark Landt, James Watt, Alan Huckabay and Vijay Bangia, Landt, Renaissance vice president for land and administration, told Petroleum News Oct. 6. The transfer of leases to the new company will enable the owners of that company to raise capital specifically for Cook Inlet exploration, as distinct from exploration in northern Alaska, he said.

During the summer Renaissance transferred its offshore Cook Inlet leases in the Northern Lights prospect to Escopeta Oil & Gas, as part of a deal that resulted in the formation of the Escopeta-owned Kitchen Lights unit.

"We are seeking new funding for our exploration activities in the Cook Inlet," Landt said.

In northern Alaska, Renaissance is hoping to develop the Umiat oil field on the eastern side of the National Petroleum Reserve-Alaska.

Northern Lights acreage transferred

During the summer Renaissance transferred its offshore Cook Inlet leases in the Northern Lights prospect to Escopeta Oil & Gas, as part of a deal that resulted in the formation of the Escopeta-owned Kitchen Lights unit. Northern Lights forms a down-dip extension of the undeveloped Sunfish oil discovery underneath the ConocoPhillips North Cook Inlet gas field. The Kitchen Lights unit encapsulates three distinct offshore oil and gas prospects: Northern Lights, Corsair and Kitchen.

The hope is that Escopeta will be able to attract the capital necessary to bring a jack-up rig to Cook Inlet, to drill in Kitchen Lights, Landt explained. Stellar Oil & Gas might then be able to use that same rig to drill in 10,008 acres of offshore leases that Renaissance retained after the conclusion of the Kitchen Lights deal. Those retained leases include prospects at Middle Ground Shoal and Northwest Cook Inlet, Landt said.

In addition to the offshore acreage, Renaissance is transferring 47,582 onshore acres covering the North Sterling and West Eagle prospects on the Kenai Peninsula to Stellar Oil & Gas.

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

—ALAN BAILEY

● F I N A N C E & E C O N O M Y

$70 WTI this winter, $75 by end of '10

Energy Information Administration expects energy prices to remain volatile, begins tracking futures prices with assessment of range

By KRISTEN NELSON

Petroleum News

West Texas Intermediate crude oil is expected to average about $70 a barrel this winter, the U.S. Department of Energy's Energy Information Administration said Oct. 6 in its short-term energy and winter fuels outlook.

EIA expects average WTI prices to rise to about $75 a barrel by December 2010 as U.S. and world economic conditions improve, based on an assumption of 1.8 percent growth in U.S. gross domestic production and a world oil-consumption-weighted GDP growth of 2.6 percent.

The agency has begun tracking futures prices "and the market's assessment of the range in which those futures might trade" and said its monthly outlook will report confidence levels around New York Mercantile Exchange crude oil and natural gas futures prices using a measure of risk derived from Nymex options markets known as "implied volatility."

EIA expects natural gas inventories to set a new record high at the end of the year's injection season, Oct. 31, reaching more than 3.8 trillion cubic feet; the Henry Hub annual average spot price is expected to increase from $3.85 per thousand cubic feet in 2009 to $5.02 in 2010.

Implied volatility

"Starting this month, EIA is including a quantitative measure of price uncertainty based on options market transactions in our monthly Short-Term Energy Outlook," EIA Administrator Richard Newell said in an Oct. 6 statement. "The new measure characterizes the degree of uncertainty in futures market prices, and provides perspective on the range of possible energy prices."

Nymex futures market participants were pricing WTI delivered to Cushing, Okla., in December at an average of $68 per barrel during the five days ending Oct. 1, EIA said. The 95 percent confidence level for those December futures contracts "ranges between $48 per barrel and $96 per barrel, a $48 per barrel difference," with about a 5 percent chance prices will fall outside of that 95 percent confidence interval.

In the same period, natural gas futures on Nymex were trading at $5.64 per million Btu for gas delivered to Henry Hub, La., during December. The 95 percent confidence interval around this price ranges between $3.70 and $8.60, a difference of $4.90 per million Btu.

Oil demands revised upward

EIA said sustained economic growth in China and signs of a turnaround in other Asian countries continue to fuel expectations of a world oil consumption recovery; the agency has revised its oil consumption expectations upward by 200,000 barrels per day for the remainder of 2009 and 2010.

But the WTI oil price expectation has not been revised because there are ample oil supplies on the market, with inventories high and Organization of the Petroleum Exporting Countries production expected to increase.

"EIA's current macroeconomic outlook assumes that the world economy begins to recover at the end of 2009, led by non-OECD Asia," the agency said.

U.S. natural gas consumption down

U.S. consumption of natural gas is projected to decline by 2 percent in 2009 and by 0.2 percent in 2010, as weak economic conditions continue to hamper the industrial sector, where natural gas consumption was down 12.4 percent through July compared to the same period in 2008.

"With lower consumption in the residential and commercial sectors as well, natural gas use in the electric power sector continues to serve as the only demand outlet for increased natural gas supplies," EIA said, with electric-power-sector natural gas consumption up by 0.4 percent in 2009 through July, compared to the same period last year, despite a 5.3 percent decline in total electricity generation.

EIA said it expects natural gas consumption growth in the commercial and industrial sectors in 2010 to be offset by a decline in the electric power sector, with fewer cooling degree-days expected next year, combining with higher natural gas prices and the startup of new coal-fired generating capacity expected to contribute

see EIA OUTLOOK page 19

● PIPELINES & DOWNSTREAM

House bill requires two tugs for tankers

Provision in Coast Guard bill would extend dual escorts even to ships with double hulls; similar legislation pending in Senate

By WESLEY LOY
For Petroleum News

Federal legislation authorizing Coast Guard appropriations for 2010 has a provision expanding the requirement for dual tug escorts of oil tankers traveling through Alaska's Prince William Sound.

The Coast Guard bill, H.R. 3619, would require that double-hulled tankers, and not just single-hulled ships as the law now specifies, be accompanied by at least two emergency towing vessels.

Supporters of the provision say it's important because nearly all the tankers carrying North Slope crude oil through the sound today are equipped with double hulls, a result of reforms Congress mandated after the wreck of the single-hulled tanker Exxon Valdez in 1989.

Oil industry watchdogs as well as Alaska's congressional delegation say they prefer that the oil industry continue with the dual tug escorts, even though the double-hulled tankers are thought to be less vulnerable to oil spills.

Two tugs "will allow for greater redundancy in a place where severe weather and human error can lead to disaster," said Alaska Republican Congressman Don Young, calling the Exxon Valdez oil spill "the worst tragedy" in state history.

The House Transportation and Infrastructure Committee passed out the Coast Guard bill on Sept. 24. Young has a seat on the committee.

The dual tug escort language is similar to that in a standalone piece of legislation Alaska's two senators, Republican Lisa Murkowski and Democrat Mark Begich, introduced on May 14.

That bill, S.1041, isn't expected to advance. Rather, the two senators are expected to try to insert the tug provision into other legislation, possibly the Senate's Coast Guard authorization bill.

Escorting each oil-laden tanker with two tugs is expensive, and industry watchdogs with the Prince William Sound Regional Citizens' Advisory Council have said they're worried oil companies might try to eliminate the expense now that the fleet has gone almost exclusively double-hulled.

But oil shippers have insisted they have no immediate plans to drop dual escorts.

The tanker fleet now numbers about 16 ships that regularly call on the oil terminal at Valdez. The bulk of them carry crude for BP, ConocoPhillips and ExxonMobil. ●

continued from page 9

STEVENS

planned action to assure that global enterprises recognize Alaska's resource potential," Stevens said. "This entails ensuring confidence in our state's willingness to maintain a favorable fiscal environment for industry while protecting the natural environment and lifestyle that we all enjoy.

"Nationally, a coordinated campaign is needed to convince Americans of the need to utilize our Alaska resources."

He noted the nearly $1 trillion economic stimulus package Congress approved for infrastructure and other projects, saying it represents a great opportunity for a unified Alaska.

"A bipartisan coalition is needed now to assure that the administration is aware of the opportunities here in Alaska, so we may leverage part of those resources to build our state's future. We succeeded as a bipartisan team throughout our history, and I think that approach is more critical today than ever before."

Stevens received another standing ovation at the end of this speech.

And, showing perhaps he has relaxed a bit from his Senate days, Stevens stood up later in the evening to sing a little of "King of the Road" as part of the Alliance's wacky amateur talent show. ●

EXPLORATION & PRODUCTION

Surmont expansion decision upcoming

According to the new CEO of Total E&P Canada, the decision to build the second phase of the Surmont oil sands project will be made at the end of 2009 or the beginning of 2010. Total is a 50 percent partner in the Alberta project that is operated by ConocoPhillips. Surmont production has been averaging about 18,000 barrels per day for more than a year and is designed to reach 110,000 bpd if the second phase of development is approved.

Jean-Michel Gires, who took the reins at Total in Canada in late August, told the Canadian Press, "We would expect that new phase to be sanctioned either by the end of this year or the beginning of next year." A steam-assisted gravity drainage operation, Surmont is southeast of Fort McMurray.

Assuming it receives regulatory approval, a decision on Total's Joslyn North mine, northwest of Fort McMurray, is not expected until oil prices improve.

"Currently, oil at about $60 to $70 U.S. per barrel we think is not enough to justify some of the significant projects we are contemplating, especially on the mining side," Gires said in a late September Reuters interview. "Eighty dollars to $85 a barrel would be ... the necessary price level we would need. But obviously we are contemplating these projects not only for the next year but for the very long term."

—PETROLEUM NEWS

SAFETY & ENVIRONMENT

DOI sends polar bear rule to White House

The U.S. Department of the Interior has sent its proposed rule for the protection of polar bear habitat to the White House Office of Management and Budget, Greenwire has reported, according to a New York Times article published Oct. 6.

With the polar bear now listed as threatened under the Endangered Species Act, the U.S. Fish and Wildlife Service, an agency within Interior, must determine the critical habitat for the bears and specify how that habitat will be protected.

But there is considerable interest in how that critical habitat and its protections might be specified — the polar bear is a marine mammal that spends much of its time on the Arctic sea ice. Interior recognizes that the retreat of the sea ice as a result of global warming constitutes the main threat to the future of the bears, given their dependence on the ice in hunting for the seals that form their main diet.

Given the difficulty of using the ESA to regulate climate change and the greenhouse gases thought to be the main culprit in global warming, Interior under the Bush administration attempted to decouple the ESA from the climate change issue — under a special ESA rule for the polar bear listing, a rule upheld by the Obama administration, carbon dioxide emissions outside the polar bear's territorial range cannot be considered as a "take" of the bears.

—ALAN BAILEY

ASSOCIATIONS

IAEE to hear mechanics of cap and trade

The functional mechanics of how Congress' proposed "cap and trade" climate change legislation would work will be presented by Patrick Lavin, attorney for the Alaska region of the National Wildlife Federation, at the Anchorage Chapter of the International Association of Energy Economics, on Oct 14 at noon at the BP Energy Center.

Admission is free for members. There is a suggested donation of $5 for non-members.

Contact Roger Marks at 250-1197 or rogmarks@gmail.com for information.

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ENSTAR

on the agency's regulations.

The state said that is essentially what Enstar is doing by including $5.7 million in gas costs in its current gas cost adjustment and charging 2009-10 customers for gas consumed as much as five years ago.

"Such operation of the GCA mechanism is neither contemplated nor permitted under the current regulations," the state said.

ConocoPhillips

Von Hutchins, in pre-filed testimony for ConocoPhillips Alaska, said the purpose of his testimony was to ensure that the factual record in the case, as it relates to ConocoPhillips, is correct, and that RCA "does not inadvertently characterize the facts in a way that jeopardizes" ConocoPhillips' claims against Enstar in separate litigation.

After Enstar discovered its error, the Department of Defense demanded $1,903,971.19 from ConocoPhillips for overcharges for gas supplied to the department from Oct. 1, 2002, to Sept. 30, 2004.

This is in addition to the $5.7 million for overpayment of gas contracted through other producers.

Hutchins, director of gas supply and marketing for ConocoPhillips' Cook Inlet gas assets, said that since Enstar caused the error, ConocoPhillips has demanded reimbursement of the $1.9 million from Enstar, but Enstar has refused to reimburse ConocoPhillips.

He said Enstar does not deny that there was an error, but maintains that its tariff provides that it is only required to "adjust for billing errors up to 36 months from the date of any invoice," and these invoices are older than 36 months.

Hutchins said this was not a billing error: "The bills themselves were accurate because the amounts billed correctly calculated the product of volumes consumed multiplied by a rate," and thus ConocoPhillips "could not have known of the error because the bills, on their face, were mathematically correct."

Enstar's error, he said, "was in its internal recording of the amount of gas consumed."

Error predated Conoco contract

That error began before ConocoPhillips began supplying gas to the Department of Defense, so "the error was already embedded in the baseline meter readings by the time CPAI started to provide gas" to the department in 2002, Hutchins said.

ConocoPhillips contracted with Defense to provide the natural gas and then separately contracted with Enstar to provide transportation and Hutchins said the transportation contract required Enstar to maintain and operate measuring facilities and to test the accuracy of measuring equipment monthly.

He said the meter in question was one of eight separately itemized in the November 2002 bill to the Department of Defense and deliveries of gas at that time "overwhelmingly were directed to the power plant that was still in use."

Of volumes in November 2002 — had Defense been billed correctly — the total would have been 160,478 thousand cubic feet or mcf; of that total, 76 mcf or 0.05 percent was for the meter with the error, had that volume been shown correctly.

He said the ten-fold error from the one meter, meter 118, was such a small percentage of the total, 0.4 percent, as to be "a nearly imperceptible … blip on the total bill for the example month highlighted."

The bills were too high when ConocoPhillips began supplying gas, he said, "and there was no sharp ten-fold increase in the bills" after the company took over that reflected Enstar's error.

Aurora wants gas

Scott Pfoff, president of Aurora Power Resources, said in filings with RCA that Aurora has sued Enstar in Superior Court over more than 800,000 mcf of Aurora's gas which Enstar received as a result of incorrect billings from the laundry meter.

He said that in compliance with its agreements with Enstar and with Enstar's tariff, Aurora has requested the return of the oversupplied gas and a credit for transportation charges for the oversupplied volumes.

"Enstar ignored Aurora Power's request for over six months and thereafter denied Aurora's requests," he said.

The gas transportation agreement governing Enstar's transportation of gas specifies filing of actions in Superior Court, Pfoff said.

Pfoff said Enstar's response to the filing was to move for dismissal of Aurora's complaint or for transfer of the litigation to RCA for a determination of the issues. While the Superior Court refused to dismiss the complaint, it did grant the jurisdictional motion in part, "effectively transferring the matter to the RCA for its review and comment."

Pfoff said the problem with the Enstar meter occurred before Aurora began its gas supply contract with the Department of Defense, so Aurora did not have a frame of reference to compare usage before the meter change with usage after, and it "had no reason to question, or to be alarmed by the volumes of gas that Enstar reported as being delivered to the (Department of Defense) laundry meter."

Resolution, Pfoff said, lies in return by Enstar of the oversupplied gas. He characterized this as a measurement error and said there have been numerous such errors over the years "similar to this one, albeit not as large." In those cases Enstar has credited or debited the invoice to Aurora Power for the transportation billing portion of the error and debited or credited the gas imbalance account. ●

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HYDRATES

Gas hydrate (or more correctly "methane hydrate") consists of a white crystal-like substance that concentrates natural gas by trapping methane molecules inside a lattice of water molecules (methane is the primary component of natural gas). The hydrates remain stable within a certain range of temperature and pressure, but when decomposed yield about 164 times their volume in methane.

On the Web

See previous Petroleum News coverage:

"Field test of CO2-CH4 exchange planned," in Oct. 4, 2009, issue at www.petroleumnews.com/pnads/315842975.shtml

"One step at a time for gas hydrates," in Jan. 18, 2009, issue at www.petroleumnews.com/pnads/672064283.shtml

"ANS hydrate test results promising," in Nov. 11, 2007, issue at www.petroleumnews.com/pnads/16906500.shtml

Huge volumes

The huge volumes of methane locked up in gas hydrate deposits straddling the base of the permafrost under the North Slope could become a major source of natural gas for export through a future North Slope gas line if, that is, researchers can solve the puzzle of how to produce gas from the hydrates in a sustainable and economically viable manner. The central North Slope is one of the world's most favorable sites for possible gas hydrate production, because the hydrates are on land close to an existing oil and gas infrastructure.

In 2007 BP drilled the Mount Elbert gas hydrate stratigraphic test well from an ice pad in the Milne Point unit, a drilling venture that formed part of the same project that is now evaluating production test sites.

The Mount Elbert well enabled the recovery of gas hydrate samples and some limited testing of the production characteristics of the hydrates found around the well bore. And results from Mount Elbert, and from another well, the Mallik gas hydrate test well in northern Canada, have convinced the U.S. Geological Survey to classify some gas hydrate deposits as "technically recoverable," with the most likely production mechanism being depressurization of free gas associated with the hydrates — depressurization through a production well would cause some hydrate to decompose, thus releasing more free gas.

Sustained production?

But the path toward moving some of the known gas hydrate deposits into an "economically recoverable" status requires, among other things, a demonstration that effective gas production from the hydrates can be sustained over long periods of time. Hence the need for a production test of the type that the North Slope team is planning: The brief insights into production that were gained at Mount Elbert and Mallik may or may not presage successful long-term, viable production possibilities.

"A reservoir's initial production response often provides limited insight into actual deliverability due to transient effects that are very difficult to understand," Collett and Boswell said. "Because the time required for the production response to stabilize may take many months or more, a key criterion for gas hydrate production testing is the availability of a site that allows continuous access over a sufficient duration to provide meaningful data on reservoir performance. This could mean only a month or so if the test produces large and stable volumes quickly; it could mean several years if all the planned contingencies for supplemental testing need to be invoked."

And the need for long-term access to the test site will require the use of an existing gravel well pad, rather than a temporary ice pad of the type used at Mount Elbert, they said.

Unfortunately, the need for a long-term well pad precludes the possibility of using the Mount Elbert surface well site for a production test, thus requiring the use of "a high-angle to horizontal well path that would cross at least one major fault" to access the Mount Elbert gas hydrate deposits from an existing gravel pad, Collett and Boswell said. And although Mount Elbert offers the advantage of a proven and tested gas hydrate deposit, the complexities of the required drilling, completion and logging operations would significantly raise the risk, and presumably the cost, of the project.

Low temperatures

The Milne Point gas hydrate reservoirs themselves also suffer from a significant disadvantage: Reservoir modeling indicates that the relatively low temperatures of between 2 degrees and 3 degrees Celsius in the reservoirs would likely delay initial production of gas after a well has been drilled, while also slowing subsequent production. Temperatures just a few degrees higher would eliminate the production delay and substantially increase production rates, the modeling shows.

These various issues at Milne Point are pointing the researchers toward the use of the Prudhoe Bay L pad, where hydrate-bearing reservoir sands close to the well pad are similar to the Milne Point reservoirs and about 3 C warmer. Another possible Prudhoe Bay location, at the old Kuparuk State 3-1-11 well, does not have an operational gravel pad and would require a significant investment in infrastructures upgrades, Collett and Boswell said.

Other sites considered consist of a couple of locations on the eastern margin of the Kuparuk River unit, and a location to the east of Prudhoe Bay L pad. The Kuparuk locations appear to suffer from reservoir temperature issues similar to Milne Point, while presenting a higher level of geologic risk. The location to the east of L pad presents the major advantage of reservoir temperatures around 12 C, but suffers from a lack of nearby surface facilities, as well as lacking nearby well penetrations to confirm reservoir continuity. ●

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MAC LINE

the Joint Review Panel report, expected in December 2009," NEB said in a press release.

The Joint Review Panel is examining the potential environmental, socioeconomic and cultural effects of the 720-mile pipeline project, whereas NEB is looking at all other issues, including engineering, safety and economic matters.

As part of its mandate, NEB has to "consider the Joint Review Panel's recommendation and its proposed remedial measures," NEB said.

Remedial measures could be incorporated as conditions into any approvals NEB grants the Mackenzie Gas Project.

In an Oct. 7 statement to the Calgary Herald, Pius Rolheiser, spokesman for Imperial Oil, the lead partner in the gas project, said: "It's encouraging to see some confirmation of some critical points in the regulatory process," noting that if NEB approves the gas line project, the partners will have to evaluate the decision and any conditions imposed before deciding whether to proceed with the pipeline and related facilities.

"The Mackenzie Gas Project is one of the largest infrastructure projects to ever be proposed in this country," said NEB Panel Chair Ken Vollman. "It has been a long road to get to this point and we are very pleased to be approaching the final stages of our journey."

Once final arguments are concluded NEB will make its decision and prepare a document called a "Reasons for Decision," that will essentially announce its decision regarding the gas line application, and provide the reasoning behind its decision.

The partners in the Mackenzie Gas Project are Imperial Oil Resources Ventures, the Aboriginal Pipeline Group, Imperial Oil Resources, ConocoPhillips (North), Shell Canada and ExxonMobil Canada Properties.

—PETROLEUM NEWS

Oil Patch Bits

NAC awards William Dix Fowler Memorial scholarship

Northern Air Cargo said Oct. 1 that Clyde Hoffman, a junior at the Atheneum School of Anchorage, was the recipient of the second annual William Dix Fowler Memorial scholarship.

The scholarship consists of annual awards of $1,000 each to worthy recipients, chosen by the school. Hoffman, this year's recipient, was chosen for his leadership and dedication to learning. "I've met Clyde, and I don't think they could have made a better choice for this award. We are grateful to be able to do something like this in Bill's name," said Margot Wiegele, NAC's director of marketing and communications. Fowler was the president of Northern Air Cargo from 2001 until March of 2008, and was also actively involved in supporting the Atheneum School.

STB completes final FEIS for the Alaska Railroad

The Alaska Railroad said Sept. 25 that the Federal Surface Transportation Board has completed the Final Environmental Impact Statement for the Alaska Railroad Corp. application to construct and operate a rail line between North Pole and Delta Junction. Known as the Northern Rail Extension, the project would offer safe freight and passenger rail service to communities southeast of North Pole; support agriculture, mining and petrochemical industries; and provide year-round reliable access to military training areas. The FEIS includes a recommended route and mitigation measures to offset impacts from construction. The STB's Record of Decision is expected by the end of October. For more information visit www.akrr.com.

Tom Crowley receives prestigious NTA award

TOM CROWLEY JR.

Crowley Maritime Corp. said Sept. 30 that Tom Crowley Jr., the corporation's chairman, president and CEO, was presented with the prestigious National Transportation Award from the National Defense Transportation Association, at the group's annual logistics forum and exposition in Nashville, Tenn.

"Our relationship with the Department of Defense is as diverse as Crowley and the different services we provide," said Crowley, who said he was pleased to accept the award on behalf of the 4,300 Crowley employees around the world providing services to the DOD and government.

Jacksonville-based Crowley Holdings Inc., a holding company of the 117-year-old Crowley Maritime Corp., is a privately held family and employee-owned company that provides diversified transportation and logistics services in domestic and international markets. For more information visit www.crowey.com.

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.

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

SAFETY & ENVIRONMENT

EPA moves to regulate smokestack gases

Industrial plants emitting at least 25,000 tons would have to use best available technology with new builds, significant changes

By DINA CAPPIELLO
The Associated Press

The Environmental Protection Agency took steps Sept. 30 to control the emissions blamed for global warming from power plants, factories and refineries for the first time.

The EPA proposal would require polluters to reduce six greenhouse gases by installing the best available technology and improving energy efficiency whenever a facility is significantly changed or built. The rule applies to any industrial plant that emits at least 25,000 tons of greenhouse gases a year.

These large sources are responsible for 70 percent of the greenhouse gas emissions — mainly carbon dioxide from burning fossil fuels — that are released in the U.S., the EPA said.

"By using the power and authority of the Clean Air Act, we can begin reducing emissions from the nation's largest greenhouse gas emitting facilities without placing an undue burden on the businesses that make up the vast majority of our economy," EPA Administrator Lisa Jackson said. "We know the corner coffee shop is no place to look for meaningful carbon reductions."

Earlier this year, the Obama administration announced that it would start developing the first-ever greenhouse gas emissions standards for cars and trucks. Those regulations, which would take effect in 2010, compel the EPA to control greenhouse gases from large smokestacks as well, the agency said.

Industry questions argument

Industry groups immediately questioned the agency's argument. They charged that the EPA was skirting the law, since the Clean Air Act typically covers any facility releasing more than 250 tons a year of a recognized pollutant. That threshold would require more facilities to fall under the new regulations.

"This proposal incorrectly assumes that one industry's greenhouse gas emissions are worse than another's," said Charles T. Drevna, president of the National Petrochemical and Refiners Association.

Jeff Holmstead, a former top EPA air pollution official who is now a lobbyist for

These large sources are responsible for 70 percent of the greenhouse gas emissions — mainly carbon dioxide from burning fossil fuels — that are released in the U.S., the EPA said.

the energy industry, said the agency was trying to "fit a square peg into a round hole."

"Normally, it takes an act of Congress to change the words of a statute enacted by Congress, and many of us are very curious to see EPA's legal justification for today's proposal," Holmstead said.

Jackson, speaking at a news conference at a climate change summit being hosted by California Gov. Arnold Schwarzenegger, said the rule was legally defensible.

"The EPA would not propose a rule that we didn't believe ... made good legal sense," she said.

Congress considering legislation

The EPA's announcement came hours after Senate Democrats unveiled legislation that would set limits on the amount of greenhouse gases from large industrial sources. The Senate bill, unlike the House-passed version, preserves the EPA's authority to regulate under the Clean Air Act.

Environmentalists said Sept. 30 the two efforts go hand-in-hand.

"You can't have one without the other if we're going to be successful in moving America to clean energy," said Emily Figdor, director of the global warming program at Environment America, an advocacy group.

The move will likely increase pressure on Congress to pass a bill to avoid less-flexible, and what Republicans said would be more costly, regulations. Supporters of the legislation have already used pending EPA rules as leverage to get Congress to act.

Senate Republicans have already attempted to block the EPA from issuing regulations to buy more time for Congress to work on a bill. At least one Republican leader, Sen. James Inhofe of Oklahoma, said Sept. 30 that Congress would try to stop the EPA again. ●

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MERGERS

credit certificates based on its past qualifying exploratory expenditures in the state.

This company merges with or sells out to either another independent explorer already working in the state, or a new independent explorer that's just arriving.

Either way, generally, the certificates belonging to the company that goes away as a result of a merger or sale are still good, the advisory bulletin says.

The bulletin notes the opinion does not apply to the transfer or reassignment of tax credit certificates as part of a bankruptcy proceeding.

Sixth advisory so far

The state Tax Division has done half a dozen such advisory bulletins since the office gained authority to do them under Alaska's Clear and Equitable Share, the oil production tax reform the Legislature passed in late 2007.

"We created this authority for ourselves in ACES," said Marcia Davis, the state's deputy revenue commissioner.

It was needed because industry would often ask whether the state could advise on how a given activity, situation or deal would be treated for tax purposes, Davis said. State officials wanted the capacity to offer such guidance, she said, much like the IRS does.

State officials are happy to address questions not just from oil companies, but from nontraditional players, Davis said.

"It doesn't have to be a taxpayer. It could be someone from outside the state contemplating doing business in Alaska," she said.

Prior advisory bulletins addressed such questions as whether oil recovered from North Slope waste streams would be subject to the state's oil and gas production tax (it wouldn't, tax officials advised); whether a geophysical company is considered an "explorer" eligible for tax credits when it undertakes seismic work on spec (it is); and whether natural gas used in a manufacturing process such as making fertilizer is considered an in-state use of gas eligible for a production tax break (yes and no).

All six advisory bulletins are available at www.tax.state.ak.us/programs/whatsnew.aspx.

Credit cashouts mount

In July, the Department of Revenue announced the state had paid $193 million in cash over the preceding fiscal year to oil and gas explorers in exchange for tax credits they had accrued for making investments in the state. The money went to 15 explorers not yet producing any oil or gas in Alaska, the department said.

So far this fiscal year, which began July 1, "we have processed and approved the cash purchase of $72,566,816 in tax credits," Davis told Petroleum News in an Oct. 7 e-mail.

The credits are essentially advance rebates on future taxes that companies will owe once they begin production. Companies present proof of their spending to the state to build tax credits and swap them for cash.

State officials recognize that a big challenge for oil and gas explorers is the huge expense they must risk upfront before they ever produce the first barrel, state Revenue Commissioner Pat Galvin told Petroleum News in July. By allowing them to cash in tax credits with the state, the belief is it helps encourage exploration and investment. ●

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CROSSROADS

issues at one point on the grid inevitably impact power generation elsewhere on the grid.

So, how did the Railbelt reach the current situation and what's to be done about it?

Modern era

The modern era of energy supplies in Southcentral Alaska dates back to the 1960s and 1970s, the heyday of oil exploration in and around Cook Inlet, following the discovery of oil at Swanson River on the Kenai Peninsula but predating the rush for the Cook Inlet exit door following the discovery of the giant Prudhoe Bay oil field on the North Slope.

Cook Inlet oil exploration resulted in the successful development of several oil fields, but it also resulted in the discovery of large amounts of natural gas and the development of some large gas fields. A gas industry was established, consisting primarily of new LNG and fertilizer plants at Nikiski on the Kenai Peninsula, to use the excess gas that had been discovered.

The excess and, therefore, cheap gas also found a ready side market with local electricity and gas utilities, thus establishing natural gas as the primary means of heating Southcentral homes and business, and as the primary fuel for generating electricity.

But the Southcentral gas industry has transitioned through a classic oil and gas production profile, with production rapidly peaking and then going into a long, slow decline. With the decline in gas production, the Nikiski fertilizer plant shut its doors in 2007. And although, at about the time that fertilizer production stopped, ConocoPhillips and Marathon, the owners of the LNG plant, successfully applied for an extension of the LNG export license through to 2011, the owners are now monitoring the availability of gas for the plant before deciding on whether to apply for a further license extension.

Utility gas supplies have severely tightened, with Enstar Natural Gas Co., the main Southcentral gas utility, projecting a shortfall in supplies around 2014 or 2015.

Deliverability

However, the immediate issue relating to utility gas supplies is achieving sufficient deliverability — the ability to flow enough gas from the gas fields — to meet peak demand during the coldest periods of the winter. In the severe cold of January 2009 the utility gas system came close to its deliverability limits, so that with gas deliverability having declined further since then, a gas deliverability shortfall looms if there is a severe cold snap in the winter of 2009-10.

Part of the deliverability problem is the lack of sufficient gas storage to save excess summer gas for use during the winter, despite the fact that Marathon and Chevron have established three storage facilities in depleted underground reservoirs. But, unfortunately, new storage facilities take years rather than months to develop, and are expensive.

Enstar is working with Houston-based ANR Pipeline Co. to fast track the development of a new storage facility, to plug what Enstar sees as an otherwise inevitable deliverability gap in 2011. Aurora Gas also wants to develop a gas storage facility at its Nicolai Creek gas field. And part of the looming deliverability problem for 2011 is the possible closure of the LNG plant — the plant currently provides an invaluable service by diverting gas supplies otherwise intended for LNG production, to meet utility gas deliverability shortfalls.

Unfortunately, given the amount of capital tied up in the existing natural gas infrastructure, any large-scale transition from gas to electricity as a prime means of space heating in buildings would be extremely expensive and take several years to accomplish. Apart from the necessity of building new power generation, transmission and distribution capacity, Southcentral residents would need to replace gas-fired boilers and other equipment in homes and businesses.

More to find

But there undoubtedly is more gas to find in the Cook Inlet basin.

The problem is that, despite a U.S. Department of Energy statistical analysis of existing gas fields that suggested the existence of 10 trillion to 14 trillion cubic feet of undiscovered gas in the basin, no one knows how much undiscovered gas is truly there. And the Cook Inlet region is a difficult and expensive place to explore in, given the combination of remote terrain, little support infrastructure, harsh winter climate, challenging geology and an undersized support industry.

Apart from a small handful of large offshore structures that require ultra-expensive drilling from a jack-up rig, the main structures in the basin have already been drilled — much new exploration needs to focus on smaller, subtle gas prospects.

The lack of a spot market for the sale of gas has also proved problematic for new entrants to the Cook Inlet gas business — utility gas supplies tend to be tied up in medium- or long-term contracts.

On the other hand, with quite a low density of oil and gas wells, the Cook Inlet basin remains relatively underexplored. And Cook Inlet newcomer Armstrong Oil and Gas has expressed confidence in the Cook Inlet as an exploration region, having signed a gas supply contract with Enstar for gas from the North Fork field in the southern Kenai Peninsula.

Exploration uptick

In fact, the early 2000s saw an uptick in Cook Inlet gas exploration drilling, presumably as a consequence of upward signals in Cook Inlet gas prices as the gas supply situation tightened. And established gas producers in the basin have done some exploration and development drilling in recent years, apparently to assure their abilities to meet their contracted gas supply obligations.

But much more new drilling is needed to make any progress in turning back the tide of declining gas supplies. Meantime, in what one Regulatory Commission of Alaska commissioner has characterized as the "Cook Inlet gas war," RCA, the gas producers, the utilities and the State of Alaska have wrangled over establishing appropriate price levels for Cook Inlet utility gas. Gas producers need incentives to find and produce new gas, while gas consumers want to minimize their gas costs.

As an alternative to Cook Inlet gas supplies, there are proposals to bring North Slope gas to Cook Inlet, either through a direct "bullet line," or through a spur line from a main North Slope gas export line. But the economics of bringing North Slope gas to Southcentral would require industrial gas demand, perhaps from an LNG or petrochemical plant located in Southcentral.

And, at current trends of Cook Inlet gas decline, North Slope-sourced gas would be unlikely to become available in Southcentral before Cook Inlet gas supplies fall short of demand. That raises the specter of possibly having to import foreign LNG through the Nikiski LNG plant, to boost utility gas supplies. The import of LNG, although straightforward to arrange, would require Alaskans to swallow copious quantities of their pride in a state that boasts major oil and gas resources.

Alternative sources

But what about alternative sources of energy?

The obvious alternative to natural gas is coal, a fuel that exists in great abundance in several regions of Alaska, including on the western side of Cook Inlet and at Healy on the north side of the Alaska Range, where it is currently mined. Fairbanks-based Golden Valley Electric Association operates a coal-fired power station at Healy and is planning to bring a mothballed clean coal plant online at Healy as well.

But coal has suffered from a tarnished environmental image in recent years and tends to be particularly intensive in its production of carbon dioxide, the gas that has become the bête noire of the global warming debate. Clean coal power plants, especially those involving the sequestration of carbon dioxide, are expensive to construct and may be expensive to operate. And the future economics of any fossil fuel, including natural gas, is uncertain because of the possibility of future cap and trade regulation of carbon dioxide emissions.

Hydropower is another possibility. The modest-sized hydroelectric system at Bradley Lake on the Kenai Peninsula, for example, has proved very successful in

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CROSSROADS

providing power for the Railbelt grid. And two potential larger hydropower systems are under consideration: a 300-megawatt system at Lake Chakachamna, 80 miles northwest of Anchorage, and the 1,200-megawatt Susitna project, involving the damming of the Susitna River at a couple of locations south of the Alaska Range. The Susitna system could approximately meet the current power load for the whole of the Railbelt but would require major upgrades to the electrical intertie between Fairbanks and Anchorage.

Wind power looks to be coming into fruition with the likely construction of a wind farm on Fire Island, in Cook Inlet offshore Anchorage. This project should make a modest but valuable contribution to Railbelt electricity supplies. Other wind farm sites appear to be possibilities.

A proposed tidal power system, using the huge tidal range of Cook Inlet and located in Knik Arm adjacent to Anchorage, could also make a modest but valuable contribution to power supplies and is undergoing environmental analysis, with a possible prototype turbine installation in the offing. A much larger tidal power system has been proposed for Turnagain Arm on the west side of Anchorage. Any tidal system would need to accommodate environmental concerns, especially concerns about the movement of fish and the possible impact on the Endangered-Species-Act-listed Cook Inlet beluga whale.

There's also a company investigating the possibility of farming geothermal energy from the flanks of Mount Spurr, the closest active volcano to Anchorage.

Commercial issues

But any major power generation project, such as a Susitna Dam or a large coal-fired plant, will run into commercial issues relating to the size of the Alaska Railbelt power market and the fact that the Railbelt grid, a small power grid in comparison with those of more typical North American populations centers, is operated by no less than six independent power utilities. And, while the implementation of a major new power plant by one utility would likely impact the economics of power generation by the other utilities, it's also unlikely that any one utility has the financial wherewithal to build the type of massive plant that would achieve the economies of scale necessary for least-cost power generation.

And the implementation of a power generation facility feeding electricity to more than one of the major electrical demand centers of the Kenai Peninsula; Anchorage and the Matanuska-Susitna Valley; and Fairbanks would require major and expensive upgrades to the power transmission interties between these centers, interties which currently have fairly limited transmission capacity and represent single points of failure for gridwide power transmission.

And then there's the knotty question of whether a new major power plant should use natural gas, coal or some form of renewable energy source, a question that might require some form of state policy intervention for its answer. Part of the problem here is that a new major coal-fired plant, for example, might seriously undermine the economics of a new hydroelectric plant, and would also impact the economics of bringing North Slope gas into Southcentral Alaska.

AEA report

A study commissioned by the Alaska Energy Authority and published in 2008 recommended the implementation of a regional power generation and transmission entity that would take over from the existing utilities the development, management and operation of all power generation and transmission in the Railbelt, to achieve economies of scale and a coordinated approach to generation and transmission across the region. The existing utilities would retain management of local power distribution.

In March 2009 then Gov. Sarah Palin introduced a bill in the state Legislature to form a corporation along the lines of the AEA recommendations. But it did not prove possible to adequately deal with the legislation within the remainder of the legislative session, and consideration of the bill was deferred into 2010.

So, it remains to be seen how the various pieces of the Railbelt energy jigsaw puzzle can be assembled, hopefully before the lights go out as power stations run short of fuel. ●

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WANTED

Foreland gas field on the west side of Cook Inlet, but Division of Oil and Gas official Alan Dennis, who is in charge of Pacific Energy's former assets for the state, said the division released an RFP on Oct. 1, looking for a contractor to "basically finish the work we've started to winterize the assets and look after (all the assets that were operated by Pacific Energy) for a longer term."

According to the state's Request for Proposals, an emergency procurement, "the properties to be maintained and operated under this contract include the West McArthur River oil facility, West Foreland gas facility, Kustatan processing facility, Osprey oil platform, Mosquito Station and associated wells, roads and pipelines."

The RFP, the purpose and title of which is "Preserve Abandoned Cook Inlet Facilities," offers bidders three proposals, any combination of which would be considered, Dennis told Petroleum News. The RFP specifies that responses "must demonstrate the ability to perform all three scenarios" as well as having the ability to implement changes at the direction of the state project manager.

The scenarios are as follows: A. ice-cold shutdown; B. warm shutdown; C. "operating the oil field at West McArthur, as well as operating the gas field at West Foreland," said Dennis. In all scenarios described in the RFP Redoubt and Kustatan would be in cold shutdown.

All of the oil wells at West McArthur are currently shut-in, that process completed by early September, Dennis said.

"One gas well is operational at West Foreland, to run a turbine at West McArthur River. We need the electricity it generates to do the freeze completion work," he said.

Some, or parts, of the properties in the RFP are not on state land.

"No one else was going to do anything, so we stepped in to preserve the assets until an ultimate outcome is determined for them. While the owners decide what will happen, we're making sure nothing is spilled on the ground," Dennis said.

The RFP was sent to the following: Bill Penrose at Fairweather; Randy Frazier at FEPSI, or Fairweather E&P Services Inc.; Mark Nelson and John Lewis at ASRC Energy Services; Ben Cleveland at Peak; Cook Inlet Energy; Mark Landt at Renaissance; Ed Kerr and Ed Teng at Armstrong; Milton Allen at Udelhoven; Jordan "Digger" Smith with Ramshorn (partner in Brooks Range Petroleum); Paul Smith with Nabors; and Gary Carlson. No company name was listed for Carlson in the email that transmitted the RFP.

—KAY CASHMAN

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EIA OUTLOOK

to a reduction in natural-gas-fired electric generation next year.

U.S. gas production up

U.S. marketed natural gas production is expected to increase by 1.5 percent this year and decline by 3.8 percent next year, EIA said. Production was up 2.9 percent through July compared to the same period last year, despite a decline in the working rig count of more than 40 percent since January.

The agency expects that, while production has remained stronger than expected this year, the pullback in natural gas drilling will lead to a 3.6 percent reduction in Lower 48 production from the first half to the second half of the year.

U.S. liquefied natural gas imports are expected to increase to about 471 billion cubic feet in 2009, from 352 bcf last year, and rise to some 660 bcf next year.

The projected working gas inventory Oct. 31, the end of the injection season, is some 285 bcf above the previous record of 3.565 tcf reported for the end of October 2007. ●