Petroleum news

Vol. 18, No. 2 • www.PetroleumNews.com A weekly oil & gas newspaper based in Anchorage, Alaska Week of January 13, 2013 • $2

page 8 Oil taxes top Chenault's list, along with spending, in-state gas

'Cold' author takes on firey topic

LISANNE AERTS

Bill Streever, author of "Heat: Adventures in the World's Fiery Places," examines flowing lava on a volcano in Hawaii Volcanoes National Park. See page 20.

Southcentral utilities leaning toward the use of diesel fuel

BREAKING NEWS

The Southcentral Alaska utilities are considering the use of diesel fuel for some power generation, in the event of a predicted utility natural gas supply shortage around 2014-15, Robert Gibb, associate director of Navigant Consulting, told the Mayor's Energy Task Force in Anchorage on Jan. 9. Gibb is helping the utilities and the planned Donlin Creek gold mine evaluate the options for dealing with the pending Southcentral gas supply crisis.

The utilities have been investigating the potential import of liquefied natural gas or compressed natural gas into Southcentral to cover the gas shortfall. But with some significant uncertainties associated with these options, the utilities now tend to favor the diesel fuel option as a safe means of dealing with the problem in the short term, despite the fuel's high cost. The utilities will also seek a cost-effective long-term solution, Gibb said.

Short- and long-term

"What we've done on this project very recently is we've

see DIESEL POWER page 30

Salazar says Interior to assess Shell's 2012 operations in Arctic

Interior Secretary Ken Salazar has announced that the Department of the Interior is going to conduct an expedited, high-level assessment of Shell's operations in the Arctic in 2012. The review, which should be completed within 60 days, will focus on the challenges that Shell encountered with its containment barge, the Arctic Challenger; the deployment of the company's new containment dome; and operational issues with the two drilling rigs, the Noble Discoverer and the Kulluk, Interior said in a Jan. 8 press release accompanying Salazar's announcement. The review will examine Shell's safety management systems, the company's oversight of its contracted services and the company's ability to meet the strict standards in place for Arctic development, Interior said.

ALAN BAILEY

KEN SALAZAR

Tommy Beaudreau, the director of the Bureau of Ocean Energy Management, will lead the review, with U.S. Coast Guard providing technical assistance.

"Developing America's domestic energy sources is essen-

see INTERIOR ASSESSMENT page 30

EXPLORATION & PRODUCTION

Change of plans

'Sour gas' forces ExxonMobil to modify well array in Point Thomson field

By WESLEY LOY

For Petroleum News

ExxonMobil is making a significant change to its planned Point Thomson project due to an unexpected "sour gas" problem involving the two wells already drilled at the remote Alaska North Slope field.

In 2010, the company finished drilling two wells on Point Thomson's central pad, the PTU-15 and the PTU-16. One well was to be a producer and the other an injector for the natural gas condensate project.

But during well testing, ExxonMobil encoun-

see POINT THOMSON page 26

Walker's Point Thomson challenge tossed

A judge has thrown out Bill Walker's challenge to the state's Point Thomson settlement with ExxonMobil and other oil companies.

Walker is an Anchorage attorney and a former candidate for governor.

He filed an administrative appeal in state Superior Court following the March 29, 2012, resolution of the dispute surrounding the Point Thomson field on the eastern North

see SETTLEMENT CHALLENGE page 27

EXPLORATION & PRODUCTION

Checking it out

ROVs inspect Kulluk hull in Kiliuda Bay after successful refloat and tow

By ALAN BAILEY

Petroleum News

There were cheers off the shore of Sitkalidak Island, on the southeast side of Kodiak Island, at around 10:10 p.m. on Jan. 6 as members of the Kulluk tow incident response team watched the anchor handling vessel, the Aiviq, successfully pull the Kulluk, Shell's floating drilling platform, off the shallow cobble terrace where the vessel had remained stuck since going aground on Dec. 31.

Multiple overflights of the grounded drilling rig and a series of on-site inspections by a team of salvers over a period of several days had preceded the decision to try to pull the Kulluk from the shore. The teams had determined that, although some seawater had leaked into the vessel through unsecured hatches, the vessel's hull and fuel tanks were intact, and that the vessel would be stable

COURTESY SHELL

The anchor handling vessel Aiviq tows the Kulluk to a safe anchorage in Kiliuda Bay, on the coast of Kodiak Island.

see KULLUK REFLOAT page 31

PIPELINES & DOWNSTREAM

Decision time for rails

Alaska-Alberta proposal ready to launch feasibility study, needs C$40M backing

By GARY PARK

For Petroleum News

Two ventures aiming to break the logjam facing Western Canadian producers seeking new markets for their crude oil face crucial tests in January.

Vancouver-based Generating for Seven Generations, or G7G, is expecting to know whether it will get C$40 million in financing to study the feasibility of its plan to build a rail line from Alberta to Alaska to connect with the Valdez Marine Terminal, while a coalition of railroads and producers is scheduled to decide whether it will conduct an experimental shipment of 2 million barrels of crude this summer through the Hudson Bay port at Churchill, Manitoba, to either the North American Atlantic Seaboard or Europe.

The bid for the G7G rail link is a revival of a century-old dream and studies commissioned in 2005 and 2007 by the Alaska and Yukon governments to build a resource-based line tying Alaska with Canada and the Lower 48 to import and export a variety of goods.

G7G Director Matt Vickers said his company's plan involves a 1,600-mile rail line from the Alberta oil sands to Delta Junction, Alaska, where

see DECISION TIME page 29

contents

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● FINANCE & ECONOMY

Legislature heads back to oil tax fray

Alaska House, Senate leadership put production in top three issues for session; governor expected to offer new bill in January

By KRISTEN NELSON
Petroleum News

Returning Alaska House Speaker Mike Chenault, R-Nikiski, and in-coming Senate President Charlie Huggins, R-Mat-Su, told the Resource Development Council Jan. 3 that budgets, the oil tax and an in-state gas pipeline would be the top three issues when the Legislature gavels in Jan. 15.

The last Legislature struggled in both its 2011 and 2012 sessions with the oil production tax and with revisions to the state's in-state gas pipeline statute, failing in the end to agree on changes to either.

The House passed a version of the oil tax bill introduced by Gov. Sean Parnell in 2011, but it failed to gain any traction in the Senate, which studied the issue and developed its own bills in the 2012 session, the first of which failed to reach the floor of the Senate and the second of which passed the Senate at the very end of the session, but was not considered by the House.

The 2010 federal census and redistricting produced a different Legislature in the 2012 elections.

This year the Senate majority is dominated by Republicans, 13 of the 20 members with two Democrats caucusing with the Republicans, whereas in the last Legislature the 16-member Senate Bipartisan Working Group consisted of 10 Democrats and six Republicans, with four senators in the Republican minority. Three of the previous Legislature's minority Republicans are now in leadership positions in the Senate: Huggins as president, John Coghill as majority leader and Cathy Giessel as the Resources Committee chair.

The House, as in the previous Legislature, has a Republican majority, with rural Democrats caucusing with the Republicans.

Revenue Commissioner Bryan Butcher said in early December when the department rolled out its fall forecast that the department was working with the Department of Law on what would go into a tax change proposal.

This time around, he said, the department has had the time and the consultants to dig through the tax issues "and really try to come up with as well-rounded an approach as we possibly can."

Butcher said the administration plans to submit a tax bill to the Legislature in January.

2011-12

In the 2011-12 sessions the House passed both an oil tax bill and an in-state gas bill, but the Senate didn't move the in-state gas bill and the Senate majority was only able to agree in the last days of the 2012 session on a partial oil tax change, for new oil only, a proposal the House didn't consider.

The governor called the Legislature into special session immediately after it adjourned to consider oil taxes and the in-state gas line; the in-state gas line again stalled in the Senate.

The governor introduced a special session oil tax bill April 18, the first day of the session, and withdrew it April 25, citing lack of support in the Senate.

Parnell called the position of some in the Senate "hard-line," and said "the Senate appears incapable of passing comprehensive oil tax reform."

The governor's special session bill combined the new-field tax allowance proposal the Senate developed at the end of the regular session (a 30 percent 10-year allowance on both the base tax and progressivity) with a similar approach for existing fields, a 40 percent deduction on progressivity only.

House Bill 110, passed by the House in 2011 and never taken up in the Senate, provided across the board tax reductions for all North Slope oil production. Senators said in 2011 that they needed more information before considering changes in the state's oil production taxes, changed in 2006 with the Petroleum Profits Tax and again in 2007 with ACES, Alaska's Clear and Equitable Share. The progressivity rates in ACES at current oil prices have been cited by industry as a disincentive to investment in the state, because the state takes progressively more in taxes as oil prices rise. Crude oil prices have risen above what was projected when ACES was passed.

Additional oil

While HB 110 would have cut production taxes across the board, providing incentives just for new oil was the only agreement the Senate majority was able to reach in the regular session which ended in mid-April.

Some members of the Senate Bipartisan Working Group said they believed ACES was working just fine.

Others in the majority, including Senate Finance co-Chair Bert Stedman, R-Sitka, said progressivity at high oil prices was a concern, noting that when work was done on ACES in 2007 the focus was on oil prices in a much lower range than they were in 2011-12.

As for what should be changed, legislators were told by consultant Pedro van Meurs in tax discussions prior to the 2012 session that total government take (state and federal taxes) for existing fields was within the world-wide norm at 70 to 75 percent.

North Slope production is on the decline and Parnell set a goal to increase throughput on the trans-Alaska oil pipeline to 1

see **OIL TAX FRAY** *page 4*

Proposed versus passed

In late March 2012 Senate Finance was working on revisions to ACES, Alaska's Clear and Equitable Share, the production tax enacted in 2007.

Bert Stedman, R-Sitka, co-chair of Senate Finance, said the committee would zero in on the progressivity aspect of ACES.

What follows is a reprint of a portion of an article from the April 1, 2012, issue of Petroleum News.

Then and now

Legislators have questioned why ACES isn't incentivizing new investment, based on analyses run of the proposed bill in 2007 which indicated the bill would not make the investment climate worse.

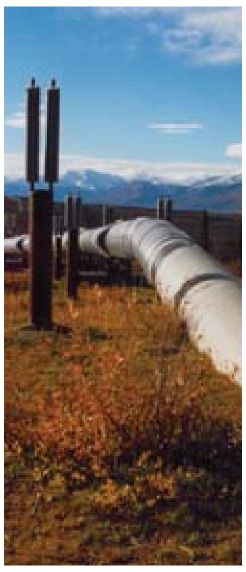
An October 2007 presentation to legislators by consulting firm EconOne included a slide entitled: "ACES Preserves Investment Climate."

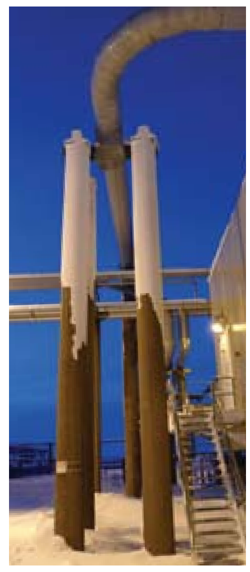
Stedman said March 22 that he asked PFC Energy, which is currently consulting for the Legislature on oil tax issues, to take a look at some of the old analysis and do comparative updates. He said the cost structure and the price range are different today than they were a few years ago, and wanted the committee to be able to see the differences.

Janak Mayer, manager in the upstream and gas practice of PFC Energy and project manager for the firm's work with the Alaska Legislature, said a lot of the analysis done during ACES came to the conclusion that ACES preserved the investment climate.

But Mayer said there are a lot of voices today saying "ACES has not preserved the

see **THEN AND NOW** *page 4*





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continued from page 3

OIL TAX FRAY

million barrels per day (from less than 600,000 bpd).

More oil moving through the line would require an increase in investment and in the 2012 regular session senators focused on finding a way to incentivize additional oil production without reducing taxes on existing production.

After weeks of work, first in Senate Resources and then in Senate Finance, senators produced a comprehensive oil tax bill, Senate Bill 192, but that bill wasn't able to garner enough support in the Senate Bipartisan Working Group to reach the Senate floor for a vote.

Following that, Senate Finance proposed a change only to taxes on oil from new fields, attaching that to a House bill providing credits and production tax breaks for unexplored or underexplored basins close to communities in need of more reasonably priced energy supplies.

The House Rules Committee moved the so-called "middle earth" provisions for unexplored basins to another bill, and the Senate's new oil tax reduction was never considered in the House.

Poorly received in Senate

The new tax bill the governor introduced in the special session was very poorly received in Senate Resources, where the governor's team — Revenue Commissioner Butcher and Deputy Commissioner Bruce Tangeman — were barely allowed to present the bill and even the Legislature's consultants, PFC Energy, came under fire.

Senate Resources members objected to the fact that the new bill, Senate Bill 3001, had about the same overall tax reduction as the governor's original 2011 proposal, HB 110.

Butcher said that the level of cut in oil taxes was close to that in HB 110, and said that was the level of tax cut the administration believed necessary to make a tax change "meaningful" enough to attract the new investment needed to increase production.

The House Resources and House Energy committees considered the bill and heard what the Senate had heard in the regular session from PFC Energy's Janak Mayer, that while cutting taxes across the board is the simplest way to incentivize investment, that method moves a lot of cash across the table unnecessarily, because a lot of the work the companies do in legacy fields is economic.

New field development is particularly challenged under the ACES tax regime, Mayer said, but incentivizing specific new oil developments, while putting money where it will do the most good in inducing more production, is more challenging than across-the-board cuts, both administratively and for industry.

The House committees had gotten to the point of taking testimony from industry April 25 and were preparing to hear public testimony April 26 when the governor pulled the bill.

Industry representatives, who had not yet testified in the Senate, told the House committees that House Bill 3001, the governor's special session tax proposal, made significant enough changes in the tax rate that it would result in more investment. ●

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OWNER: Petroleum Newspapers of Alaska LLC (PNA)
Petroleum News (ISSN 1544-3612) • Vol. 18, No. 2 • Week of January 13, 2013
Published weekly. Address: 5441 Old Seward, #3, Anchorage, AK 99518
(Please mail ALL correspondence to:
P.O. Box 231647 Anchorage, AK 99523-1647)
Subscription prices in U.S. — $98.00 1 year, $176.00 2 years, $249.00 3 years
Canada — $185.95 1 year, $334.95 2 years, $473.95 3 years
Overseas (sent air mail) — $220.00 1 year, $396.00 2 years, $561.00 3 years
"Periodicals postage paid at Anchorage, AK 99502-9986."
POSTMASTER: Send address changes to Petroleum News, P.O. Box 231647 Anchorage, AK 99523-1647.

continued from page 3

THEN AND NOW

investment climate or at least has not, in the current day, enabled an investment climate as significant as might be ideal."

He said that to understand those differences it was important to look at the analysis that was performed during the ACES debate, to look at what has changed since then, "and why therefore might we draw some different conclusions looking at this data pool today as opposed to the ones that were drawn back in 2007."

The 2007 analysis looked at seven hypothetical field developments with "a stylized production profile and particular capital and operating costs," Mayer said. The basic differences between 2007 and 2012 hold true across all the examples, he said, noting the sample field he selected from the 2007 analysis was "not dissimilar in its characteristics to the sort of hypothetical new development" that PFC Energy has used in some of its analysis.

ACES as proposed

The first thing to note, Mayer said, is that the October 2007 analysis was done on the ACES tax bill as proposed by the Palin administration, not on ACES as enacted by the Legislature. The administration proposed a 0.2 percent progressivity rate; the Legislature passed a 0.4 percent progressivity rate. The administration proposed capping the production tax rate at 50 percent; the Legislature capped it at 75 percent.

Mayer said the second thing "is that cost assumptions are much lower than any recent experience would suggest" in the 2007 analysis, which was based on $10 a barrel capital expenditures and $9 a barrel operating expenditures for a hypothetical new development, while the analysis PFC Energy presented for a similar development was based on $17 a barrel for both capex and opex.

Then there is the price of oil.

Analysis in 2007 was done on a minimum of $20 a barrel and a maximum of $100 a barrel "with a focus in particular on what the economics looked like at a $40 stress-test price and a $60 base case price for crude oil," he said.

The production profile for the hypothetical new development in the 2007 analysis was one that would maximize returns for the producer, with "quite a high peak production rate and a relatively high decline

see **THEN AND NOW** *page 5*

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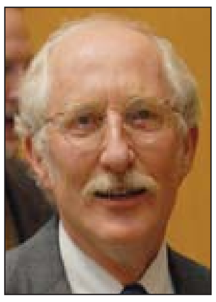
● FINANCE & ECONOMY

Economist to state: cut spending, save

Goldsmith projects that future oil and gas revenue can't sustain Alaska's current spending rate, inviting 'severe fiscal crunch'

By WESLEY LOY
For Petroleum News

Save more, spend less. That's long been economist Scott Goldsmith's advice for Alaska's oil-dependent state government, and he's offering it again in advance of the upcoming legislative session.



SCOTT GOLDSMITH

Whether to reduce oil taxes to spur industry investment is expected to be a big issue for lawmakers.

But that debate is not Goldsmith's focus. Rather, he warns the state is spending too much, and future oil and gas production can't sustain it.

"Reasonable assumptions about potential new revenue sources suggest we do not have enough cash in reserves to avoid a severe fiscal crunch soon after 2023, and with that fiscal crisis will come an economic crash," Goldsmith writes in a new analysis. "The answer is to save more and restrict the rate of spending growth."

The analysis was posted Jan. 3 on the website of the University of Alaska Anchorage Institute of Social and Economic Research. Goldsmith is a professor emeritus with ISER.

Find the analysis at http://bit.ly/110xbp2.

The 'fiscal gap'

For decades, Goldsmith has talked of the "fiscal gap," the different between revenue and spending.

For now, and for several years out, the state has ample money thanks to high oil prices and massive savings accounts including the Constitutional Budget Reserve, the Statutory Budget Reserve and the Alaska Permanent Fund. The current value of these financial assets is currently around $60 billion.

Longer term, Alaska faces trouble, says Goldsmith.

"If Alaska had $117 billion in cash reserves and the Permanent Fund by 2023, the state would be on the path to sustainable spending far into the future," he writes. "But ... that's twice what the state has in financial assets today. So the state needs to sharply step up its savings rate, starting now."

The state can still expect a very lucrative stream of oil and gas revenue. But it won't be adequate to sustain the state's current spending habit, Goldsmith says.

Oil and gas projections

Goldsmith's 14-page analysis includes concise projections of oil and gas production expected in Alaska over the coming 50 years.

The "net present value" of state petroleum revenues over that time horizon is $88.7 billion, Goldsmith projects.

"We determine this value by estimating future taxes and royalties for 50 years, assuming the current fiscal structure and energy prices as well as reasonable estimates of economically recoverable reserves, both known and unknown," the analysis says.

Most of the value, $67.1 billion, will come from 3.5 billion barrels of oil produced from known fields, the analysis says.

Another $9.9 billion is projected to come from "unconventional and new oil." This breaks down as follows: $4.8 billion in conventional oil from new fields on

see GOLDSMITH ANALYSIS page 32

continued from page 4

THEN AND NOW

rate, meaning that most production value occurs in the first 10 years," Mayer said, estimating that for a 60 million barrel field the peak would probably be 20,000 barrels per day with a rapid decline. He said a peak at some 11,000 or 12,000 bpd and a slower decline "is at least a little more consistent with some of what we've actually seen in terms of historical production data from North Slope developments" and particularly from new fields in that size range — Oooguruk and Nikaitchuq.

Benchmarking data

Both analyses benchmarked the government take in Alaska against other oil producing regimes. The 2007 analysis used a $60 a barrel reference case; PFC Energy has used $100 a barrel and $140 a barrel.

Where the 2007 benchmarking put Alaska under ACES as proposed at the high end of the median, the PFC Energy benchmarking at $100 a barrel put Alaska just under Norway, which has the highest government take of any developed country, and above Norway at the $140 a barrel level, Mayer said.

Looking at the hypothetical new development which was attractive under the 2007 assumptions, Mayer said that as the 2007 assumptions are changed to reflect 2012 prices and costs, with ACES as enacted rather than as proposed, "this goes from being an attractive field development under the previous cost assumptions to being suddenly one that really is very marginal."

The flatter production curve (lower peak production, longer field life), gives the project "strongly negative value to a company" at the $40 to $60 a barrel range, with a breakeven point probably in the $80 to $90 a barrel range and one which only starts to have any positive economic value at $100 a barrel.

Stedman summed up the presentation by noting that by the time this proposed new development is taken "from the proposed ACES to the enacted ACES and then adjust it for cost and price, we have a substantial different outcome" than that in the 2007 analysis.

—KRISTEN NELSON

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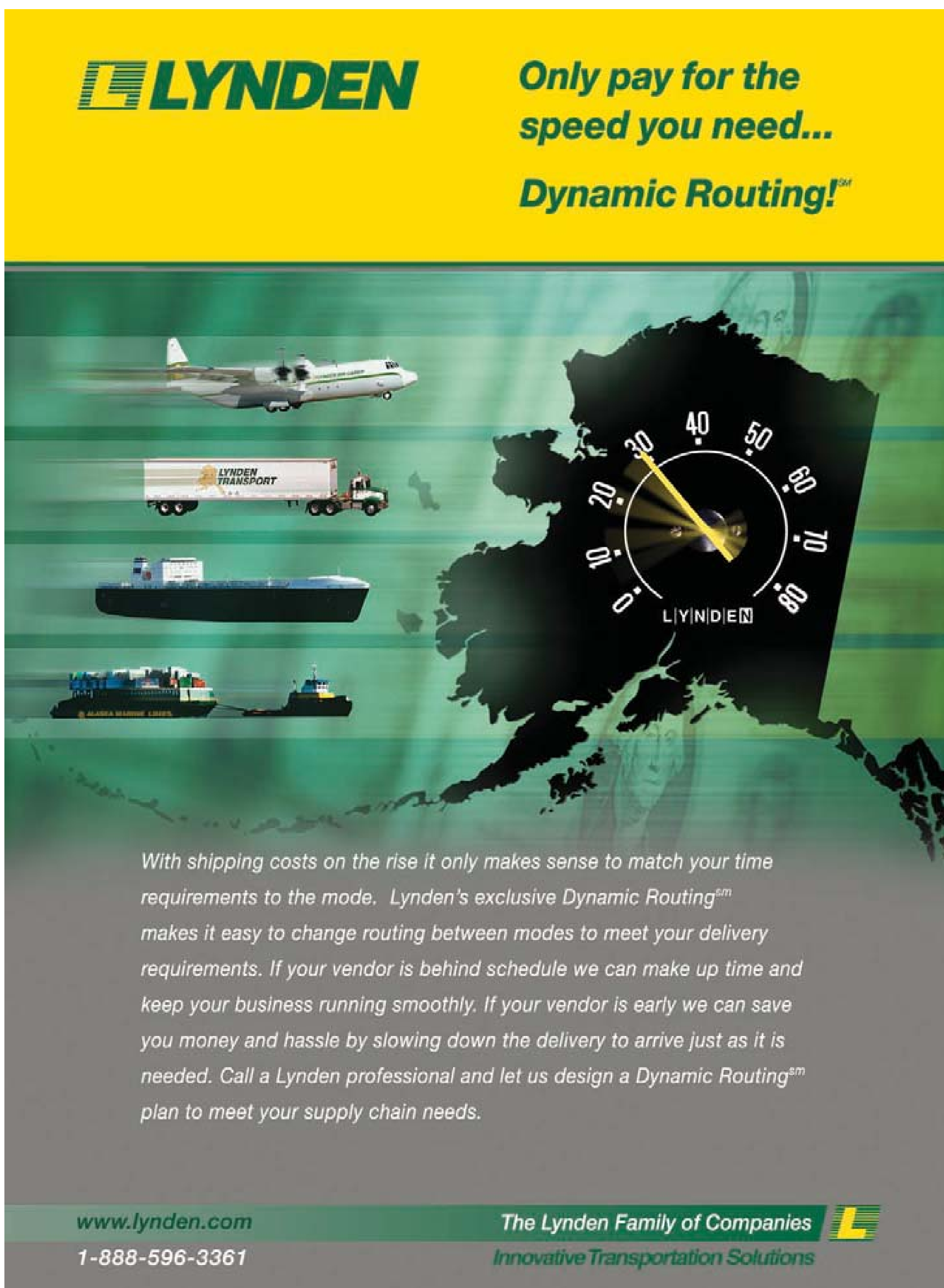

● PIPELINES & DOWNSTREAM

Pipeline squeeze chokes economy

Agencies, banks fuel estimates more than C$1 trillion of economic benefits at stake; industry losing at least C$50 million a day

By GARY PARK
For Petroleum News

Canada's Natural Resources Minister Joe Oliver is clinging firm to his conviction that Enbridge's Northern Gateway pipeline will proceed amid a raging controversy over proposed transportation projects.

And he has a huge cheering section, with the Canadian Energy Research Institute, the International Energy Agency and two Canadian banks joining the chorus recently of those who argue that the economic health of Canada's E&P industry hangs in the balance.


SHANE LASLEY
JOE OLIVER

The Canadian Energy Research Institute, CIRI, said in a new report that unless three major pipeline expansions go ahead C$1.3 trillion of gross domestic product and C$276 billion in taxes will be sacrificed over the next two decades.

Oliver described that outlook as a "serious issue" with no short-term solution.

"If we do not take heed of warnings and diversify our markets for energy by building infrastructure like pipelines, then our resources will be stranded and we will lose jobs and businesses in Canada," he told the Saint John Board of Trade in New Brunswick.

"We're losing C$50 million every single day — C$18 billion to C$19 billion every year — because our resources are landlocked."

He said that all of the latest reports repeat what his government has been saying "for a long time ... that the U.S. is going to be self-sufficient within the next 20 years and, at a minimum, we aren't going to be able to rely on them for growth."

"There is inadequate capacity in existing pipelines and it's getting pretty stark. None of this is news to us, but it is external confirmation of what we knew and it may even be coming a little faster," Oliver said.

He said the projections of lost revenues are likely even higher as the differential has increased, prompting CERI to project that the daily shortfall could be closer to C$75 million.

Oliver said the plight facing producers is "screaming out for us to diversify and we need pipelines to do that," noting that the Canadian government alone has been forced to stall by two years its plans for eliminating the budget deficit because of a C$6 billion revenue shortfall.

Price gap big issue

Alberta Finance Minister Doug Horner said the price gap between West Texas Intermediate crude and Western Canada Select (a blend of conventional heavy crudes and oil sands bitumen) is worse than he had originally believed when Alberta released its second-quarter fiscal update in November.

"I am very, very concerned about where those numbers are headed," he said.

CERI senior research director Dinara Millington said the price gap means Alberta is collecting lower royalties, while the federal and provincial governments have seen their corporate tax revenues decline.

Analysts doubt that even if pipeline expansions add 1 million barrels per day of new capacity that would wipe out the differential.

Horner said that pending the construction of new pipelines, Alberta producers could move their production by rail.

"We need to take a very serious look at every opportunity we have to expand our market access, because it is a critical component for a landlocked province," he said.

The commodity price spread, which is costing Alberta C$8.5 million a day in royalties or C$3 billion a year, is a "real ... growing concern," Oliver said.

Hope for Keystone XL

He expressed optimism that the Obama administration will soon approve the rerouted Keystone XL pipeline, connecting Alberta with the U.S. Midwest and Gulf Coast.

He also emphasized the importance of an expanded west-to-east pipeline system in Canada, as proposed by Enbridge and TransCanada, and the need for pipelines to the British Columbia coast to open routes to Asia.

Oliver said 2012 was the year that Canada "realized that diversification is utterly critical. We absolutely must be able to transport the resources to tidewater and to do that we need the infrastructure."

Despite the ongoing opposition to Enbridge's planned Northern Gateway and TransCanada's expansion of its Trans Mountain system, Oliver said he is "still of the belief that we can get Northern Gateway done, on the assumption that it passes regulatory muster."

He said that if the National Energy Board concludes the pipeline can be safely constructed that should "go a long way in respect at least to people who are open-minded to the facts."

Oliver said that even if British Columbia elects a New Democratic Party government this May, he suggested that administration should not be opposed to Northern Gateway if the current environmental review can allay concerns.

He said the Canadian government will continue its efforts to consult with aboriginal groups and ensure pipeline and tanker safety is the best it can possibly be, but added "We have a big job to do."

British Columbia Environment Minister Terry Lake said that far more than a favorable environmental review is needed to sway his government.

"We need to have our share of the benefits commensurate with the amount of risk," adding that if the risks can't be minimized "then it doesn't really matter what the benefits are."

However, he said that if Enbridge and the Canadian government can satisfy British Columbians they can meet the province's environmental, safety and economic conditions, the pipeline "certainly can be a possibility." ●

Contact Gary Park through publisher@petroleumnews.com

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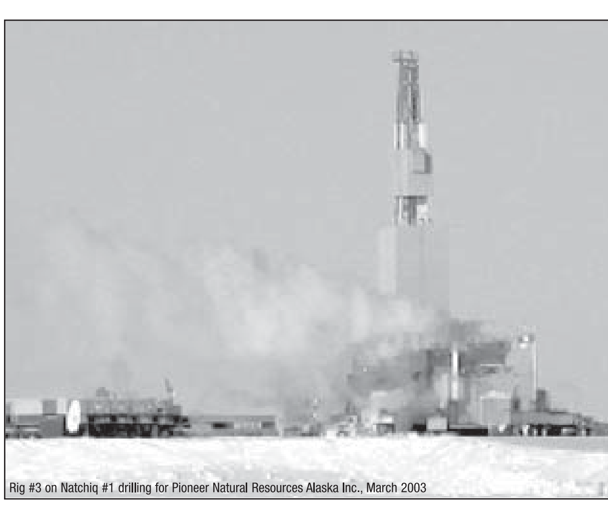
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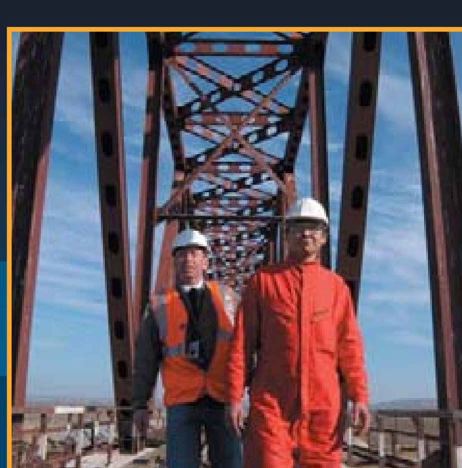

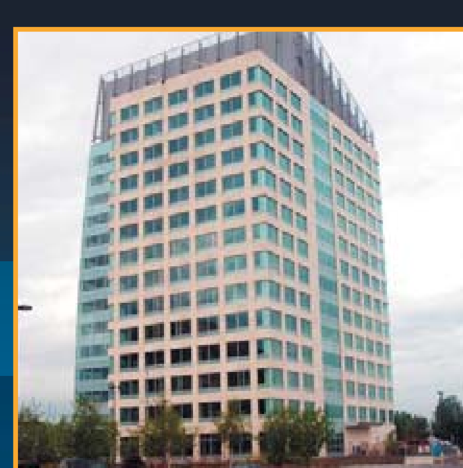

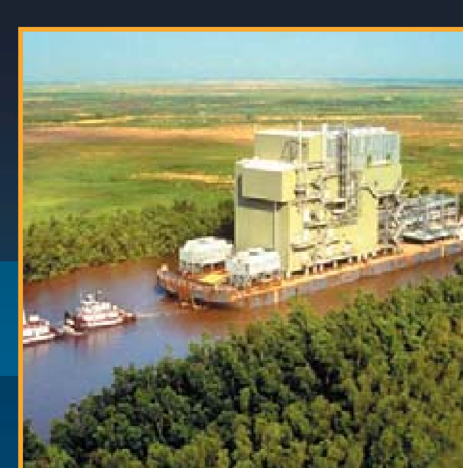

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● GOVERNMENT

Oil taxes top Speaker Chenault's list

Nikiski Republican returns for third consecutive term as House leader; targets tax issue, controlling spending, in-state gas pipeline

By STEVE QUINN
For Petroleum News

House Speaker Mike Chenault has been on the front lines of heavy-hitting resource development issues since he began serving in the Alaska Legislature 12 years ago.

Chenault began his legislative tenure in 2001 by immersing himself into the requisite resource committees (Natural Gas Pipelines; Oil & Gas; Resources Committee; Special Committee on Oil and Gas).

This month, Chenault, a Nikiski Republican, begins his third term as House Speaker, following back-to-back terms as Finance Committee co-chairman. He is the first Alaskan to enter a third consecutive term as House Speaker.

Now entering his seventh session in office, Chenault sat down with Petroleum News to discuss legislative priorities and other energy issues.

Q AND A

Petroleum News: What would you say are the legislative priorities in the coming year or two years?

Chenault: I think it comes as no surprise that one of the main issues that we've got to deal with will be oil taxes and how it plays into the big picture of moving Alaska forward and putting more oil into the (Trans Alaska) pipeline. It is Alaska's lifeblood. We need to control spending, not only the operating budget, but the capital budget as well.

Petroleum News: When you speak of oil taxes, do you or your caucus have a plan to put forward?

Chenault: We don't have a plan per se. There are a number of (lawmakers) out there who have different aspects they want to look at. Whether you talk to Rep. (Eric) Feige or Rep. (Mike) Hawker, just about everyone out there has their ideas of what they would like to see. I think what you'll see is in the first few weeks of the session there will be a number of legislators promoting different fixes. You'll see those go through the (committee) process and some combination of those will come out as a deal the Legislature can vote on.

Petroleum News: What do you think kept something from getting done during last two-year session? Was it an inability to agree on what would put more oil in the pipeline?

Chenault: The House passed House Bill 110 and the Senate didn't agree with that. I was told by the Senate "we spent a couple of years on researching how oil taxes ought to be put together and we'll send you a bill." The House never got a bill. What we got was a try at a long-term fix that didn't address any of our short-term needs. I can't specifically say they didn't attempt to address the issue, but from what it looked like to me, there was a lot of procrastinating on one side. They didn't really want to tackle the issue and come forward with a solution. They liked the amount we are taxing now. They didn't particularly care about the workers in the state of Alaska.


MIKE CHENAULT

Petroleum News: What do you think can be done next year, five years or 10 years out? Is it as simple as a tax rate reduction?

Chenault: On one hand we do need to look at long-term and new exploration and new fields. But we all know it's seven to 10 years before a new field will come online, so what if anything can we do to increase oil production in our existing fields. That's the $100,000 question.

What can we do to draw more oil out of the existing fields today? If you look at the bill that the Senate tried to give us in the last couple of days last year, what it looked like to us it was basically 10 years with no tax. Depending on the price of a barrel of oil, and the cap ex costs, you could have had a field come online and not pay a dime of tax for the first 10 years.

To me that was not the right answer, either. I think we should incentivize new exploration, and go out and look at new fields, but there are aspects of infield drilling that need a look. We know Prudhoe and Kuparuk are big fields, so how do we get new oil out of those?

Petroleum News: What are the chances of the Legislature addressing gas tax terms?

Chenault: At some point and time, the gas tax would have to be visited and a gas tax determined. When we will do that, I don't know. I wish we had done that four or five years ago before we did oil taxes, personally. I think we would be further ahead as far as getting a pipeline project. Could gas taxes be done? Sure. Would gas taxes have to be done before you get a final approval on a project? Yeah. Because not only the buyers but the sellers are going to want to know what their taxes are and what their costs are for that commodity. Until you determine the gas rates, that's a lot on your plate.

Petroleum News: With that in mind, the next priority seems to be advancing an in-state gas line project. You and Rep. Hawker have introduced House Bill 4. You fell short with a similar bill last year. What are the stumbling blocks to moving a project forward?

Chenault: Some of the biggest hurdles are regulatory issues and how do you get a project to an open season that allows buyers and sellers to put together a project that makes economic sense and one that they can move forward on. HB4, what it's intended to do is give AGDC the tools they need to get to that open season.

Petroleum News: One of the criticisms that seemed to prevail is that the bill offered too much power for AGDC (the Alaska Gasline Development Corp.) What are your thoughts on that?

Chenault: I don't think it gives them too much power. Naysayers say we don't have people who are smart enough. We don't have people like the oil companies do. They have the top guns. If we want to be effective, you have to put the best team that you can. If you look at AHFC (Alaska Housing Finance Corp.), we have one of the top organizations in the state.

When all of the other states were having all of these bankruptcies and all these people were leaving their mortgages, you didn't see that kind of thing happen in Alaska. We have a state organization that does most of the lending on homes and a lot of the commercial property.

They based their decisions upon facts. They didn't just loan anybody who said I want a loan. They didn't loan money without some kind of backup. What you saw was very little foreclosures because we have a strong HFC. Yes, I do want (AGDC) to be a strong organization. Some say you're giving them too much power. We don't say that about HFC.

Petroleum News: So you're OK with giving AGDC that much authority?

Chenault: I'm OK with giving them the authority to see if there is an economically viable pipeline. We give TransCanada access to $500 million, and stand to receive nothing from that other than another study. What I want to see is a strong state organization that has the ability and has the backing to go out not to compete, but to be a viable partner in any project.

see CHENAULT Q&A page 9

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continued from page 8

CHENAULT Q&A

Right now there are assets that AGDC is building that if a pipeline moves forward could be worth hundreds of millions of dollars, whether it's right of ways or an EIS (environmental impact study), which could be very viable for the state to be a partner.

Petroleum News: There was criticism late last year that called the gas line legislation a pipeline to poverty. What are your thoughts on that?

Chenault: It's unfortunate that here are people out there who, if you don't like their particular project, they are going to do everything they can to kill any other project out there. Do I like that this is only a half a bcf a day project? No. But I also know at the end of the day, economics are going to drive this project. We have people who are saying if we can't have a 3.5 or 4 bcf-a-day line, we don't want one.

As a legislator or as a citizen of Alaska, this project is being engineered and designed to stay within the framework of the law (Alaska Gasline Inducement Act). That's what we should do. But what if at some point in the future, things change and maybe they decide there is not a big line going anywhere and this is our only option to invest in: to put together a project that will bring gas to Alaskans? Or at the end of the day, in an open season, if you have sellers who have 2 or 3 bcf a day and they have buyers who want to buy 2 or 3 bcf a day, do I as a legislator say this is not big enough?

Petroleum News: With considering other options in mind, do you support exporting LNG as an option?

Chenault: If the powers that be say we want to build a 3 bcf a-day gas line to Cook Inlet, do you really think the legislators are going to say no. I've never tried to say that I don't like a line going to Canada or I don't like a line going to Valdez or a line going to Cook Inlet. I don't think that I've ever argued against a pipeline going anywhere. Maybe the economics of it or maybe with AGIA how we got there and what we are actually paying for when I knew in my mind the project is not going to work.

Look, TransCanada wants to build a gas pipeline; Alaska wants to build a gas pipeline. I think the Big Three agree that there is a market and we can build a pipeline. Nobody knows how big that pipeline will be until you get to an open season where people can bid on gas.

I think I made a statement at a gas pipeline meeting that if we put a joint of pipeline in the ground for every gas pipeline meeting we've held in this state for the last 30 years, we'd have a fully functioning gas pipeline. **—House Speaker Mike Chenault**

Until we get there, until we get a project on the table, it's a lot of fluff; it's a lot of talk.

It's all talk. It's all talk.

You can't say, people in Korea or people in Japan or the people in Taiwan want to buy our gas, so there is a market there and let's build a pipeline.

If you say I went to Japan, there's a market there, let's build a pipeline. I'm going to say, where's the contract? Show me a 30-year-contract.

I've been to Taiwan a couple of times; I've talked to a number of folks there about our gas. Would they like to have it? Sure. It depends on the cost. But until you get to an open season where you've got buyers and sellers together, we're just talking and we're blowing smoke up people's rear ends.

Petroleum News: Moving to a different subject, what are your thoughts on how things have gone with Arctic development? There was a short drilling season and then problems with the Kulluk being grounded.

Chenault: I don't know all the specifics of what happened with moving the rig when they did. Hindsight is always 20-20. I'm not happy with it. I just talked to Shell and we had a discussion about it, but I'm glad to see they got it off (the rocks) without any environmental damage. I think for the first year in the Arctic, they did as well as could be expected. It's a new frontier. I hope they continue to move forward with it. I don't know what effect the grounding of the Kulluk is going to have on future development as far as this coming year or the year after. We'll wait and see what kind of constrictions and constraints come.

Petroleum News: What about Cook Inlet? They've had some rig problems there as well.

Chenault: Unfortunately, the drill rig shut down in Homer has become not a real problem child, but somewhat of a problem. I think there are some things that they could have or should have been done before they moved the rig over there, but I would rather they take the time to get the drillship in shape to drill in the waters of Cook Inlet. It's a tough basin to explore in. I don't want to see any environmental upsets that pose problems for the fishing industries and the Alaskans who make a living in Cook Inlet. I want them to do it and I want them to do it right, so if it takes more time to get the equipment in the shape that it needs to be, then I'm OK with that. I'm not going to criticize them for making sure their equipment is as safe as it can be in the Cook Inlet. I wish there was more drilling going on and I wish we knew more about the finds they think they have made. But that's going to happen in due time.

Petroleum News: Wrapping up, there are some heavy hitting items before you this session. Can these be sorted out in a year or two?

Chenault: It can be if we want it to happen. It certainly can. It's a matter of whether the Legislature wants to move Alaska forward. Or do we just want to talk about it for another year or two or 20 or 30.

I think I made a statement at a gas pipeline meeting that if we put a joint of pipeline in the ground for every gas pipeline meeting we've held in this state for the last 30 years, we'd have a fully functioning gas pipeline.

Now, I haven't laid out how many joints that would be, but I know I've been to a boatload of meetings on gas pipelines. From where I'm sitting in my driveway, I don't see a joint of pipe being put in the ground anywhere. ●

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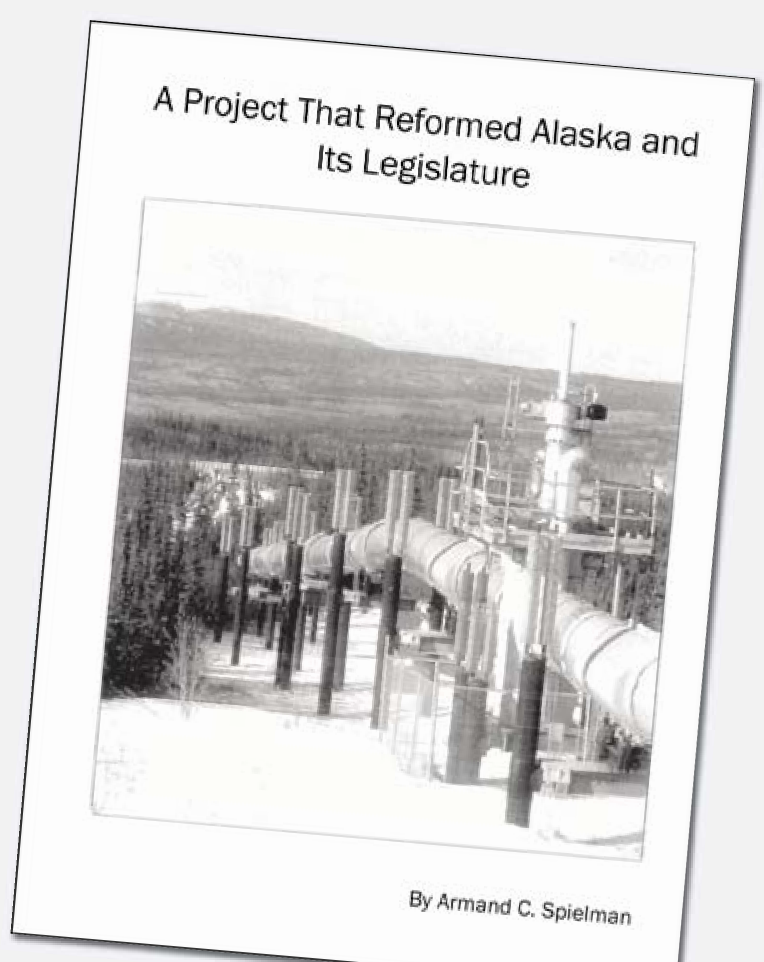

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● NATURAL GAS

AOGCC has say on producing Slope gas

Blessing needed from small Alaska agency on whether natural gas sale in state's best interests; it's been reinjected for 35 years

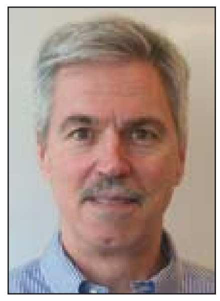
By BILL WHITE

Researcher/writer for the Office of the Federal Coordinator

Among the huge decisions that will determine if a major North Slope gas project gets built is one that will fall on an obscure state of Alaska agency.

Without this agency's blessing, other milestone decisions may be moot, such as North Slope oil producers on constructing the liquefied natural gas project they're studying, or global lenders on fronting multibillions of dollars for construction, or Asian utilities on committing to buy North Slope gas for decades.

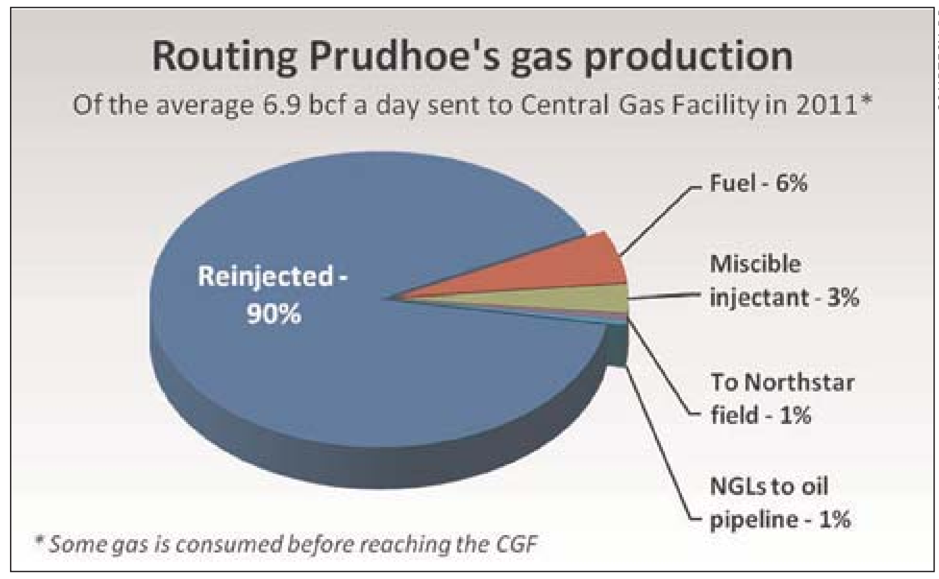
The small state agency that will deliver its own pivotal verdict is the Alaska Oil and Gas Conservation Commission. AOGCC will decide whether it's in the state's best interest to let a huge volume of natural gas leave the North Slope for market. The alternative for the gas that rises up oil wells at the Prudhoe Bay field is to continue injecting it deep underground to push more oil to the surface.



BILL WHITE

Given that the Alaska public for decades has pined for a North Slope gas project, the AOGCC decision might seem like a no-brainer: Let the gas go.

Except for one complicating factor: Gas injection is a strategy practiced at Prudhoe Bay for 35 years with spectacular success. Injecting gas has pushed billions of additional barrels of crude oil from the reservoir — the equivalent of finding several more elephant oil fields on the Slope.



COURTESY BP

This extra oil has extended the output of Prudhoe Bay far beyond original projections and helped make Alaska one of the nation's richest states — not to mention burnishing oil producer bottom lines.

Actually, the commission already has weighed in on how much gas can leave the North Slope. But it set that ceiling in 1977, before Prudhoe Bay even started producing oil, before anyone really knew for sure how the oil field would perform and how realistic the ceiling was.

No one ever has asked for a new look at the 1977 ceiling because a major gas sale never has been imminent.

But before major LNG production can start, the three AOGCC commissioners will need to revisit the ceiling their predecessors set two generations ago. That's because the big Prudhoe Bay producers say they'll likely need up to 50 percent more gas for their LNG project than the ceiling allows.

The commissioners will ponder the relative value of oil versus gas and how many barrels of oil will remain buried in Prudhoe forever when gas production starts. They will mull ways to shore up Prudhoe's underground pressure when less gas is injected. They will crunch the tricky calculus of engineering an aging oil-and-gas field.

And they might even have a couple of wild cards to consider. Can the aging infrastructure of Prudhoe Bay last long enough to get the field's gas out of the ground and piped to market? And on a less scientific and engineering issue, do the oil and gas commissioners want to be the people standing between Alaskans and their gas pipeline project?

The 1977 order

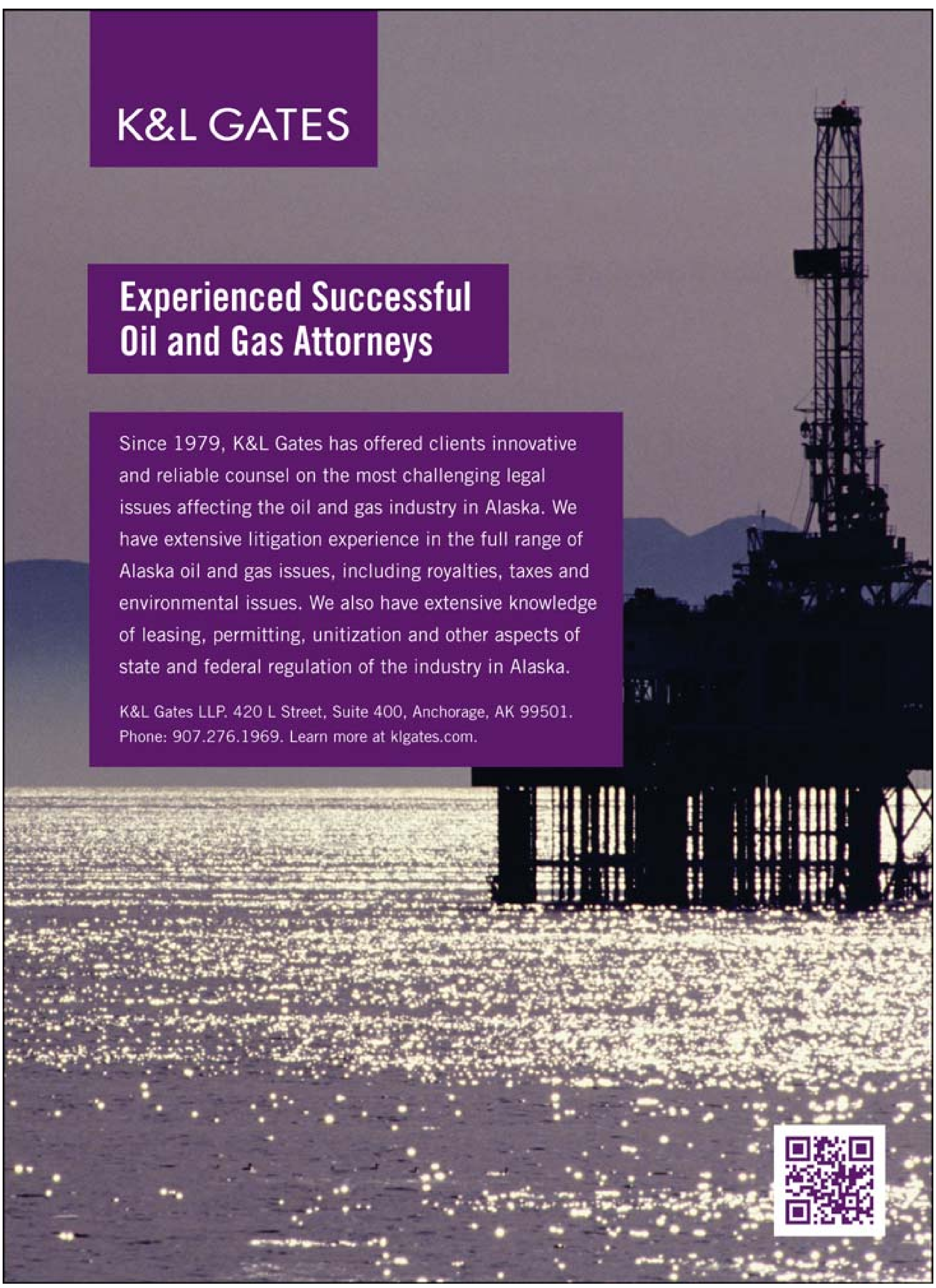
The commission has been around, in one form or another, since Alaska began producing oil and gas more than 50 years ago. Every state with petroleum production has a similar agency that regulates the fields to prevent waste of natural resources.

The Alaska commission is a small, quasi-judicial body charged with making sure the state gets the maximum wealth possible from its oil and gas resources. Three commissioners appointed by the governor lead it — at present they are a lawyer, a geologist and a petroleum engineer.

Considering the millions or even billions of dollars at stake in its decisions, the commissioners and their professional staff are housed in decidedly humble quarters: A one-story building in downtown Anchorage, tucked behind a department store.

Back in 1977, the commission weighed in on how much oil and gas could leave Prudhoe Bay. On June 1 of that year, in Conservation Order 145, the

see SLOPE GAS SALE page 11



continued from page 10

SLOPE GAS SALE

commission decreed that oil companies could produce 1.5 million barrels a day of oil and condensate plus 2.7 billion cubic feet a day of natural gas.

This order came on the brink of Alaska's birth as a major oil producer.

One day earlier, the new 800-mile trans-Alaska oil pipeline got its final weld. Twenty days after the order, producers pumped the first oil production into that pipeline.

As the oil started flowing in June 1977, plans were hatching for a large gas pipeline project, too. The thinking was that gas production would begin five years after oil production — it would take that long to build the gas system.

The commission said the 2.7 bcf per day of gas production would work out this way:

•About 2.2 bcf to 2.3 bcf would be dedicated to the gas pipeline. After cleansing that gas of carbon dioxide and other contaminants, about 2 bcf per day could be piped from the Slope.

•A few hundred million cubic feet would be burned as fuel at the Prudhoe oil field.

•A small amount would become valuable natural gas liquids after processing.

That breakdown worked for the gas pipeline proposed in the late 1970s. But the one under consideration today by the main Prudhoe producers — ExxonMobil, ConocoPhillips and BP — would be at least 50 percent larger, carrying 3 billion to 3.5 billion cubic feet per day.

Plan A: Inject water to boost pressure

In an oil field, pressure moves crude to and up the wells.

The standard technique for producing an oil field like Prudhoe Bay that also contains natural gas is to keep gas in the reservoir as long as possible to provide underground pressure needed to maximize oil production.

Producing gas causes a loss of pressure — and a loss of valuable oil production.

Only at the end of oil production does the gas get produced and sent to market — a process called a field "blow down." This approach provides the maximum oil and the maximum gas production.

If natural gas isn't available to maintain pressure, some substitutes might do, such as nitrogen extracted from the air or water.

Back in 1977, everyone talked about water injections as the answer to maintaining Prudhoe's reservoir pressure after gas production would start in the early 1980s. Water that rises up the wells with oil and gas would be the first pick for injection. But also water from elsewhere if necessary.

In May 1977, the Federal Power Commission weighed in on Prudhoe Bay gas offtake in its recommendation to President Carter on which Alaska gas pipeline project to favor. The commission had conducted more than two years of hearings on a Prudhoe Bay gas project.

"In order to attain a gas sales rate in excess of 2.0 Bcf/d (billion cubic feet a day) — or perhaps even to sustain a 2.0 Bcf/d sales rate over a prolonged period of time without adversely affecting the reservoir — a source water injection program and/or other reservoir management techniques will be required," the commission said. "By employing proper reservoir management techniques, this level of sales can be achieved without having a detrimental effect on a portion of in-place hydrocarbons ultimately recovered."

A month later, the Alaska oil and gas commission said in Conservation Order 145: "Reservoir studies have shown that both produced water injection and source water injection into the Prudhoe Oil Pool should increase oil recovery. Reservoir studies have shown that large scale source water injection will probably be necessary to maximize oil recovery."

The Alaska commission then added a cautionary note: All of these strategies — about how to produce Prudhoe's oil, about the volume of gas available for a gas pipeline, about injecting water to maintain pressure — could be revisited after oil production begins and everybody sees how Prudhoe actually behaves.

"These offtake rates may be changed as production data and additional reservoir data are obtained and analyzed," the order says.

That last sentence means the commissioners can raise or lower the 2.7 bcf a day ceiling depending on what's best for maximizing Prudhoe's production. Even the smaller 500 million-cubic-feet-a-day gas pipeline the state has proposed as a backup to a larger gas pipeline could need AOGCC permission to take gas from Prudhoe.

Plan B: Capture the gas liquids

The gas pipeline project envisioned in the late 1970s was never built. North American gas prices were too low to justify the multibillion-dollar construction cost.

As oil production started in 1977, also up from the wells came a fantastic quantity of natural gas.

Prudhoe is one of the nation's great storehouses of natural gas. Every day Prudhoe and neighboring oil fields produce an average of about 8 billion cubic feet of gas. (Most of it comes from Prudhoe.) That's enough to supply all U.S. households east of the Mississippi River with all the gas they need every day of the years.

Over time, the Prudhoe producers evolved their thinking about what to do with the oil field's gas bounty.

First, with no gas diverted into a pipeline, injecting gas, not water, would be central to keeping the Prudhoe reservoir pressurized. (Produced water does get injected, too.)

By the mid 1980s, the producers also had zeroed in on the money-making potential of a minority slice of the natural gas stream.

Natural gas at the wellhead typically consists of more than just methane, the gas that flows in pipelines and is burned in power plants and household furnaces.

Small amounts of heavier ethane, propane, butane and pentane are mixed in and have a higher market value than methane. By processing the wellhead gas and controlling for temperature and pressure, these other hydrocarbons will liquefy and drop out of the methane.

The producers now aimed to separate out these liquids, which comprise about 7 percent of the gas stream. (Methane is about 80 percent and carbon dioxide about 12 percent.)

see **SLOPE GAS SALE** *page 12*

Pressuring oil to the surface

How does underground pressure bring oil and gas to the surface?

The Alaska Oil and Gas Conservation Commission in 2007 published this analogy of why pressure matters:

"Think about an aerosol container. It starts out with high pressure inside; if you puncture it, it will explode. As you use it, more and more of the fluids — both the active product and the carrier gas — are released and the pressure decreases until, eventually, you push the button and nothing happens. When you shake it, you might be able to hear that there is still hair spray or some other product inside, but you can no longer get it out. At this point the pressure has decreased so that you could even puncture the container and nothing would happen.

"Similarly, in an oil reservoir, the reservoir pressure provides the energy that allows the oil to flow through the reservoir and up the well bore. As fluids are produced, the pressure decreases and the reservoir loses this energy. Eventually, as more and more gas is produced and the pressure continues to drop, there is insufficient energy to drive the oil from the reservoir.

"Typically, operators of oil reservoirs maintain reservoir pressure and energy by re-injecting produced gas and injecting water to replace produced oil. They continue this process until they have recovered all the oil. Then, when no commercially recoverable oil is at risk, they 'blow down' the gas cap. They do this because producing gas from an oil reservoir and not replacing it will result in a decrease of reservoir energy and, therefore, a decrease in oil recovery.

"Another bad thing happens when the reservoir pressure decreases; some oil changes from liquid to gas. The remaining oil becomes thicker. Think about soup cooking; as water evaporates, the remaining liquid becomes thicker. In an oil field, this thickening makes it harder for the oil to flow and, thus, decreases oil recovery. We all know that it is much easier to draw water than molasses up a straw."

—BILL WHITE

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continued from page 11

SLOPE GAS SALE

Marrying chemistry know-how and engineering muscle, they built the biggest, most ambitious gas processing plant in the world to extract the liquids.

Turning gas liquids into money

The Central Gas Facility opened at Prudhoe in 1986. The new strategy was so successful that the producers expanded this plant in 1990, 1993 and 1994 so it could handle more gas, according to BP, which runs Prudhoe Bay on behalf of itself and the other producers.

The plant is a giant — a quarter-mile long on one side. The 10-story compressor module weighs 5,400 tons.

The plant can produce up to 100,000 barrels of natural gas liquids daily, although in recent years production has been about half of that, according to AOGCC figures. Since its inception it has processed more than 600 million barrels of gas liquids.

The producers put these liquids to use in three ways:

Some gas liquids flow with crude oil through the trans-Alaska pipeline to market.

COURTESY BP

Prudhoe Bay Central Gas Facility

Prudhoe Bay gas

Typical composition of produced Prudhoe gas

Methane	80%
Carbon dioxide	12%
Ethane	5%
Propane	2%
Butane	0.2%
Pentane	0.04%
Hexane & heavier	0.02%
Nitrogen	0.6%

Source: State of Alaska

Some get blended into a special cocktail called "miscible injectant" used to coax more oil from Prudhoe and a handful of neighboring reservoirs.

Some get routed to the nearby Kuparuk River field for use in miscible injectant there.

The remaining gas — actually the bulk of the produced gas — gets pumped back underground to bolster Prudhoe's pressure.

Here's a brief look at these uses of natural gas liquids.

Gas liquids in the oil pipeline

Oil and natural gas are called hydrocarbons because they're comprised of hydrogen and carbon atoms. The more carbon atoms, the heavier the hydrocarbon and the more heat a given unit can produce. In general, more heat means more value.

Methane has one carbon atom, ethane two, propane three, butane four, etc. With enough carbon atoms you get crude oil. Another feature of these different hydrocarbons: The more carbon atoms, the higher the ambient temperature that will keep them in liquid form rather than as vapors.

The heaviest natural gas liquids — butane, pentane and hexane — will remain liquid at the same temperatures as crude oil in the trans-Alaska oil pipeline. So they can be, and are, sent to market at the same time in the same pipe.

Last year, the producers extracted an average of 50,000 barrels a day of natural gas liquids from the gas stream, according to AOGCC figures. Of that total, about 30,000 barrels a day of the heavier gas liquids flowed down the oil pipeline, according to BP. That was roughly 5 percent of what the oil pipeline carried.

Miscible injectant

Some carbon dioxide, methane, ethane and propane get blended into miscible (mixable) injectant used at a variety of North Slope fields to boost oil production.

At Prudhoe, BP pumps the miscible solvent under high pressure into the oil column's periphery.

The injectant mixes with oil stubbornly clinging to rock, relaxing the oil's grip. BP then pumps in water to flush the oil toward wells.

When the MI plant was last expanded, in 1999, the industry estimated the injections would wrest an extra 50 million barrels of oil from Prudhoe over time.

Miscible use at other fields

Some gas liquids get shipped to the Kuparuk River field west of Prudhoe.

ConocoPhillips, which runs the big oil field there, makes miscible injectant from a blend of Prudhoe liquids, Kuparuk liquids and other Kuparuk gas production.

Some smaller fields near Prudhoe also use miscible injectant, including the Orion, Polaris, Borealis, Aurora and Point McIntyre fields, BP said. (These fields are produced through the Prudhoe Bay facilities.)

Further, BP transports some Prudhoe gas to its Northstar field north of Prudhoe for use as fuel and injection gas that is miscible, the company said.

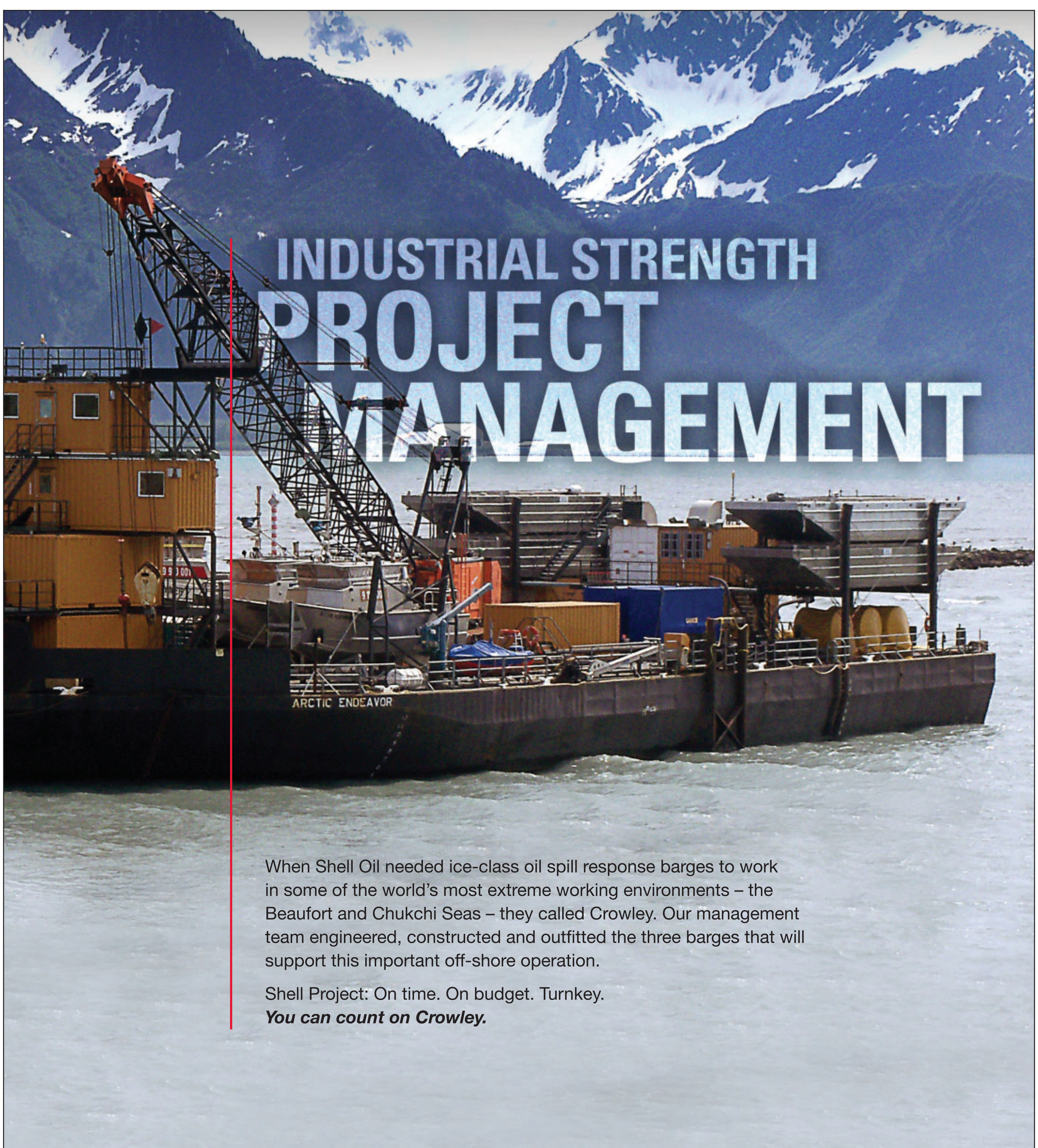
The virtues of injecting gas

In the absence of a gas pipeline, the shift to, and expansion of, natural gas liquids production at the Central Gas Facility has occurred with the blessing of the Alaska oil and gas commission.

In 1987, about a year after the Central Gas Facility started work, C.V. "Chat" Chatterton, then the commission chairman, extolled the wisdom of keeping Prudhoe gas at Prudhoe.

Already it was clear that more oil was being produced than expected thanks to gas injections, Chatterton said at a state-federal

see SLOPE GAS SALE page 13



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continued from page 12

SLOPE GAS SALE

workshop on "Alaska Gas Utilization."

"The gas is now serving a useful purpose by staying at home and prolonging the time that the pool's crude oil allowable production rate can be maintained. Certainly, the state of Alaska's general fund is thankful. ... And I suspect that the owners of the gas, the Prudhoe Bay Unit participants, are equally thankful that oil production has yet to decline," Chatterton said.

"Just maybe, events to date provide a clue as to the use for ANS (Alaska North Slope) gas that will realize its greatest value. And that use is enhancement of crude oil production from oil fields north of the Brooks Range," he continued.

As for the new miscible injectant program, Chatterton said, "The economics ... are highly favorable and considered to be the lowest cost option for the North Slope gas utilization."

Industrial-strength injections

Gas liquids aside, the main show for Prudhoe Bay natural gas, as Chatterton noted, involves injecting it back into the field under ferocious pressure.

Since 1977 more than 63 trillion cubic feet of gas has been produced. About 56 tcf of that has been reinjected.

It's as if every molecule of gas originally in place at Prudhoe has been produced and injected twice in the past 35 years.

Besides the injected gas, about 6 tcf has been used up since 1977, mostly to fuel the oil fields, but also by the oil pipeline and two small utilities in the neighboring town of Deadhorse, according to state statistics.

Last year, Prudhoe's Central Gas Facility processed an average of 6.9 bcf a day. Of that, about 700 million cubic feet was used to make miscible injectant, burned as fuel, exported to the Northstar field or sent down the oil pipeline as liquids, BP said. (Other fields handle their own gas production. The entire North Slope produced about 8 bcf a day of gas last year.)

That left about 6.2 bcf a day for injection at Prudhoe. BP pipes this gas next door to the Central Compression Plant, a beast of an industrial plant itself. That plant does just what its name implies: It super-compresses the gas molecules into tight formation — roughly 4,000 pounds of pressure per square inch — and punches them down into the gas cap that overlies the Prudhoe oil column and pressurizes it.

Because less gas is injected than is produced, Prudhoe has lost some of its underground pressure over time.

When production started in 1977, the underground pressure was 4,335 pounds per square inch. The pressure today has stabilized at about 3,300 psi, BP said.

The longer that produced natural gas stays at Prudhoe rather than getting sent down a pipeline for an LNG project, the more oil that will be produced.

In 1997, two state Revenue Department officials examined how much Prudhoe oil would be lost when major gas sales begin. For purposes of their study, they assumed a 1.9 bcf-a-day gas pipeline project would be completed in 2005 and would ramp up to full capacity by 2010.

They concluded a loss of 259 million barrels of oil production would result through 2029.

The authors, Roger Marks and Greg Bidwell, noted that the oil loss would be lower if the gas pipeline started up later or the ramp up was slower.

In 2007, still with no gas pipeline, a National Energy Technology Laboratory report forecast a smaller loss of oil due to a gas pipeline carrying 3.44 bcf a day starting in 2015.

The study predicted 133 million barrels lost from Prudhoe over time. But that loss would be offset by 400 million barrels of new oil and condensate production from the Point Thomson field east of Prudhoe, a field that would be developed to tap its gas for a gas pipeline, the authors said.

'No trivial task'

The three Alaska oil and gas commissioners are well aware they could be asked to allow a significant amount of gas to leave Prudhoe Bay via a gas pipeline project.

To get ahead of the game, in 2005 they held public hearings on the old 2.7 bcf-a-day offtake ceiling. At the time, the Prudhoe producers were talking about a pipeline that could carry 4.3 bcf a day, expandable to 5.6 bcf.

Those hearings led the commission to study how much oil would be lost under different gas-offtake scenarios. The producers cooperated with the study, which was completed in 2007 and has been kept confidential.

"The Gas Offtake Study found insufficient information on which to justify increasing the offtake rate above 2.7 bscfd, but concluded that an early, high rate gas sale could result in the loss of a substantial volume of hydrocarbons, but even greater volumes could be lost if gas sales are too delayed," the commission said in a summary at the time.

The commissioners found it premature for the producers to provide a detailed "depletion plan," in advance of major gas sales, "that insures a greater ultimate recovery and prevents waste of oil and gas." But the producers need to demonstrate to the commission "that they are implementing near-term strategies to maximize oil recovery prior to gas sales."

Although the commission's 2007 offtake study is confidential, the agency that year published a series of short papers that outlined the situation.

The papers noted that generally the longer a gas-pipeline project is delayed, the less oil production that would be lost.

But Prudhoe Bay is an old oil field in a harsh climate with high maintenance costs. "The longer that gas sale is delayed, the greater the risk of well and facilities failure resulting in premature field shutdown," an AOGCC reservoir engineer wrote in a memo to the commissioners.

Another paper elaborates on aging Prudhoe Bay equipment. "The later in time that the gas is produced, the higher the costs will be to operate, repair and replace equipment and, thus, the sooner the gas will become uneconomical to produce and the more gas that will be left stranded."

In meeting their responsibilities, the paper continues, the commissioners "must be cognizant of the balance between oil recovery optimization and gas recovery optimization.

"This will be no trivial task." ●

Editor's note: This is a reprint from the Office of the Federal Coordinator, Alaska Natural Gas Transportation Projects, online at www.arcticgas.gov/small-alaska-agency-has-say-producing-north-slope-gas.

Tapping Prudhoe's relic oil

Injections also help produce so-called "relic oil" stranded in the gas cap after most of Prudhoe's oil migrated lower in the reservoir over many millennia.

BP estimates the gas cap holds 1 billion barrels of relic oil. The company likens this oil to "the film of sauce that remains on the sides of (a) sauce bottle when you can no longer get any more out even when it's upside down."

Injected methane vaporizes relic oil so that it will come to the surface when the gas is produced again.

—BILL WHITE

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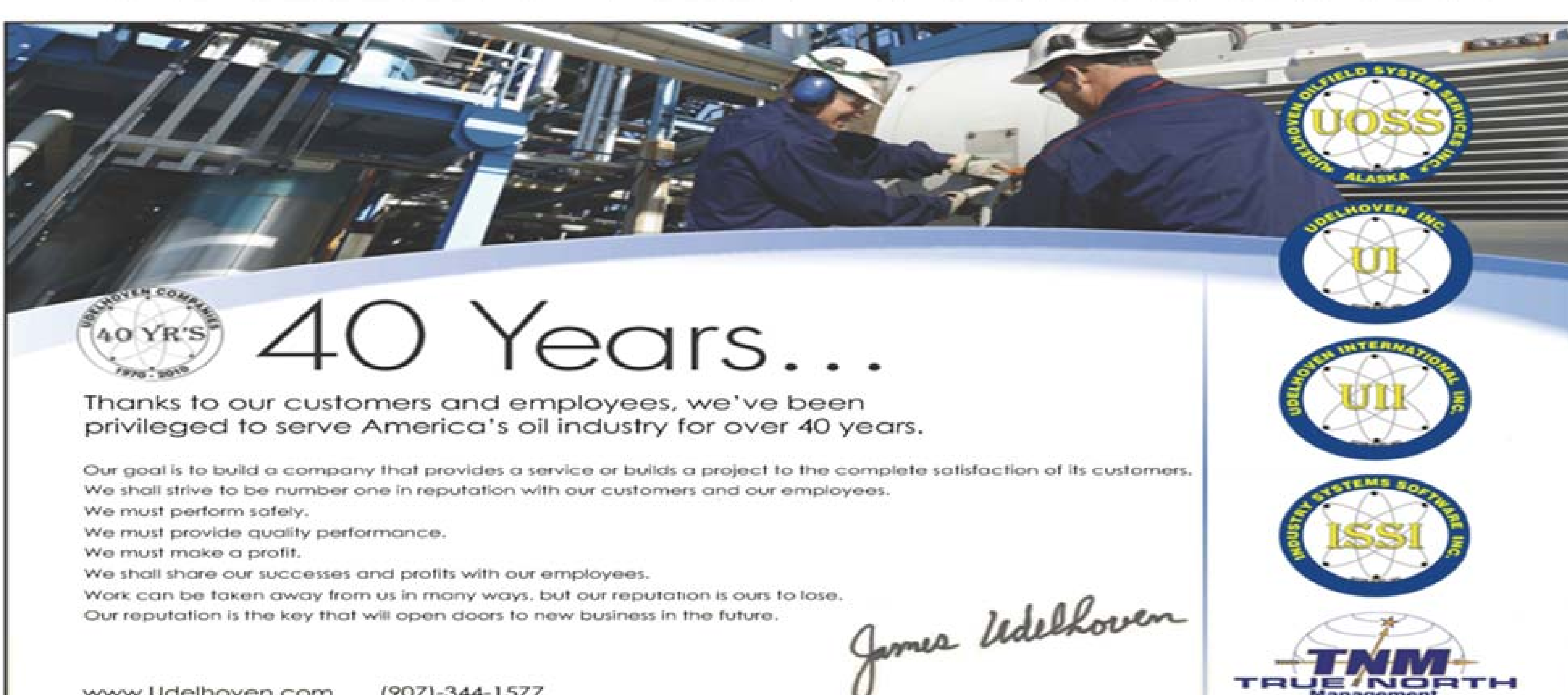

● FINANCE & ECONOMY

Prudence rules Canada's upstream

By GARY PARK
For Petroleum News

Spending among Canada's E&P companies in 2012 and the budget plans for service companies are reinforcing the upstream industry's cautionary outlook.

Of the numbers emerging from about half of the top 100 producers for last year, 27 have added to their original budgets and 26 have made cuts.

Influenced by those trends, the service sector appears destined to pull back from its 2012 investments, figuring the rigs and related equipment are more than enough to carry the industry through this year.

As 2012 wound down, Encana led the spending increases in dollar terms at US$600 million, followed by oil sands player MEG Energy at C$380 million and Vermilion Entergy at C$315 million for its interests which span the globe, plus two key Bakken players, Crescent Point Energy up C$300 million and PetroBakken, posting a C$275 million increase.

The heaviest cuts were made by gas-weighted companies, led by Canadian Natural Resources at C$750 million, Talisman Energy at US$400 million, Penn West Petroleum at C$250 million and Progress Energy Resources at C$195 million.

C$580 million decline

The overall count pointed to a decline of about C$580 million from the original budget targets of C$60.7 billion.

The latest cash flow figures covering the first nine months of 2012 showed the biggest gainers were Imperial Oil at C$558 million, Cenovus Energy C$521 million and Suncor Energy C$393 million.

Overall, the 100 producers posted a slight decline for the nine months at C$38.63 billion compared with C$38.94 billion in the same period of 2011.

But the bottom line numbers for the third quarter explained the uneasy mood within the industry, with total net income for the 100 companies off 74 percent at C$1.63 billion, compared with C$6.37 million for a year earlier, with Encana reporting the largest decrease, falling US$459 million to US$1.24 billion.

The pace-setting production gains for the third quarter were booked by Crescent Point, up 27,373 barrels of oil equivalent per day, Cenovus 24,690 boe, ConocoPhillips Canada, which is in a 50-50 oil sands joint-venture with Cenovus, 20,833 boe and Pengrowth Energy 19,716 boe.

On the oil and liquids front, Canadian Natural led the pack, boosting its third-quarter output by 65,268 barrels per day to 469,168 bpd, followed by Cenovus at 37,857 bpd, ConocoPhillips at 30,000 bpd, Crescent Point 24,395 bpd and Pengrowth 10,415 bpd.

Cuts in service sector

In the service sector, some companies are engaged in drastic budget-cutting as some divert spending from growth capital to maintenance spending.

Precision Drilling slashed its 2013 program to C$485 million from its original 2012 budget of C$1.14 billion, which was later trimmed to C$920 million.

Brian Purdy, an oilfield services analyst for Global Hunter Securities, said the budgets are reflecting unchanged activity levels, suggesting that the equipment added in 2012 is probably sufficient to meet the fracturing and drilling demands expected this winter.

Western Energy Services mirrored that view, targeting C$60 million for 2013 after spending aggressively on rigs over the past two years, although it is counting on its 44 deep-drilling rigs being fully booked through winter.

Ken Mullen, president of Savanna Energy Services, which has set a flat program of C$107 million for the year, said the challenge facing most producers is to get a fix on what lies ahead after the second quarter.

Mark Salkeld, president of the Petroleum Services Association of Canada, said service companies are fairly confident that can ride out the next year or so without adding new field equipment.

However, in a research note, invest-

see **CANADA'S UPSTREAM** *page 15*

EXPLORATION & PRODUCTION

Two coastal areas open for tundra travel

Both the eastern and western coastal areas of state land on the North Slope are now open for winter tundra travel. The Alaska Department of Natural Resources, or DNR, said Jan. 8 that the eastern coastal area of state land on the North Slope was open for winter tundra travel. Conditions within the area have met the required parameters of snow depths of at least six inches and soil temperatures below minus 5 degrees C at a depth of 30 centimeters, DNR said.

Jan. 9 DNR said the western coastal area had met the snow and temperature criteria and was also open.

Snow and frozen ground protects the Arctic tundra from damage in the winter, allowing companies conducting off-road exploration or development activities on the North Slope to use vehicles that are not tundra-certified. DNR has established parameters for snow depths and ground temperatures that have been demonstrated to provide adequate ground protection. However, operators still need permits from DNR if they plan to use vehicles in off-road situations.

The lower and upper foothills areas remain closed.

—PETROLEUM NEWS

● FINANCE & ECONOMY

EIA projects falling crude oil prices

Energy Information Administration's January Short-Term Energy Outlook projects Brent at $105 this year, down from $112 in 2012

By KRISTEN NELSON
Petroleum News

The U.S. Energy Information Administration is projecting that the Brent crude oil spot price will average $105 per barrel this year, down from $112 per barrel in 2012, with a further drop to $99 per barrel forecast for 2014, reflecting increased production from non-Organization of the Petroleum Exporting Countries.

The discount of West Texas Intermediate crude oil to Brent, which averaged $18 per barrel last year, is projected to be $16 per barrel this year and $8 in 2014 because of planned new pipeline capacity which will lower the cost of moving oil from the Midcontinent to the Gulf Coast, EIA said.

WTI averaged $94 last year and EIA expects it to average $90 this year, increasing to $91 in 2014.

U.S. crude oil production, which averaged 6.4 million barrels per day last year, an increase of 800,000 bpd from 2011, averaged 7.3 million bpd this year and is expected to increase to 7.9 million bpd in 2014, "which would mark the highest annual average level of production since 1988," EIA said.

"Central to this projected growth will be ongoing development activity in key onshore basins," with drilling in tight oil plays in the Williston, Western Gulf and Permian "expected to account for the bulk of forecast production growth over the next two years."

Non-OPEC growth up

Continued growth in U.S. tight oil and Canadian oil sands production accounts for about two-thirds of the expected increase in non-OPEC production growth, projected to grow by 1.4 million bpd this year and by 1.3 million bpd in 2014.

OPEC members are expected to continue to produce at least 30 million bpd over the next two years, EIA said,

OPEC surplus capacity, concentrated in Saudi Arabia, was at 2.3 million bpd in December, "relatively tight by historical standards," and is expected to increase to 3.1 million bpd this year.

As U.S. production increases, net liquid fuel imports, including crude oil, have been falling.

> *U.S. crude oil production, which averaged 6.4 million barrels per day last year, is projected to grow by 800,000 bpd, averaging 7.3 million bpd this year and 7.9 million bpd in 2014, "which would mark the highest annual average level of production since 1988."*
> **—U.S. Energy Information Administration**

U.S. net liquid fuel imports peaked at 12.5 million bpd in 2005, EIA said, declining to 7.5 million bpd in 2012, and are expected to decline to an average of 6 million bpd by 2014.

The share of total U.S. consumption met by net liquid fuel imports peaked at more than 60 percent in 2005 and fell to an average of 40 percent in 2012, EIA said, and is expected to average 32 percent in 2014 "because of continued substantial increases in domestic crude oil production."

U.S. natural gas

Despite relatively low natural gas prices — which averaged $3.34 per million Btu at the Henry Hub in December, and are expected to average $3.74 per million Btu next year (compared to $2.75 in 2012) and $3.90 in 2014 — EIA said domestic natural gas production is expected to grow, "driven largely by onshore production in shale areas."

Production has been rising despite a decrease in the natural gas rig count, which Baker Hughes pegged at 431 on Dec. 28, compared with 811 at the start of the year. EIA said the oil rig count has also declined in recent months, although that decline has been smaller.

"The declines in rig counts, coupled with continued production growth, suggest increases in rig efficiency, which will maintain production levels going forward," EIA said.

Domestic production is continuing to replace pipeline imports from Canada and liquefied natural gas imports, and EIA said it expects gross pipeline imports to stay flat this year, while LNG imports are expected to stay at minimal levels, since higher prices for LNG have made the U.S. a market of last resort.

U.S. inventories of working natural gas in storage remain at high levels after setting an all-time weekly record in November, EIA said, with withdrawals limited so far this winter because of warmer-than-normal December temperatures. ●

Contact Kristen Nelson at knelson@petroleumnews.com

continued from page 14

CANADA'S UPSTREAM

ment banker Peters & Co. said the conclusion of the Encana joint venture with a unit of PetroChina along with the CNOOC takeover of Nexen and the Petronas acquisition of Progress Energy Resources, are a positive sign for the service sector, especially in the Duvernay and Montney formations.

But it acknowledged that uncertainty still persists because of concerns over wide crude oil price differentials, natural gas liquids pricing and gas fundamentals.

The firm said that mood is likely to stretch in this year's second half, delaying the chances of a recovery in 2014. ●

Contact Gary Park through publisher@petroleumnews.com

● EXPLORATION & PRODUCTION

A bittersweet year for Shell in Alaska

In 2012 company finally starts drilling in the Arctic OCS, while a string of glitches and the Kulluk grounding grab public attention

By ALAN BAILEY
Petroleum News

For Shell, 2012 was the year in Alaska in which the company finally saw drill bits turn in its oil prospects in the Beaufort and Chukchi seas after a six-year effort to start its Arctic outer continental shelf exploration drilling program. But a series of snafus and a major grounding incident with the company's Kulluk floating drilling platform also took the gloss off the year's achievements, giving new ammunition to those who view oil drilling in the Arctic offshore as unacceptably risky.

At the beginning of the year there were signs that, after battling a constant headwind of litigation and permitting hurdles for several years, Shell's ambition of starting a new program of Arctic Alaska offshore drilling was finally going to bear fruit.

Following the conclusion of an appeal against the 2008 Chukchi Sea lease sale in which Shell purchased its Chukchi Sea leases, the Bureau of Ocean Energy Management, or BOEM, had affirmed the validity of the sale in October 2011. And in December 2011 BOEM approved Shell's Chukchi Sea exploration plan, having already approved the company's Beaufort Sea plan in August 2011.

Following the Deepwater Horizon disaster in the Gulf of Mexico, Shell had committed to the use of blowout preventers with double shear rams, and to the development of two new systems for its Arctic venture: a well capping system that could close a subsea well in the event of a blowout preventer failure, and an oil containment system that would gather any oil leaking from an out-of-control well.

And, by the time that the drilling season drew to a close at the end of October the two rigs had completed the top holes sections — the upper 1,400 to 1,500 feet — of one well at Burger and one well at Sivulliq, in preparation for completing the wells in 2013.

The company planned to deploy the capping and containment systems on a barge, near a midpoint between the Beaufort and Chukchi Sea drilling operations. The availability of these systems became part of Shell's government-mandated oil spill prevention and response plans.

Several wells planned

Shell hoped to drill up to two wells in the Sivulliq and Torpedo prospects in the Beaufort Sea and up to three wells in the Burger prospect in the Chukchi Sea in 2012. The Sivulliq and Torpedo prospects lie on the west side of Camden Bay, offshore the North Slope, to the east of Prudhoe Bay. Sivulliq, previously known as Hammerhead, contains a known oil accumulation. Burger, a structure 25 miles in diameter, lies about 80 miles offshore the western end of the North Slope and is known to contain a major natural gas pool — Shell has conducted a 3-D seismic survey over Burger and thinks that there is a high probability of finding oil in the prospect.

Shell planned to use the drillship Noble Discoverer in the Chukchi Sea and the floating drilling platform, the Kulluk, in the Beaufort Sea.

In December 2011 Superior Energy Services began work in Bellingham, Wash., on retrofitting the Arctic Challenger, an Arctic-class barge, to hold Shell's new containment system. And in February 2012 the Bureau of Safety and Environmental Enforcement, or BSEE, approved Shell's oil spill contingency plan for the Chukchi Sea.

Also in February, two appeals went into the U.S. Court of Appeals for the 9th Circuit: one appeal against BOEM approval of Shell's Chukchi Sea exploration plan, and another appeal against the Environmental Protection Agency's air permit for the Noble Discoverer. An appeal against approval of Shell's Beaufort Sea exploration plan was already in progress in the same court.

Moving ahead

At the end of February, in anticipation of further litigation, Shell took pre-emptive action by asking the federal District Court in Alaska to rule that BSEE had correctly approved the Chukchi Sea oil spill response plan. The company also asked for, and was subsequently granted, a restraining order against environmental activist organization Greenpeace, prohibiting Greenpeace from obstructing Shell's Arctic operations.

In March BSEE approved Shell's Beaufort Sea oil spill contingency plan and Shell asked the District Court to add this plan approval to the existing lawsuit requesting confirmation of the legality of the Chukchi Sea response plan.

And in March Shell took delivery of the MV Aiviq, a brand new 360-foot, 21,776-horsepower, Arctic-class anchor handler.

In late April Shell announced that it was starting to mobilize its Arctic drilling fleet. Then, at the beginning of May, the National Marine Fisheries Service issued incidental harassment authorizations, allowing the unintended minor disturbance of whales and seals during Shell's drilling operations — Shell promptly filed another lawsuit request court confirmation of the validity of the authorizations.

Meantime, a nearly $100 million upgrade to the Kulluk was nearing completion, fitting the vessel with new emissions control equipment and with a new system for recovering drilling mud and cuttings.

In May the 9th Circuit court rejected the appeals against both the Beaufort Sea and the Chukchi Sea exploration plans.

Chukchi ice delay

Everything appeared to be progressing to plan for Shell until early July, when the company announced that unusually heavy sea ice in the Chukchi Sea was delaying the start of the drilling program. The company had stationed its vessels at Dutch Harbor in the Aleutian Islands, in hopes of moving the fleet north through the Bering Strait as soon as possible.

At about the same time it became apparent that the retrofit of the Arctic Challenger with the new containment system had not been completed. And without the Arctic Challenger deployed, BSEE would not issue Shell's drilling permits.

At the end of June Shell, having conducted some new emissions tests on the Noble Discoverer and on the upgraded Kulluk, informed the Environmental Protection Agency that the exhaust systems on the two vessels no longer fully complied with the stipulations in the vessels' air permits. Under the terms of its air permit the Kulluk would be able to operate as planned, pending an EPA decision on the change request. But, with the Kulluk having a major permit, Shell needed an EPA compliance order before the Discoverer could go into operation.

The EPA did in the event issue the required compliance order.

On July 14 the Noble Discover, still positioned at Dutch Harbor, dragged its harbor and drifted close to the shore before being towed back into position by a tug.

Ice finally clears

Several weeks passed, with Shell's

see SHELL IN ALASKA page 17

continued from page 16

SHELL IN ALASKA

fleet still on hold at Dutch Harbor. The Chukchi Sea ice cleared, but the Arctic Challenger remained in dock in Bellingham, awaiting completion of the containment system retrofit and subsequent vessel certification by the U.S. Coast Guard.

Around the beginning of August three vessels from Shell's fleet departed Dutch Harbor for the Chukchi and Beaufort seas to start preparing Shell's drilling sites. But with the delayed start to the drilling season Shell said that it was cutting back its drilling expectations to just one complete well in the Chukchi Sea and one complete well in the Beaufort, with the possibility of also drilling some top sections of other wells.

On Aug. 20 the Kulluk departed Dutch Harbor for the Beaufort Sea and on Aug. 25 the Noble Discoverer left for the Chukchi Sea. On Aug. 30 BSEE issued a drilling permit, allowing the drilling of the top section of Shell's first Burger well, with drilling limited to depths substantially above any potential hydrocarbon bearing zone. Permission to drill into hydrocarbons would have to wait until the deployment of the Arctic Challenger.

The Noble Discoverer finally started drilling at Burger at 4:30 a.m. on Sept. 9, at which time the Kulluk was in a holding position in the Beaufort Sea, waiting for the end of the annual subsistence whale hunt.

On Sept. 10, less than two days after the start of drilling, Shell had to move the Noble Discoverer off the well site, as a 12-mile by 30-mile ice floe started drifting towards the drilling site.

On Sept. 17 Shell announced that the containment dome on the Arctic Challenger had been damaged during testing of the containment system and that, consequently, the company would only drill the top hole sections of wells in 2012, a plan that BSEE subsequently approved.

Shell later said that the problem with the containment dome test was the result of an electrical fault that had caused a valve to open and the dome to descend rapidly in the sea. According to internal BSEE emails obtained by a Seattle radio station, the top of the dome was "crushed like a beer can."

Top hole sections drilled

Drilling eventually restarted at Burger, while the Kulluk moved into action in early October, starting the drilling of a top hole at Sivulliq. And, by the time that the drilling season drew to a close at the end of October the two rigs had completed the top holes sections — the upper 1,400 to 1,500 feet — of one well at Burger and one well at Sivulliq, in preparation for completing the wells in 2013.

Shell's fleet subsequently returned to Dutch Harbor for demobilization.

The company put on a brave face over its curtailed drilling program, saying that the drilling of the top holes involved more than half of the time required to completely drill the wells. The 2012 operation had involved the successful deployment of a large number of assets and the rotation of thousands of employees to the Arctic, the company said.

But Shell's difficulties in 2012 were far from over.

A loud bang from the Noble Discoverer caught people's attention at Dutch Harbor when the drilling vessel returned to the port. It turned out that an engine on the vessel had backfired, with the crew having to extinguish a resulting small residual fire.

Discoverer in Seward

The Noble Discoverer transited to Seward on the Kenai Peninsula, with the intent of moving from there to the U.S. West Coast for maintenance. However, upon arrival in Seward the crew reported a problem with the vessel's propulsion system. Coast Guard inspectors called to investigate the problem spotted deficiencies in some crew safety and pollution prevention systems. The Coast Guard placed a detention order on the vessel while essential repairs were carried out. And Noble Corp., the owner and operator of the drillship, said that it had found some non-compliance issues, including the possible unauthorized discharge of collected water outside the period of drilling operations.

With the propulsion system not yet repaired, the Noble Discoverer remains in Seward. Shell says that it plans to tow the vessel to the West Coast once it has assembled the necessary assets to carry out the towing operation.

Meantime, with Shell having decided to have maintenance and repair work done on the Kulluk on the U.S. West Coast in preparation for the 2013 drilling season, the Aiviq set out from Dutch Harbor on Dec. 21 with the Kulluk under tow, heading for the Seattle area and following a route paralleling the coastline.

Kulluk encounters storm

On Dec. 27 during a raging storm in the Gulf of Alaska the hawser connecting the Aiviq and the Kulluk broke. A few hours later problems compounded when all four of the Aiviq's engines failed about 60 miles south of Kodiak Island. Despite heroic efforts by the U.S. Coast Guard, the crews of Shell's vessels and a tug deployed from Valdez, the Kulluk, carried north by a severe gale, ran aground on the shore of Sitkalidak Island to the southeast of Kodiak Island on Dec. 31.

By the time of the grounding a full-scale emergency response had been initiated and a unified command formed to manage the response effort. The incident management team succeeded in refloating the Kulluk on Jan. 7 and the drilling platform is now anchored in Kiliuda Bay on the south side of Kodiak Island, undergoing inspections that will enable a decision on when and how to move the vessel for repair.

So far no evidence of any environmental impact from the grounding has been found and there have been no significant injuries. As responsible party, Shell is footing the bill for the emergency response effort and the recovery of the Kulluk. The Coast Guard has initiated an investigation into the incident and Shell has said that it will participate in the investigation and implement any lessons learned.

Environmental organizations, all of which have strenuously opposed Shell's plans for oil exploration on the Arctic continental shelf, have cited Shell misfortunes, the Kulluk incident in particular, as evidence that oil drilling in the remote and challenging Arctic offshore environment poses too high an environmental risk to be acceptable.

Shell, for its part, has consistently claimed that the types of well it has started drilling in the Beaufort and Chukchi seas will prove very straightforward to complete and pose little risk of an oil spill. The company has assembled a self-contained oil spill response fleet which the company says is capable of dealing an oil spill in unlikely event of a drilling accident. And government regulators, in issuing Shell's permits, have tended to support Shell's position. ●

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● NATURAL GAS

Gas challenge for Cook Inlet utilities

With days of abundant supplies gone, storage developed to meet winter deliverability, but long-term supply availability an issue

By ALAN BAILEY
Petroleum News

In January 2009 a severe cold snap in Southcentral Alaska coupled with the failure of two gas compressors in Cook Inlet gas fields caused the rate at which gas could be supplied to local gas and power utilities to come close to falling below the rate at which gas was being consumed. In some ways this event marked the beginning of a new era for utility energy in Southcentral, with once over-abundant gas supplies from the Cook Inlet basin finally dropping to levels close to the level of gas demand, as production declines from the aging Cook Inlet gas fields.

With Southcentral residents and businesses being dependent on natural gas for heating their buildings and for generating electricity, the sustenance of adequate gas supplies during the cold sub-Arctic winters is critical to life in the region. And, unlike elsewhere in North America, the Southcentral utility gas supplies are isolated, with no opportunity to supplement local supplies with supplies from elsewhere.

Events in 2012, some three years after that 2009 incident, saw a continuing tightening of the gas supply situation coupled with several moves to try to head off a mounting gas supply crisis.

Supply and deliverability

The evolving gas situation needs be viewed from two distinct but related perspectives: the total supply in terms of the total volume of gas available over the course of a year, and the deliverability, the rate at which gas can be flowed to gas consumers at any particular time. The crisis in January 2009 was one of gas deliverability, although it also flagged pending problems on the supply side.

And by 2012 the deliverability situation had hit the limit of what could be achieved from the existing gas infrastructure.

PRA said that the essential problem is that, despite the resurgence of interest in Cook Inlet gas exploration and development, gas drilling is not happening fast enough to sufficiently stem the gas supply decline.

So, with gas deliverability heading for a shortfall in the winter of 2012-13, Enstar Natural Gas Co., the main Southcentral gas utility had been spearheading the development of gas storage facilities for utility use. By warehousing summer-produced gas for use in the winter, a storage facility can bolster winter deliverability.

For several years the gas producers had been operating their own storage facilities, to manage gas deliverability needs under their gas supply contracts. But, with contracted deliverability commitments starting to fall short of what would be required, the time had come for the utilities to establish their own storage arrangements.

CINGSA completed

Cook Inlet Natural Gas Storage Inc., or CINGSA, a subsidiary of Enstar's parent company, fast tracked the development of a new storage facility, using depleted gas reservoir sands in the Cannery Loop gas field, immediately south of the city of Kenai on the Kenai Peninsula.

Construction of the CINGSA facility was completed by the spring of 2012, with the facility taking its first deliveries of gas April 1. The three main gas and power utilities serving the Anchorage area — Enstar, Chugach Electric Association and Municipal Light & Power — had all booked space in the facility to ensure the availability of sufficient winter gas, with gas delivery from CINGSA forming an essential component of utility gas supply portfolios.

To ensure winter gas deliverability the utilities need to ensure not only that they have a sufficient gas supply but also that the gas can be transported at a sufficient speed through the Southcentral gas pipeline network — gas transportation has become something of an issue in recent years as the center of gravity of gas production has tended to shift from the west side of Cook Inlet to the Kenai Peninsula, on the east side. The opening of the CINGSA facility on the peninsula has put further pressure on a pipeline network, the layout of which has remained fairly static amid a changing gas production scene.

Bi-directional flow in CIGGS

A significant breakthrough in the gas shipment scene came in January 2012, when the Regulatory Commission of Alaska approved bi-directional flow in the Cook Inlet Gas Gathering System, known as CIGGS. CIGGS, a gas pipeline system that runs under the middle of the upper Cook Inlet, was built several decades ago to ship gas from the oil and gas fields on the west side of the inlet to the gas infrastructure on the east side. But with Chugach Electric's power station at Beluga, on the west side of the inlet, now wanting to be able to ship some of its gas supplies from the Kenai area, with CINGSA coming on line and with concerns about maintaining adequate gas flows through a major Enstar gas line from the Beluga area into the Matanuska-Susitna Valley, enabling gas to flow east to west through CIGGS had become a priority for gas shippers.

Modifications to CIGGS to enable bi-directional flow included the installation of a new gas compressor on the Kenai Peninsula and modifications to the pipeline's gas metering system.

From the perspective of total gas supplies, tax incentives introduced by the Alaska Legislature coupled with a market demand for more gas have encouraged a resur-

see GAS CHALLENGE page 19

continued from page 18

GAS CHALLENGE

gence of gas exploration in the Cook Inlet basin. And, having already added to its supply portfolio the gas coming from Anchor Point Energy's new gas field at North Fork in the Kenai Peninsula, in early 2012 Enstar started taking delivery of gas from Buccaneer Energy's new Kenai Loop gas field in the city of Kenai.

In September Chugach Electric started accepting power from a new wind farm built on Fire Island, offshore Anchorage, by Cook Inlet Region Inc. The Fire Island power makes a small but welcome dent in the total utility demand for natural gas.

PRA supply projection

Consulting firm Petrotechnical Resources of Alaska, or PRA, has been keeping watch on the gas supply situation on behalf of the utilities. PRA uses analyses of actual field and well production decline rates, coupled with anticipated likely production and production decline rates for new gas wells, to project future gas supply rates and volumes.

In March 2012 the firm came out with a new supply projection, indicating that the utility gas supplies are likely to run short of demand around 2014-15. PRA said that the essential problem is that, despite the resurgence of interest in Cook Inlet gas exploration and development, gas drilling is not happening fast enough to sufficiently stem the gas supply decline. And although there are several gas exploration programs under way, new gas cannot be brought on line quickly enough and in sufficient quantity to head off the shortfall.

In addition, although there is a future possibility of shipping North Slope gas to Southcentral Alaska through some new pipeline, it will not be possible to design, permit and build such a pipeline before the gas shortage hits.

Enstar's contracts tight

An examination of the utilities' gas supply contract situation reveals a supply situation eerily close to PRA's projections.

Enstar finds itself in a particularly tight position. Since early 2011 the gas utility has been operating a bidding system, soliciting bids from gas producers on a day-by-day basis, to fill a growing gap between gas that the utility has under guaranteed contract and gas that it needs to fully meet winter gas demand. At the end of 2012 a Marathon gas supply contract came to an end, while the volumes of gas guaranteed under a Hilcorp Alaska supply contract stepped down at the same time that the Marathon contract ended.

Enstar has said that there will be enough gas available from the Cook Inlet basin to meet the utility's needs through the 2012-13 winter. But, under the gas bidding system, there is unwelcome uncertainty regarding both the source and the cost of that gas.

Chugach's needs dropping

Chugach Electric anticipates its gas needs dropping in the next three years. Chugach Electric and Municipal Light & Power are bringing a new, high-efficiency power station on line in early 2013, thus reducing the amount of gas that needs to be burned for power generation. There will be further drops in demand in 2014 and 2015 when the utility stops supplying power to Southcentral utilities Homer Electric Association and Matanuska Electric Association.

Despite this drop in Chugach Electric's gas needs, the utility has said that it is short of gas under contract in 2015, with that gas supply shortfall growing thereafter.

Homer Electric is building a new gas-fired power plant at Nikiski on the Kenai Peninsula, to generate power that from 2014 onwards will replace the power that the utility currently obtains from Chugach Electric. Homer Electric has said that it has gas supplies under contract through to March 2016, and that it optimistic about its needs being met through 2018.

Matanuska Electric finds itself in a particularly tricky situation. This utility is building a new gas-fired power plant at Eklutna, north of Anchorage, to generate power from 2015 onwards, after its power supplies from Chugach Electric come to an end. But Matanuska Electric does not yet have any firm gas supplies for the Eklutna power plant.

And all of the Southcentral power utilities are aware of a further potential problem. If Enstar were to run short of gas, thus causing the gas pressure in its transmission and distribution lines to fall below acceptable levels, the entire gas distribution system would likely have to shut down for an extended period, while gas engineers deal with the intricacies of shutting and later re-opening each individual gas meter. Rather than face a nightmare scenario of this type, especially in the winter, power utilities would redirect some of their gas supplies to Enstar to maintain the gas pressure. Thus, regardless of what supply contracts the power utilities have, a gas shortage for Enstar would cascade to a power generation gas shortage and consequent power cuts.

Importation coming

Faced with what appears to be an inevitable gas shortage in 2014-15 the utilities are taking steps to import gas from outside Alaska, either in the form of liquefied natural gas or compressed natural gas. Liquefied natural gas would presumably come from somewhere on the Pacific Rim, while compressed natural gas would likely come by sea from western Canada.

During the fall the utilities viewed presentation from five potential shippers of imported gas. The utilities subsequently commissioned consultancy firm Northern Economics to assess the relative merits of liquefied verses compressed gas

see GAS CHALLENGE page 21

Cook Inlet LNG exports continued in 2012

An announcement by ConocoPhillips in February 2011 that the company was going to close the liquefied natural gas export facility at Nikiski on Alaska's Kenai Peninsula came as no surprise, given the tightening gas supply situation in the Cook Inlet basin. But the Fukushima nuclear disaster about a month after the closure announcement dramatically changed the outlook for the Nikiski plant, as Japanese power plants upped their gas usage, causing an increased demand for liquefied natural gas, or LNG. And so LNG exports continued from Nikiski into 2012, albeit at a much lower rate that in the plant's heyday.

The Department of Energy's LNG export license for the plant allows exports to continue until March 2013 up to a specified volume of the product.

But how is it possible to export LNG from the Cook Inlet basin at a time when local gas and power utilities are facing a gas supply shortage? The utilities expect to run short of gas in about a couple of years' time, unless new sources of supply can be established.

Exports began in 1969

The LNG plant went into operation in 1969 to provide a market for huge volumes of excess gas from Cook Inlet oil and gas fields at that time. But with gas supplies becoming tight, the export of LNG has started to compete with the demand for gas from the utilities — in 2012 Cook Inlet Natural Gas Storage Alaska, or CINGSA, the company operating a new gas storage facility on the Kenai Peninsula, reported that it was experiencing difficulty obtaining all of the gas that it needed to build the necessary gas pressure in its storage reservoir, with CINGSA saying that some of the gas that it had anticipated obtaining for storage was instead being exported as LNG. CINGSA has subsequently continued purchasing additional gas into the winter, to ensure that its gas pressure requirements can be met.

LNG plant has helped utilities

Overall, the LNG plant has a history of helping rather than hindering the local utility gas industry. The utility market in Southcentral Alaska is small — the LNG

see LNG EXPORTS page 21

EXPLORATION & PRODUCTION

CGGVeritas permitting seismic program

CGGVeritas is permitting a 3-D seismic exploration program for this winter on Alaska's North Slope.

In a mid-December talk to the Alaska Geological Society Ed Duncan, president of Great Bear Petroleum, said Great Bear had contracted with CGGVeritas for 380 square miles of 3-D seismic, over what he described as "the central core of the ... Great Bear lease holding."

CGGVeritas said in an application to the Alaska Department of Natural Resources' Division of Oil and Gas that the survey will be on state lands beginning some 25 miles south of Prudhoe Bay along the western corridor of the Dalton Highway and proceeding westward.

CGGVeritas said it would acquire the seismic from Jan. 1 through May 31 and said it would be mobilizing its equipment and camp from its CGGVeritas Deadhorse location via the Dalton Highway.

The company said access and travel toward the program area would be determined based on weather, snow cover, ice depths and logistical considerations.

Twelve to 14 tracked vibrators will be used for seismic operations, supported by tracked cable trucks. The camp will house 160-180 in sled-mounted units including a kitchen and diner, sleeping areas, washrooms, offices, shops, generator rooms and storage compartments. CGGVeritas said that depending on the progress of the survey, the camp would move one to two miles every few days. During the active work season crews will travel to the camp by personnel carrier, bus or plane.

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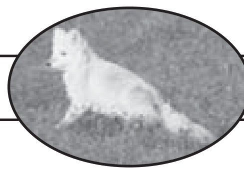

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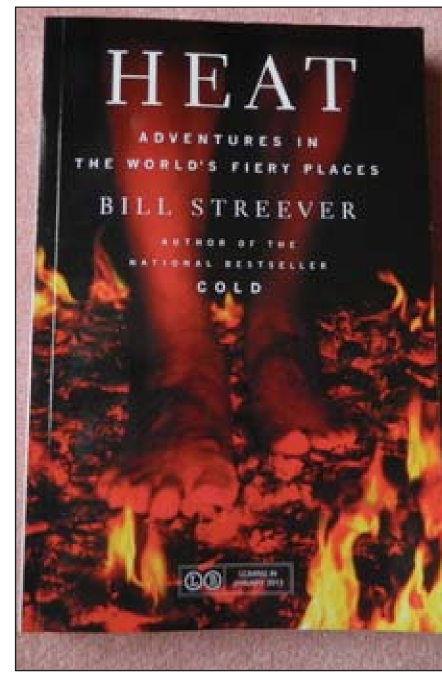
● BOOK REVIEW

Alaska author crafts adventure in 'Heat'

Biologist Bill Streever says insatiable curiosity fuels his drive to create bestselling nonfiction works about natural phenomena

By ROSE RAGSDALE

For Petroleum News



ROSE RAGSDALE

Bill Streever, Ph.D., is at the top of his game. The acclaimed author of "Cold" has done it again, trotting out another literary adventure for the average Joe that's sure to grab the attention of both critics and fans.

But precious little is average about "Heat: Adventures in the World's Fiery Places" (Little, Brown and Co.: $26.99/$29.99 in Canada; Hardcover; January 2013). A tidy 332-page read, "Heat" goes down as smoothly as a hot toddy on a winter night. In the words of Streever's publicist, the book "takes us on an adventurous ride through the most blisteringly hot regions of science, history and culture."

From its first few pages, "Heat," snags the reader's interest with compelling anecdotes that enliven the simplest and most well-worn concepts about warmth and refuses to let go.

From the floor of Death Valley to the heights of Hawaii's Kilauea volcano, Streever examines hot places and hot circumstances with an unbridled enthusiasm that resonates throughout his writing — a modern-day Indiana Jones seeking lost treasures of scientific understanding.

He takes us back billions of years to the hottest occurrence of all time: the big bang, and hurtles us forward to the era of the Atom bomb and quark soup, dishing up surprising tidbits about heat along the way. Did you know, for example, that you can safely dip your hand in certain melted metals (DON'T TRY THIS AT HOME!) and yet, should your entire body, heat up by just 10 degrees Fahrenheit, you will die?

From the obvious to the startlingly unexpected, "Heat" covers everyday topics such as matches, wildfires and firefighting, fever and the chemistry of cooking. The book also ventures into the realms of the rarely discussed, such as the history of peat, coal and oil and gas and what happens above 4 trillion degrees Fahrenheit.

The volume is also chockfull of amusing and self-deprecating passages as Streever chronicles his journey of discovery as the author attempts to start a fire with sticks, climbs into firefighting survival gear, examines a hundreds-year-old corpse and yes, best of all, walks on a bed of live coals and flaming wood heated to 1,000 degrees Fahrenheit.

I began to read early passages of "Heat" aloud to a companion as we traveled along a limited access highway. The two of us became so engrossed in the material that we forgot where we were going, missed our turn and had to backtrack nearly 20 miles to reach our destination.

Amid much laughter and some chagrin, I realized that in this book, Streever has crafted a rare delight: A treatise both enlightening and entertaining on a subject that we typically think we already know a great deal about.

Due out Jan. 15, "Heat" is already getting attention in the world of science writing. David R. Montgomery, author of "The Rocks Don't Lie: A Geologist Investigates Noah's Flood," described "Heat" as "an illuminating romp sure to delight connoisseurs of extreme geography and ignite everyone's inner pyromaniac."

And Publisher's Weekly has tapped it as a "Top 10 Pick, Science."

A curious mind

Streever, 51, a biologist who works

see 'HEAT' page 21

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continued from page 20

'HEAT'

for BP Exploration (Alaska) Inc. by day and writes books by night, said he set out to do with "Heat" what he had done with its predecessor, "Cold" — provide readers with a new vision of an everyday experience — how heat works, its history and its relationship to daily life.

In a Jan. 7 interview, Streever told Petroleum News that his activities in Alaska, including trips to the North Slope, inspired his previous book, "Cold."

But when he first proposed a book about heat, the editor asked him how he could have credibility on the subject, living in Alaska.

"I told him that in Alaska we know everything about heat because we spend so much time trying to stay warm," Streever said.

Is "Heat" a book about climate change? Streever says, "No."

"When I wrote 'Cold,' I had little snippets about climate change," he said. "And when I wrote 'Heat,' I didn't want it to be about climate change, but I included (the subject) as a thread through the book. I think that's more interesting. The books I've read about climate change seem to be preachy. They hit you over the head with 'doom and gloom.' I think we will see less and less of this … genre, thankfully."

Once he began researching "Heat", Streever found it to be an even bigger topic than he envisioned and ended up leaving out "a mountain of information" uncovered in his research.

"Did you know that cold bottoms out at about minus 460 degrees, which is absolute zero, while heat goes into the trillions of degrees?" Streever asks. "And did you know that the vast majority of time in the earth's history, the atmosphere couldn't support a flame?"

The questions raise specters of the book. Streever has a way of bombarding the reader with an avalanche of facts woven into an engaging narrative.

This writing style, he said, reflects his approach to life. One scientist colleague called Streever's books, "travelogues of discovery."

"I think it's the way I approach things. Every day all these questions are firing off in my mind," observes Streever. "I remember as a child being very curious. I think something beats that out of most of us as we get older, but in my case, it wasn't."

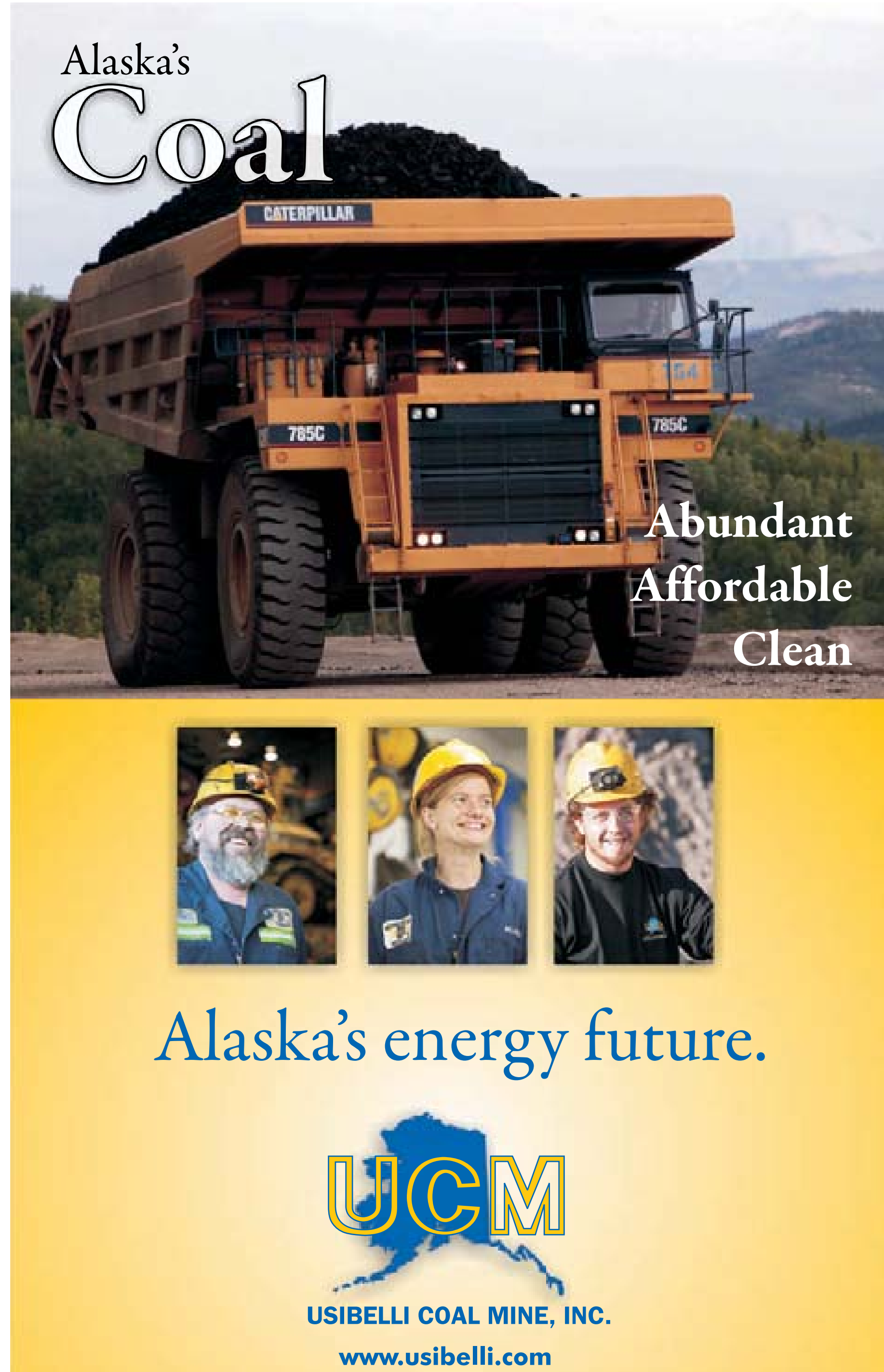
Streever's friends tell him that he is a great generalist, and that their natural curiosity about everything has been stifled by the need to focus on their specific areas of expertise.

He says John McPhee may be a kindred spirit. Highly regarded for the quality, quantity and diversity of his writing, the Princeton University journalism professor has written more than 26 books reflecting his eclectic interests. These include his widely read "Coming into the Country," about the Alaska wilderness, as well as works on the U.S. Merchant Marine, farmers' markets, freight transportation, the Mississippi River, oranges, basketball and a church.

Streever says he admires the kind of curiosity that could spawn such a legacy.

"I think the world would be a much better place if we were all constantly asking, 'what, why' and 'how.' "

Where will Streever's curiosity take him next? "I'm working on a new book now," he confided, "And "Gold" is the working title. ●



continued from page 19

LNG EXPORTS

plant has created a larger market, sufficient to justify the development and operation of large gas fields. And, by continuing its operations year round, the plant has enabled gas wells to continue production through the summer when utility gas demand is low: The temporary shutting in of a well in the summer will typically damage subsequent well performance by allowing water encroachment from the underground gas reservoir.

And, the LNG plant has provided a gas deliverability backstop for the utilities during severe winter cold — the plant has been able to provide that backstop by temporarily curtailing its own operations and diverting gas to the utilities.

But, with question marks over the LNG plant's future, the CINGSA storage facility which went into operation in 2012 is now providing the deliverability backstop. And, as Cook Inlet gas supply levels drop towards levels of utility demand, and as the end date of the LNG export license looms ahead, the LNG plant will presumably have to be shut in, at least until some new major gas fields come on line, something unlikely to happen for at least another few years.

—ALAN BAILEY

Contact Alan Bailey at abailey@petroleumnews.com

continued from page 19

GAS CHALLENGE

as import options, with the utilities anticipating a decision on an import arrangement by the end of the first quarter of 2013.

Meantime, some bells have begun to sound, apparently warning of the tight gas supply situation.

In November XTO Energy, operator of the Middle Ground Shoal oil field in the middle of the Cook Inlet, had to suspend oil production because of a shortage of gas to fuel the field platforms. And in December Cook Inlet Energy said that it was planning to revive a gas well in its offshore Redoubt Shoal field because of difficulties in purchasing fuel gas.

Also in December, following a cold start to the winter, Enstar had to come to an agreement with Hilcorp on how to pace the delivery of Hilcorp gas until the end of the year, to avoid hitting the contracted upper limit of Hilcorp's contracted 2012 supplies for Enstar. Had that upper limit been reached, Enstar would have had to draw unanticipated gas from CINGSA, thus depleting Enstar's stock of stored gas. Hilcorp did not want to deliver additional gas in 2012, for fear of compromising its ability to meet its contractual commitments in 2013.

And so, as the Cook Inlet gas industry moves into 2013, and as gas production from legacy fields continues to decline, interest will focus on just how much more gas can be squeezed from those old fields; the speed at which new fields can be brought on line; the size of those new fields; and progress in finding some way of bringing much needed additional gas into Southcentral Alaska from elsewhere. ●

Contact Alan Bailey at abailey@petroleumnews.com

● EXPLORATION & PRODUCTION

Cook Inlet investment surges in 2012

After years of declining investment, several independents small and large are taking a shine to the scrappy but prolific basin

By ERIC LIDJI
For Petroleum News

Cook Inlet undoubtedly went through a renaissance in 2012.

While dwindling supplies remain a concern, the year saw companies large and small making significant investments in the basin after years without exploration and only limited development. If the most ambitious companies were successful, the region would see increased oil and natural gas volumes some 55 years after production began.

The 2012 highlights include: newcomer Hilcorp poised to become the dominant player in Cook Inlet after acquiring the assets of Union Oil Company of California and Marathon; two jack-up rigs after years without any in the region; Apache continuing to permit a major seismic campaign across the entire basin; and independents such as Armstrong, Buccaneer, Cook Inlet Energy, Furie and NordAq drilling wells and shooting seismic.

The details, presented in alphabetical order by company, are as follows:

Apache drills

Although it arrived in the state in mid-2010, Apache Corp. made itself at home in Alaska in 2012, both literally and figuratively. Literally, the large Houston-based independent opened a new Alaska office in Anchorage in March 2012, at 510 L Street, Suite 310.

Figuratively, Apache undertook its most significant exploration work in the state to date: acquiring additional acreage, continuing its seismic program and spudding its first well.

In May, Apache picked up seven state leases at the annual areawide lease sale, filling in gaps in its existing leasehold. The acquisition included one large offshore tract in a block of leases from Anchor Point to Kenai, and six tracts near its leases northeast of Nikiski.

In August, Apache and the Alaska Native corporation Cook Inlet Region Inc. announced an agreement allowing Apache to explore for oil and gas on any CIRI land in the Cook Inlet basin not currently under lease — a significant addition to the roughly 589,000 acres Apache already leases from the state, as well as its previous leases across Native lands.

The wide access could serve Apache well should it discover any intriguing oil and gas prospects with the wide reaching 3-D seismic program it is shooting across the basin.

Apache is using state-of-the-art, nodal seismic technology for the program, which includes onshore, nearshore and offshore targets on both sides of Cook Inlet. Following a test of this equipment in early 2011, Apache proposed a three-year seismic survey, but complications in the federal permitting process delayed those plans in mid-2012.

In a March opinion, the National Marine Fisheries Service concluded that the program "is not likely to jeopardize the continued existence of the Cook Inlet beluga whale or Steller sea lion populations, nor to destroy or adversely modify Cook Inlet beluga whale critical habitat." In September, after finishing surveys on the west side and some of the northern end of the Inlet, Apache paused the program while it waited for additional permits from the NMFS, the U.S. Army Corps of Engineers and the U.S. Fish and Wildlife Service.

Those delays haven't kept Apache from drilling, though.

After initially outlining plans to drill one well on each side of the basin in 2012, Apache focused its efforts on a plot on the west side where it had completed its seismic work.

In mid-November, Apache started drilling the Kaldachabuna No. 2 exploration well on Cook Inlet Region Inc. subsurface land near Tyonek using the Patterson Rig 191.

The well is following up on a discovery Simasko Production Co. made with the Kaldachabuna No. 1 well in mid to late 1980. While the well initially caused waves in the investing world, subsequent tests found no "commercial accumulation of hydrocarbons."

Generally speaking, Apache believes there is as much oil still to be discovered in the Cook Inlet basin as has already been produced in the 55-year history of the basin.

Armstrong expands North Fork

After years as a pioneering exploration company, Armstrong settled in as a Cook Inlet producer in 2012 by expanding its significant development: the onshore North Fork unit.

The expansion took three forms: enlarging the southern Kenai Peninsula unit, drilling additional natural gas development wells and helping to open new markets in the region.

In July, the Alaska Department of Natural Resources agreed to expand the unit, adding some 2,903 acres in a ring around the western edge of the formerly 640-acre unit. The state also expanded the North Fork gas pool participating area to 800 acres total.

From mid-September through the end of the year, Armstrong and its partners at the field used the Nabors 99 rig to drill two new wells designed to increase gas production at North Fork, the NFU No. 23-25 well and the NFU No. 22-35. The two-well program goes beyond Armstrong's current work commitments. Armstrong also permitted two other wells — NFU No. 33-35 and NFU No. 42-35 — that it could drill in the future.

Under the 47th plan of development for North Fork — in place until March 2013 — Armstrong must test additional zones in the NFU No. 34-26 well and drill at least one additional well at the field to target a previously untested segment of the Tyonek.

Those efforts are helped by a recent 3-D seismic acquisition that "greatly improved the regional structural definition of the four-way anticlinal North Fork clo-

see CI INVESTMENT page 23

continued from page 22

CI INVESTMENT

sure," according to state filings. The trick at North Fork is to find productive patches within the sandstones, Vice President of Land and Business Development Ed Kerr told Petroleum News in September. "Depositionally, these are lenticular sands, so they come and go," Kerr said, referring to layers of sands and mud. "We're drilling through a package of sands."

Through its pipeline subsidiary Anchor Point Energy LLC, Armstrong is also working with Enstar Natural Gas Co. to expand natural gas distribution in the southern Kenai.

In early 2012, the state approved a grant to help build a transmission line to the cities of Homer and Kachemak City. And in August, the state gave Anchor Point Energy and Enstar approval to build a short, state-funded pipeline into the community of Nikolaevsk.

Aurora stumbles at Cohoe

In addition to its regular development and production activities, Aurora Gas LLC saw its attempts to form a unit on the Kenai Peninsula come to an apparent end in 2012.

In July 2010, Aurora applied to form the Cohoe unit over the two state leases and an adjoining lease owned by Cook Inlet Region Inc. A two-year plan of exploration proposed re-entering the Cohoe Unit No. 1 well from 1973 and gathering new 3-D seismic data. After a more than a year of discussions, the Alaska Department of Natural Resources rejected the unit in September 2011, saying the work could be undertaken without unitization. Aurora appealed, but the state upheld the ruling in May 2012.

In an unusual move, the independent investor Dan Donkel appealed the ruling, saying his overriding royalty interest in the Cohoe leases entitled him to challenge the ruling.

Buccaneer starts production …

Buccaneer Energy Ltd. became a producer in 2012, but the company delayed much of its ambitious exploration plans for Cook Inlet as it worked to bring a jack-up rig to Alaska.

After drilling two wells in 2011, Buccaneer brought the onshore Kenai Loop field into production in January 2012. By the end of the year, Buccaneer said it had increased production from the field to 6.5 million cubic feet per day, up from 5 million cubic feet per day.

In April, Buccaneer began selling 5 million cubic feet per day into the Cook Inlet Natural Gas Storage Alaska facility. As production increased in October and December, Buccaneer announced two small-volume, short-term sales agreements with unnamed third parties.

Looking to expand its onshore work, a Buccaneer subsidiary signed a three-year lease in June on the Marathon Glacier 1 purpose-built truck-mounted drilling rig. In September, it used the rig to drill the Kenai Loop No. 4 well. A "small leak in the well liner" delayed testing toward the end of the year, but Buccaneer said the leak has been plugged and the well "identified multiple sands with indications of gas within the Tyonek formation."

And after processing a 3-D seismic acquisition over the region, Buccaneer said it now believes the producing formation at Kenai Loop is much larger than it originally thought.

In December, Buccaneer applied to form the 7,500-acre Kenai Loop unit, including four State of Alaska leases, two Alaska Mental Health Trust leases and one Cook Inlet Region Inc. lease. In proposed plan of development for the unit, Buccaneer said it would include between one and three wells per year at Kenai Loop for the first five years of the unit.

In October, Buccaneer also applied to form the 46,395-acre West Eagle unit over a block of onshore leases in the southern Kenai Peninsula set to expire. In its unit application, the company said it was "poised to drill" at West Eagle, but needed assurances it would be able to keep its acreage. Buccaneer also proposed a 61 square mile 3-D seismic survey.

… but exploration is delayed

Originally, Buccaneer planned to use its Endeavour jack-up rig to drill wells at its offshore Southern Cross and Northwest Cook Inlet units by September 2012, but as the summer months passed without the rig embarking from a shipyard east Asia to the Cook Inlet, the company was forced to defer its plans by one year. The state put the two units in default in October, giving Buccaneer until October 2013 to drill its initial wells at both.

With the extra time, Buccaneer planned to drill at Cosmopolitan, a field off the coast of the southern Kenai Peninsula. Alongside the Fort Worth-based BlueCrest Energy II, LP, Buccaneer purchased the two-lease prospect in February and closed the deal in August.

Although the Endeavour rig arrived in Cook Inlet in September, at the end of the year it was docked in Homer as crews completed maintenance and upgrades started overseas.

The nature and history of those upgrades is the subject of a lawsuit between Buccaneer and Archer Drilling LLC, its original operator on the rig. After the companies parted ways in mid-December — with each claiming to have terminated the agreement with the other — Buccaneer hired Spartan Drilling LLC to take over as the operator of the rig.

Having recently received a land use permit from the state, Buccaneer hopes to soon move the rig to Cosmopolitan and get the final permits to begin its proposed two-well program.

Conoco keeps on keeping on

After four years of major investments to its legacy assets in Cook Inlet, ConocoPhillips saw its activities in the basin decline considerably in 2012, but not peter out completely.

ConocoPhillips drilled at least two new Cook Inlet wells in 2012 — Beluga River Unit 242-04 between April and July and Beluga River Unit 244-23 between June and September — according to Alaska Oil and Gas Conservation Commission information.

And after announcing plans in 2011 to shut down its pioneering Kenai Peninsula liquefied natural gas export terminal, ConocoPhillips unexpectedly kept the facility open the entire year as demand from Asia justified additional shipments. Although the current export license expires on March 31, 2013, ConocoPhillips said it believes the plant "has options for the future" depending on the course of regional natural gas production.

Another longtime producer, XTO Energy, initiated no major development activities in 2012, but highlighted a major concern about the state of the basin when it suspended oil production at its two Middle Ground Shoal platforms because of a shortage of fuel gas.

Cook Inlet Energy gearing up

As it focused on recompleting wells from the Osprey platform, Cook Inlet Energy LLC also found time in 2012 to drill an exploration well and plan for future exploration work.

After relinquishing five leases in February around its proposed Stingray exploration program on the west side of Cook Inlet, the company used its rig 34 to drill the Otter No. 1 exploration well to some 5,600 feet in the area 10 miles north of the Beluga gas field.

"The mud loggers reported two significant hydrocarbon gas shows in the zone of interest," CEO David Hall said in July. "We're very excited about the Otter No. 1."

The Otter No. 1 well tested the Beluga formation, but mud pump problems kept the company from drilling to its intended depth of 7,000 feet. Cook Inlet Energy is now planning to drill a second Otter well to 7,500 feet to test the Tyonek formation, and an exploration well at Olsen Creek, a shallow gas prospect southwest of the Otter prospect.

In December, Cook Inlet Energy asked the Alaska Mental Health Land Trust to expand a soon-to-expire lease on "highly prospective" land 10 miles north of Tyonek, in the vicinity of Otter and Olsen Creek, in return for drilling two wells by the end of 2013.

Cook Inlet Energy also expanded its holdings in 2012.

In April, the company picked up the 45,764-acre Susitna Basin V exploration license, its third, smallest and — at five years — shortest exploration license in the area north of Anchorage. The company is now licensing some 580,147 state acres for exploration.

At a lease sale in May, Cook Inlet Energy bid $2.7 million on 74,880 acres, including leases north of Clam Gulch, north of its West McArthur River unit and north of the Trading Bay unit. The company "got everything we went after," Hall said after the sale.

In September, Cook Inlet Energy acquired the outstanding minority interest in its two leases covering the Sword and Sabre prospects on the west side of Cook Inlet.

And during the year, Cook Inlet Energy also proposed the $50 million Trans-Foreland Pipeline, a 29-mile subsea pipeline across Cook Inlet to improve oil shipments.

Furie returns to KL unit

After announcing a headline inducing natural gas discovery at the offshore Kitchen Lights unit in late 2011, Furie Operating Alaska LLC took a quieter approach in 2012.

The Houston-based company completed two wells and one sidetrack, and began permitting a development plan for the massive unit in the waters of the upper Cook Inlet, while also fighting a federal fine over its tactics for bringing a jack-up rig to Alaska.

After suspending operations on the Kitchen Lights Unit No. 1 well in October 2011 at 8,805 feet, halfway to target depth, Furie re-entered the well in May 2012, again using the Spartan 151 jack-up rig to finish the job. The company reached a total depth of 15,298 feet in August, above the pre-Tertiary zone, and moved the rig to drill to another location.

Furie began drilling the Kitchen Lights Unit No. 2, but as of late October the well had not reached a depth below 9,000 feet, according to information obtained by Petroleum News.

By late October, though, Furie had completed a sidetrack to Kitchen Lights Unit No. 2.

As it continues exploring the prospect, Furie is permitting the KLU Platform A to underpin long-term gas production in the region. According to filings with the U.S.

see **CI INVESTMENT** *page 24*

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continued from page 23

CI INVESTMENT

Army Corps of Engineers, Furie described a platform with a 64.5-foot by 72-foot deck, an 18-foot diameter caisson, two subsea gathering lines and a new production facility.

In early 2012, the Alaska Department of Natural Resources gave Furie a four-year extension of the Kitchen Lights unit terms, through January 2016. The plan attached to the extension called for finished KLU No. 1 and drilling at least four new wells.

But early in the year, the U.S. Customs and Border Protection upheld a $15 million fine against the company formerly known as Escopeta Oil Co. for moving the Spartan 151 jack-up from Texas to Cook Inlet using a foreign-flagged vessel, without having a valid waiver of the federal Jones Act. Furie sued the U.S. Department of Homeland Security over the fine, which it claims is unwarranted and said is scaring away potential investors.

Hilcorp arrives

In 2012, Hilcorp became a major player in the Cook Inlet.

In January, Hilcorp closed on its 2011 acquisition of the Cook Inlet assets of Union Oil Company of California, becoming the operator of the Deep Creek, Ivan River, Lewis River, Nikolaevsk, Pretty Creek, South Granite Point, South Middle Ground Shoal, Stump Lake and Trading Bay units, and picking up interests in numerous other oil and natural gas fields, offshore platforms, pipelines and storage facilities across the basin.

In April, Hilcorp acquired the Cook Inlet assets of Marathon Oil Corp., which, once the deal closes, would make it operator of the Beaver Creek, Cannery Loop, Kasilof, Kenai, Ninilchik, North Trading Bay and Sterling units, plus pipelines and a storage facility.

Hilcorp said it spent around $230 million in Alaska in 2012, with about half going to new developments and around 38 percent going toward refurbishing old assets in its portfolio.

Those efforts included working on existing wells at legacy fields, but several larger developments as well. For much of the year, Hilcorp worked to re-activate the Drift River oil terminal closed by the 2009 eruption of the Redoubt volcano and thereby resume normal operations for the shipping of oil from the west side to the east side of the inlet.

In December, Hilcorp began producing some 5 million cubic feet per day from the Red Pad in the Nikolaevsk unit and helped fund a southern Kenai pipeline to market the gas.

During the year, Hilcorp also drilled three wells at the Deep Creek unit to maintain natural gas production, and applied for a permit to shoot 3-D seismic in the region.

In May, Hilcorp filled-in its newly acquired assets across the basin by bidding $3.1 million on 82,560 acres — 18 tracts — in the annual Cook Inlet areawide lease sale.

Linc gets unconventional

Linc Energy Inc. saw its conventional gas ambitions in Cook Inlet stall in 2012, but it pushed ahead on plans the produce gas from underground coal deposits within five years.

The Australian independent started the year with some 123,000 acres spread across the basin, but the majority of its state acreage expired in June, leaving the company with just one state lease, as well as its Alaska Mental Health Trust leases and exploration licenses.

In June, Linc applied to form the Angel unit over its remaining state lease and a contiguous Alaska Mental Health Trust lease covering some 1,700 acres in the Point Mackenzie region where Linc drilled the LEA No. 1 exploration well in late 2010.

Saying its well data had found a geologic feature worthy of further investigation, Linc proposed a two-year program of drilling and seismic acquisition, but the state ultimately denied the unit application. "At this time, Linc Energy has not presented a structural trap that is reasonably defined and delineated, and therefore has not identified a potential hydrocarbon accumulation for the proposed Angel unit," the state wrote in its decision.

Linc said it planned to either appeal the decision, or resubmit its application.

Meanwhile, the company began exploring potential underground coal gasification prospects on the lands its holds under an Alaska Mental Health Trust exploration license.

In early 2012, Linc finished drilling the TYEX01 and TYEX01X core holes on the west side of Cook Inlet, near the Beluga Power Plant, and called the results "very encouraging." In mid-2012, Linc received the Linc Energy Core Rig No. 1, a rotary-core rig custom built by Buffalo Custom Manufacturing, but bad weather postponed its plans to use the rig to drill the KEEX02 core hole 18 miles southwest of the Beluga airstrip.

In May, the Alaska Oil and Gas Conservation Commission gave Linc a permit to drill the LDRT No. 1 core hole in the vicinity of its LEA No. 1 well. In late November, the AOGCC gave Linc a permit to drill the TYEX02 core hole near TYEX01 and TYEX01X.

NordAq preps two prospects

NordAq Energy Inc. made progress on two Cook Inlet prospects in 2012. Although only some 20 miles apart, the two prospects are on opposite sides of the basin.

On the east side, NordAq moved ahead on plans to develop its Shadura prospect. The company claims to have made a large discovery in early 2011 with the Shadura No. 1 well, drilled on Cook Inlet Region Inc. land in the Kenai National Wildlife Refuge.

The plan calls for drilling up to six production wells at a site about 13 miles northeast of Nikiski, in the northwest portion of the refuge west of Hilcorp's Swanson River unit.

In a recent draft environmental impact statement, NordAq proposed a two-stage construction process. First, it would build limited infrastructure to support an initial test well. Then, if the well results were favorable, it would expand the infrastructure to support five more development wells, an industrial water well and a waste disposal well.

In support of the development, NordAq is permitting a 49-square-mile 3-D seismic survey over the Shadura, scheduled to take place over the first four months of the year.

NordAq anticipates bringing the field into production as soon as 2014.

The U.S. Fish and Wildlife Service is currently taking comments on the draft EIS.

On the west side, NordAq began exploring its Tiger Eye prospect.

In October, the state approved formation of the 7,680-acre Tiger Eye unit covering two onshore leases near the mouth of the Kustatan River, within the Redoubt Bay Critical Habitat Area.

The Tiger Eye unit agreement called for NordAq to drill a well by the end of 2012, another by the end of 2013 and to conduct a 3-D seismic survey over the region in 2013.

Shortly after getting the unit, NordAq used Nabors Alaska Drilling Rig 106AC to drill the Tiger Eye Central No. 1 well, targeting the Tyonek and Hemlock formations.

The company plans to drill the Tiger Eye North well next year. ●

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● NATURAL GAS

In-state gas pipeline bill already filed

Proposal stalled in Senate last year, but House leadership prepared to try again, this time proposing AGDC as standalone agency

By KRISTEN NELSON

Petroleum News

MIKE HAWKER

MIKE CHENAULT

Once crude oil began moving off Alaska's North Slope in the mid-1970s, natural gas was supposed to follow. But Lower 48 natural gas prices crashed, dooming the 1980s project.

There have been proposals since, but none has been able to surmount the economic hurdle of moving gas off the North Slope — itself a challenge — and then to market either via a pipeline through Canada to the Lower 48 or by liquefying the gas and moving it to Asian markets as liquefied natural gas, LNG.

Most recently the state backed a line to the Lower 48 under AGIA, the Alaska Gas Inducement Act, enacted in 2007 under former Gov. Sarah Palin, but that project foundered when the Lower 48 was flooded with natural gas from shale developments.

In the fall of 2011, Gov. Sean Parnell called for greater alignment among potential shippers of North Slope natural gas — and said that alignment should be for a line going to tidewater, with natural gas going to the Pacific Rim as LNG.

Parnell said at the time that TransCanada and ExxonMobil, partners in the project licensed under AGIA, hadn't been able to move forward with negotiations with potential shippers for natural gas to the Lower 48, and said the problem might be that the market for natural gas has shifted since AGIA was passed, due to the glut of natural gas in the Lower 48, "the devastating tsunami in Japan and that nation's subsequent drift away from nuclear power, and other market forces in the Pacific Rim."

"It all means that a better market for Alaska gas could very well be in Pacific Rim countries," Parnell said, adding that AGIA does allow for reassessment of market conditions.

He cited what appeared to be an impasse on a line to the Lower 48, and said he had asked TransCanada, ExxonMobil, BP, ConocoPhillips and the Alaska Gasline Development Corp. to move forward on a large-diameter line to tidewater to take natural gas to the Pacific Rim as LNG.

BP, ConocoPhillips and ExxonMobil are the North Slope natural gas owners.

The in-state proposals

But it isn't just marketing North Slope natural gas in the Lower 48 or on the Pacific Rim: There are also efforts under

see **PIPELINE BILL** *page 26*

● EXPLORATION & PRODUCTION

Hebron gets corporate nod, ends feuding

By GARY PARK

For Petroleum News

Partners in the ExxonMobil-led Hebron oil project offshore Newfoundland have sanctioned the development, ending more than a decade of often nasty dealings between the government and the consortium.

The US$14 billion venture is now scheduled to deliver its first oil in 2017, with output ranging at 150,000 barrels per day to a possible 180,000 bpd from a field estimated to hold 700 million barrels of recoverable resources, 300 million barrels more than initially projected.

The proponents, as part of their regulatory application, have held out hopes that expansion is possible if additional studies, seismic surveys or exploration/delineation drilling identify more economically recoverable oil pools

Any excess associated natural gas will be stored in area reservoirs, or used to increase reservoir pressure.

The field is 200 miles southeast of St. John's, the Newfoundland capital, and 19 miles southeast of the ExxonMobil-operated Hibernia project, and lies in 300 feet of water.

Fourth offshore project

It will become Newfoundland's fourth commercial offshore project after Hibernia, Terra Nova and White Rose.

Like Hibernia, Hebron will use a standalone gravity-based structure, or GBS, to recover the oil, believing that design will "withstand sea ice, icebergs and meteorological and oceanographic" challenges posed by the North Atlantic, the company said in a statement.

The 400-foot high GBS will be capable of storing 1.2 million barrels.

From its outset, Hebron has led a fractious existence, culminating with a bitter showdown between ExxonMobil and then-Newfoundland premier Danny Williams.

The turbulent history has seen changes in the ownership structure with Chevron Canada relinquishing the operator's role and feuding with the Newfoundland government over royalties, which were overcome when the provincially owned Nalcor Energy Oil and Gas acquired a minority equity position.

Chevron twice shelved the project and disbanded the project team in arguing capital costs were too high to make the venture economically viable

October resolution

A final obstacle was resolved in October when Newfoundland Premier Kathy Dunderdale announced a deal that would see ExxonMobil pay the province C$150 million in compensation rather than build a key offshore drilling equipment module at Bull Arm, Newfoundland.

The two sides had disagreed over whether the Bull Arm facility had the capacity to handle the drilling equipment module without affecting the project schedule.

Dunderdale said the C$150 million payment was equal to the value of the third module.

ExxonMobil said "significant progress has been achieved on detailed engineering" for the project and construction of the GBS platform is under way.

An ExxonMobil Canadian subsidiary will operate Hebron through a 36 percent equity stake, with Chevron Canada holding 26.7 percent, Suncor Energy (which inherited its share by taking over Petro-Canada) 22.7 percent, Statoil Canada 9.7 percent and Nalcor 4.9 percent.

C$23B in royalties, taxes

Dunderdale said her government expects to collect C$23 billion in royalties and corporate income taxes over Hebron's 25-year operating life.

Bob Cadigan, president and CEO of the Newfoundland & Labrador Oil & Gas Industries Association, said in a statement that although his member companies are disappointed the third module will not be built at Bull Arm, Hebron remains a "good project. We want to see it continue to advance."

The construction phase will generate about 3,500 jobs in Newfoundland.

Observers have held out hopes that proceeding with Hebron will stimulate further investment in Newfoundland's deepwater Orphan basin and Flemish Pass, even though operating conditions vary.

Natural Resources Minister Jerome Kennedy said the development of Hebron will increase Newfoundland's offshore production, adding new major infrastructure to the Jeanne D'Arc Basin. ●

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continued from page 1

POINT THOMSON

tered higher levels of hydrogen sulfide than expected.

Hydrogen sulfide, or H_2S, is a sour or acidic gas that can be very damaging.

The PTU-15 and PTU-16 well materials were not designed for "sour service" and will need casing mitigation, ExxonMobil has told state oil and gas industry regulators.

Ultimately, both wells will be used as injectors, and a third well will be drilled as the initial Point Thomson producer, the company said.

Schedule remains intact

Kim Jordan, an ExxonMobil spokeswoman in Houston, told Petroleum News on Jan. 9 that the sour gas issue "does not impact the overall schedule" for the Point Thomson development.

Major field construction has not yet occurred at Point Thomson, but is expected to begin ramping up this winter.

Likewise, state Natural Resources Commissioner Dan Sullivan said work appears to be proceeding according to plan.

Under a legal settlement with the state, ExxonMobil has pledged to commence initial production at Point Thomson by the winter of 2015-16, or no later than May 1, 2016.

"In none of our briefings with Exxon has there been even the hint of that important date not being abided by," Sullivan said in a Jan. 9 interview.

ExxonMobil detailed the sour gas problem during a recent briefing of officials with the Alaska Oil and Gas

see **POINT THOMSON** *page 27*

Point Thomson timeline

Aug. 1, 1977 – Point Thomson unit formed.

Sept. 30, 2005 – Mark Myers, state oil and gas director, finds Point Thomson unit agreement in default due to operator ExxonMobil's failure to submit acceptable plan of development.

April 22, 2008 – Tom Irwin, state natural resources commissioner, terminates Point Thomson unit.

May 8, 2009 – With Irwin's permission, ExxonMobil spuds first of two wells at Point Thomson.

Jan. 11, 2010 – ExxonMobil and partners score major victory when Superior Court Judge Sharon Gleason of Anchorage reverses Irwin's unit termination.

Oct. 27, 2010 – ExxonMobil announces it has finished drilling wells.

March 29, 2012 – State, oil companies reach settlement resolving legal conflict, laying out schedule for Point Thomson development.

Oct. 26, 2012 – U.S. Army Corps of Engineers issues permit for field construction. Permit allows activity that disturbs wetlands, navigable waters.

Oct. 31, 2012 – DNR Commissioner Dan Sullivan signs right-of-way lease for 22-mile Point Thomson export pipeline.

Nov. 30, 2012 – Regulatory Commission of Alaska grants ExxonMobil certificate of public convenience and necessity for pipeline.

May 1, 2016 – ExxonMobil's deadline for field startup.

—WESLEY LOY

continued from page 25

PIPELINE BILL

way to get natural gas to Alaskans.

Recent work has been spurred out of the governor's office and the Legislature.

In 2008, then Gov. Palin tasked the Alaska Natural Gas Development Authority, ANGDA, with a gas pipeline from Southcentral to Fairbanks. This was in addition to work the authority was doing on a spur line to Southcentral from the proposed North Slope mainline.

In early 2009 Palin established an in-state gas pipeline project in the governor's office, naming Harry Noah as project manager, with a goal of supplying the Railbelt with natural gas within 5 years.

Noah told legislators in late December 2009 that there were too many in-state gas project plans in play

"We are pulling this way and we're pulling that way," and while good people are involved on the different project, Noah told a meeting of House Resources, "one side just wants to kill the other side."

And, he said, the Legislature is funding the competing projects.

Whether spurred solely by getting gas to Alaskans or by the dueling state projects, in 2010 legislators in both the House and Senate worked on legislation to consolidate an in-state gas pipeline under one agency.

That legislation, passed as House Bill 369, sponsored by House Speaker Mike Chenault, R-Nikiski, established the Alaska Gasline Development Corp.

HB 369 was merged with Senate legislation and signed into law by Parnell in late April, creating the Joint In-State Gasline Development Team and putting Alaska Housing Finance Corp. CEO and Executive Director Dan Fauske in charge of the team, which was established as an AHFC subsidiary.

The purpose of the team was to develop and deliver to the Legislature by July 1, 2011, a plan for an in-state natural gas pipeline which would be operational by the end of 2015.

The report delivered to the Legislature in July 2011 found the project economic, but said the 2015 completion date was not realistic given the time required for permitting, holding an open season and securing financing. The report envisaged a completion date near the end of 2018, with first gas in 2019.

Changing legislative requirements

As AGDC worked on the project, it identified a number of changes it needed in its statutory authority to proceed, and those were introduced — and some passed by the House — in the 2011 session.

In 2012 the House legislation was merged into House Bill 9, with Chenault and Rep. Mike Hawker, R-Anchorage, as chief sponsors. The bill passed in the House, but languished in the Senate.

Chenault described HB 9 as a bill that would keep momentum going for development of gas for Alaska, "while keeping open all the options for participating in an aligned project," referring Parnell's proposal that a large line under AGIA could morph into an LNG project and combine with an in-state gas project.

Hawker said the bill would bring state agencies, including ANGDA, "together into a common mission with a common management," eliminating the ANGDA board and moving ANGDA under the AHFC board; the AHFC board would also replace the Joint In-State Gasline Development Team, which was the board for AGDC under HB 369.

The bill also established a fund to receive $200 million appropriated in 2011 for work on an open season, limited challenges to right-of-way leasing decisions, allowed AGDC to enter into confidentiality agreements, gave AGDC the ability to determine pipeline ownership and operating structure, issue bonds and manage pipeline and related project assets.

The bill also allowed AGDC to operate a pipeline as a contract carrier and provided the option of Regulatory Commission of Alaska oversight.

ANGDA's role would focus on marketing under the bill, giving it the ability to pledge royalty gas owned by the state as long as that gas was not already committed by contract.

House Bill 4

House Bill 4, pre-filed for the 2013 Legislature, incorporates the provisions of HB 9 but would establish AGDC as a separate state agency, akin to the Alaska Railroad Corp. or AHFC.

It also addresses the contract carrier issue differently than HB 9, creating a new section of Regulatory Commission of Alaska statutes for in-state pipeline contract carriers, allowing contract carriage and giving RCA oversight.

This has been an issue for an in-state gas pipeline because current statutes for in-state lines allow only common carriage, which would require prorating space on a line to accommodate new shippers. Because an in-state gas pipeline is expected to have contracts with utilities, which require continual gas delivery at specified rates, those shipping on the line need the certainty of contract carriage.

As with HB 9, AGDC's need for confidentiality is addressed, allowing it to enter into confidentiality agreements — an authority it does not currently enjoy.

The big line project

The Alaska Pipeline Project, the TransCanada-ExxonMobil AGIA-licensed mainline project, held an open season in 2010. Multiple bids were received, followed by months of negotiations, but no precedent agreements — binding commitments to "ship or pay" on the line — were ever signed.

In early May 2012, TransCanada notified the Federal Energy Regulatory Commission that it was terminating that first binding open season.

TransCanada received the AGIA license for the project in late 2008 and ExxonMobil joined the Alaska Pipeline Project in mid-2009.

TransCanada told FERC that while "significant interest" was expressed in capacity on a line going to Alberta during the open season in the form of conditioned bids, no precedent agreements were every signed. TransCanada said it was APP's "assessment that the producers are not prepared to make commercial commitments to the Alberta Project at this time."

APP is working with the Alaska North Slope producers on the feasibility of a project for a pipeline to an LNG facility at tidewater in Southcentral Alaska and a new open season would be initiated if those evaluations led to a project that appears com-

see **PIPELINE BILL** *page 32*

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continued from page 26

POINT THOMSON

Conservation Commission and the Department of Natural Resources.

DNR provided a copy of ExxonMobil's PowerPoint presentation from the Oct. 30 briefing to Petroleum News. The sour gas issue previously was not known publicly.

Long struggle

The Point Thomson unit is on state-owned acreage along the Beaufort Sea coastline, about 60 miles east of Prudhoe Bay and just west of the Arctic National Wildlife Refuge.

The field is believed to contain hugely valuable reserves of natural gas, estimated at 8 trillion cubic feet. ExxonMobil says it also contains an estimated 200 million barrels of condensate, a light liquid hydrocarbon associated with natural gas.

Despite its riches, the field has yet to produce any gas or oil since its discovery in the 1970s. ExxonMobil and its partners in the field have cited the lack of a North Slope natural gas pipeline, as well as the field's remote location and technical challenges, as reasons for the lack of development.

Beginning in 2005, state officials began to take increasingly aggressive steps to try to force ExxonMobil to produce at Point Thomson. A court conflict soon developed as the oil companies sought to block the state's attempts to dissolve the unit and invalidate the underlying leases.

Under pressure, ExxonMobil drilled a pair of wells at Point Thomson. Finally, on March 29, 2012, the state and the oil companies reached a settlement agreement that resolved all the legal issues and laid out a schedule for the gradual development of the field.

While the settlement does not guarantee production, ExxonMobil and its partners will lose acreage if they don't move forward with development, state officials say.

The other major stakeholders in Point Thomson are BP and ConocoPhillips.

How project will work

The first development phase, known as the "initial production system," will be designed to produce 10,000 barrels per day of condensate to start.

Major field construction has not yet occurred at Point Thomson, but is expected to begin ramping up this winter. The project will involve establishing central, west and east pads; infield roads and gathering lines; worker housing and a barge dock; and a 22-mile export pipeline to tie Point Thomson production into the existing North Slope oil transportation network.

ExxonMobil has acquired the major authorizations, including a federal wetlands permit and a state certificate of public convenience and necessity for the pipeline.

The condensate production involves producer and injector wells "cycling" gas in tandem. The producer well brings wet gas to the surface. The gas goes into processing facilities for collection of the condensate. The injector well then shoots the residual dry gas back underground.

At the Oct. 30 briefing, ExxonMobil told state officials the potential consequences of the high H2S levels in the PTU-15 and PTU-16 wells. The company said testing determined that "under a shut-in condition with a well tubing failure, the well casing could experience rapid corrosion."

The wells are "suspended in a safe condition," and were inspected in July 2012, ExxonMobil said.

Going forward, the company plans to use both wells as injectors after installation of liners.

Jordan, the ExxonMobil spokeswoman, further explained in an email: "The liners, with reduced internal diameters, required the use of smaller production tubing which reduced the flow capability of both wells. For this reason, both the PTU-15 and PTU-16 will be used as injectors."

ExxonMobil has told state officials it intends to accelerate the planned drilling of another well at the west pad. This well will be the producer, able to provide "the required flow rate to achieve the design rate level agreed in the Settlement Agreement," Jordan's email said.

The agreement calls for cycling 200 million cubic feet per day of gas.

The west pad well will be tied into the central pad, where the gas processing and compression facilities will be located. The west and central pads are about four miles apart. ●

Contact Wesley Loy at wloy@petroleumnews.com

continued from page 1

SETTLEMENT CHALLENGE

Slope.

State officials were demanding development of the field, discovered in the 1970s, and the settlement lays out a schedule to that end.

Suing as a "citizen taxpayer," Walker argued the settlement was illegal and a bad deal for the state. He brought the action against the state attorney general and the Department of Natural Resources.

State lawyers filed a motion to dismiss Walker's suit, and Superior Court Judge Catherine Easter of Anchorage granted the motion on Dec. 7.

Suing as a "citizen taxpayer," Walker argued the settlement was illegal and a bad deal for the state. He brought the action against the state attorney general and the Department of Natural Resources.

The arguments

Asked whether Walker would appeal Easter's decision, Walker's attorney, Craig Richards, told Petroleum News on Jan. 8: "Bill has not yet decided what course to take."

Richards noted the court "did not reach the merits of the case," but instead determined Walker would need to take a different approach to challenge the Point Thomson settlement.

In her five-page ruling, Easter wrote: "To the extent Mr. Walker seeks to challenge whether the AG's entry into the Settlement Agreement was constitutional, he must bring an original action because an administrative appeal is not the proper forum for such a claim."

Walker is a longtime supporter of Point Thomson development.

However, he questioned the legality of the Point Thomson settlement on numerous levels. State officials failed to put the deal out for public comment, and failed to obtain legislative approval for some provisions, Walker said. He further contended the agreement contained no firm work commitments, and that Point Thomson leaseholders could choose a wasteful development option to exploit the field's rich gas reserves while leaving valuable liquids behind.

His attorney, Richards, argued Walker had the right to appeal the Point Thomson settlement under the Administrative Procedure Act and DNR regulations.

The state, however, argued the attorney general has "broad authority" to settle litigation, that the Point Thomson settlement was not subject to challenge, and that the court lacked jurisdiction to hear Walker's 'purported' administrative appeal.

The judge's holding

Easter agreed with the state that the court lacked jurisdiction over Walker's appeal.

She held that Attorney General Michael Geraghty entered into the Point Thomson settlement under executive discretion, and DNR Commissioner Dan Sullivan's signature on the deal was "not an appealable decision."

"Therefore, there is no legal basis to challenge the Settlement as an administrative appeal," the judge said.

State officials say the Point Thomson settlement will force ExxonMobil and its partners to either develop the field or lose the acreage. Construction is expected to begin this winter, with numerous contractors involved.

Sullivan was pleased with the court's dismissal of Walker's case.

"Why anyone would sue to shut down hundreds of jobs at Point Thomson is beyond me," Sullivan told Petroleum News in a Jan. 9 interview.

—WESLEY LOY

Contact Wesley Loy at wloy@petroleumnews.com

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Oil Patch Bits

GCI Commercial Services launches cloud data service

General Communication Inc. said Jan. 8 that it is announcing cloud computing services for business customers. GCI Cloud Services represents a new generation platform, enabling businesses to rapidly provision and deploy computing resources and access data applications anytime, anywhere.

"The mission of GCI Cloud is two-fold: Make Alaska-based computing resources available to Alaska enterprises, and provide them the flexibility and support they need to do what they do best — growing their businesses," said Ron Duncan, GCI's president and CEO. "We're excited to bring this service to our customers."

The Cloud is an approach to computing that uses a shared pool of configurable resources to provide convenient, on-demand, virtual network infrastructure or software utilized as an ongoing monthly service. Moving into the GCI Cloud enables easy access to virtual hardware and software through an Internet connection which allows businesses to pay for their IT resources at a low monthly rate — rather than investing in expensive IT infrastructure such as servers, hard drives and software application licenses.

GCI's Data Services Center brings data-center technologies and services together by offering space, power, and bandwidth in a redundant and secure location. GCI's scalable data center also allows businesses to use only what they need when they need it. This highly adaptable system lets GCI provide services that can quickly and efficiently support any growing business's needs.

Yacavone joins Crowley as VP of sales and chartering

Crowley Maritime Corp. said Jan. 2 that Matt Yacavone has joined the company as vice president of sales and chartering for its petroleum services team. He will be domiciled in the company's Jacksonville headquarters and report to Rob Grune, senior vice president and general manager, petroleum services.

Yacavone, who assumed his new position Jan. 7, will be responsible for the planning and direction of sales and chartering initiatives, overseeing development of policies and procedures, coordinating and negotiating customer contracts and developing business relations, particularly in the company's articulated-tub barge, ATB, and tanker programs.

"We are very pleased to have Matt join our team here in Jacksonville," said Grune. "He has a strong track record cultivating mutually beneficial business relationships with core customers in the petroleum industry. Matt also brings a wealth of operational knowledge and experience to Crowley, which is of paramount importance to our customers as we ensure compliance with all laws, regulations and internal core requirement for safety, environmental protection and business ethics."

see **OIL PATCH BITS** *page 29*

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

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

continued from page 1

DECISION TIME

it would feed into the Trans Alaska Pipeline System to Valdez.

The grand objective for the proponents is to eventually carry up to 5 million barrels per day on a twin-track system that would allow 12 trains per day to deliver crude to super tankers at Valdez, with each train of 240 cars carrying about 153,000 barrels.

Vickers said G7G has been in discussions over the past two years with governments in Alberta, British Columbia, the Yukon and Alaska to outline its proposal and has met with the Alberta Energy Department's strategic initiatives team.

He said the overriding impetus behind the G7G plan is to "keep supertanker traffic off Canada's pristine West Coast."

Pressure for new markets

Alberta, faced with a possible budget deficit of C$3 billion in the current fiscal year, and the industry are under pressure to open up new markets beyond North America to receive Brent-based pricing for their product and overcome entrenched opposition from First Nations, environmentalists and landowners to the plans for new pipelines from Alberta to the U.S. Gulf Coast, eastern Canada and the U.S. and tanker ports at Kitimat, Prince Rupert and Vancouver on the British Columbia coast.

Alberta Energy Minister Ken Hughes has ranked the effort to secure new markets as one of the most important challenges facing his province.

"The strategic imperative is that we get our products to the ocean so that we can obtain global prices," he said.

"The solutions are additional pipelines to the West Coast, to the East Coast and to the Gulf Coast and also train-car delivery of bitumen and oil products to the coast."

Century-old dream

The bid for the G7G rail link is a revival of a century-old dream and studies commissioned in 2005 and 2007 by the Alaska and Yukon governments to build a resource-based line tying Alaska with Canada and the Lower 48 to import and export a variety of goods.

That work concluded the idea could succeed based on the movement of containers and trains carrying products such as iron ore, coal, base metals, grains and fertilizer, making remote resource exploration and development more feasible.

Vickers said the "whole reason for our (crude oil) project is to keep super tanker traffic off Canada's pristine West Coast."

He said studies have "demonstrated that a rail link to Alaska is a viable alternative to the oil pipelines currently being planned across British Columbia … and will avoid many of the environmental risks associated with current pipeline proposals."

"Diversifying markets for Canadian oil is an important challenge, but we need to achieve this goal in the most environmentally and socially responsible way possible," Vickers said.

C$10.4 billion estimate

He noted that the preliminary cost estimate of C$10.4 billion for a double-track Alberta-Alaska rail link (C$8.4 billion for a single track to handle 1.5 million bpd) compares more than favorably with the price tags of C$5.5 billion for Enbridge's 525,000 bpd Northern Gateway project and the C$4.1 billion to add 450,000 bpd to Kinder Morgan's existing 300,000 bpd Trans Mountain pipeline — both seeking to open new markets for oil sands bitumen in Asia.

Vickers said that if the feasibility study provides the groundwork for filing a regulatory application, the proposal would likely involve a twin-track system, with the rail service provided by an existing or a new company.

> *The "whole reason for our (crude oil) project is to keep super tanker traffic off Canada's pristine West Coast."* **—G7G Director Matt Vickers**

G7G estimates that producers would pay C$6-C$8 per barrel to ship by rail, compared with the C$5 Northern Gateway proposes to charge.

Vickers also noted that Alaska tribes and Canadian First Nations affected by the rail plan have given their full support to the feasibility study, but emphasized he did not presume to translate that into aboriginal support for the project until a rail route has been selected.

He said that would come only if the feasibility study clears the way for G7G to proceed with "two years of full-blown community consultation."

First Nations support concept

Following several months of negotiations, Simon Mervyn, chief of British Columbia's Na-cho Nyak Dun, said in a statement First Nations "fully support the concept because, in reality, if we don't take the initiative, somebody else will."

Vickers said there has been only limited contact so far with oil producers, including a brief meeting with officials at Suncor Energy, the largest oil sands producer.

He said Suncor indicated its position on the use of rail has changed over the last six to 12 months since the rapid expansion of rail shipments out of the Bakken region.

Simon Dyer, policy director at the Alberta-based Pembina Institute, told the Edmonton Journal that moving bitumen by rail comes with risks that will need to be evaluated.

"Transporting dangerous goods by rail has a higher frequency of incidents than pipeline, (thought) pipeline spills tend to be of a larger magnitude," he said.

G7G has selected the global engineering firm Aecon Canada, which participated in the 2005 and 2007 studies and helped prepare a scoping document, after holding discussions with firms such as SNC-Lavalin, Siemens and Worley Parsons.

Churchill a possibility

Meanwhile, the prospect of using Manitoba's grain terminal at Churchill for a trial oil shipment, offers a "competitive cost advantage to deliver oil to multiple destinations for a short period of time each year," said Jeff McEachern, executive director of the Churchill Gateway Development Corp., which has probed the idea with industry leaders in Calgary over the past six months.

"It is not a full solution, but it has an economic advantage. It's being looked at seriously because producers want optionality in how they transport their product to refineries and ease congestion in pipelines or rail service," McEachern said.

Churchill, which has been used to export Western Canadian grain since 1929, is also experiencing a longer ice-free season that could be extended with the use of icebreakers.

The idea has progressed to a feasibility study involving a range of companies, including Hudson Bay Railway and its partner Canadian National Railway, and oil producers in Alberta, Saskatchewan and Manitoba. ●

Contact Gary Park through publisher@petroleumnews.com

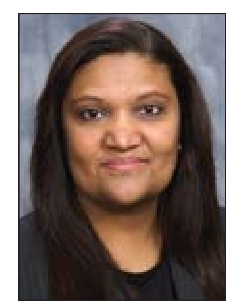
continued from page 28

OIL PATCH BITS

Yacavone most recently served as executive vice president of Gulf of Mexico and offshore units for Marquette Transportation in New Orleans. He began his career in 1989 as marine superintendent for McAllister Towing in Camden, N.J., upon his graduation from the U.S. Merchant Marine Academy at Kings Point. Yacavone later earned an MBA degree from Jacksonville University in 2003.

Baker Hughes names new chief information officer

Baker Hughes Inc. said Jan. 2 that Archana "Archie" Deskus, an executive with experience leading information technology functions within the aerospace, industrials and consumer products industries, will join the global oilfield services company as its chief information officer effective Jan. 14.


ARCHANA DESKUS

Deskus comes to Baker Hughes from Ingersoll-Rand, where she was vice president and CIO.

"Archie's deep IT executive leadership experience with large corporations across different industries will allow her to enhance our operational and business capabilities," Baker Hughes' President and CEO Martin Craighead said. "She will bring a great track record of building and developing high performing teams and of partnering with business leaders in executing large scale transformational projects."

Deskus began her career with Pratt & Whitney Aircraft as a computer systems programmer and analyst. She went on to become the VP and CEO for Carrier North America, followed by four years as senior VP and CIO at Timex Group. Deskus received her Bachelor of Science degree in business administration and management information systems from Boston University and her Master of Business Administration from Rensselaer Polytechnic Institute.

She replaces Clif Triplett, who spent four years as the company's CIO.

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continued from page 1

DIESEL POWER

broken it into two pieces and we've said there's a short-term … and then there's a long-term shortage, and we've recognized that they don't need to both have the same solution," Gibb said.

A reliable and certain solution is necessary for the short term, even although that solution may not be the cheapest option.

The use of diesel fuel for power generation would seem a low-risk means of ensuring that the lights stay on and buildings stay heated, as gas supplies from the Cook Inlet basin decline below demand levels.

"From a technology standpoint it's not very challenging. From a sourcing standpoint it's pretty realistic. And from a cost standpoint it's fairly well known," Gibb said in commenting that diesel is becoming the leading short-term contender.

And, although on an energy equivalent basis diesel may cost five times as much as gas, diesel power generation would, at least initially, represent a relatively small proportion of total generation, the diesel cost being diluted by the lower cost of power generated from gas.

Work to do

However, quite a bit of work remains to be done to clarify all the issues involved in diesel usage.

Lee Thibert, senior vice president of Chugach Electric Association, told Petroleum News that neither the Beluga power station on the west side of Cook Inlet nor the new gas-fired power station being completed in south Anchorage can currently run on liquid fuel. If the utilities move ahead with the diesel fuel option, one of the power plants in the new south Anchorage facility would probably be converted for liquid fuel use. Municipal Light & Power can already use diesel in its Anchorage power station. Golden Valley Electric Association in Fairbanks also has diesel generation capacity, with the possibility of shipping electrical power south on an electricity intertie that connects with Anchorage.

All options open

Looking into the longer term, which Gibb characterized as 15 years into the future, the utilities are still considering all possible options, including the import of LNG or CNG by ship from out of state. The longer-term arrangements would take over from the short-term solution, once those longer-term arrangements are in place. And in evaluating the long-term solutions, the utilities are assuming that the gas shortage will level out after 2020 as new Cook Inlet gas fields come on line following the resurgence of interest in Cook Inlet exploration.

Asked whether the implementation of a short-term solution to the gas shortage could provide a couple of years of breathing space, to see whether new gas fields in the Cook Inlet basin would bring on line sufficient gas to avert a long-term gas supply shortage, Gibb said that unfortunately an early decision will be needed for an option to import gas.

Any import option will require a commitment to the building of the necessary ships, with a two-year window involved in the ship construction, he said. And, with production decline rates from the basin at about 20 percent per year, drilling out of the supply shortage would be tough.

"The (gas production) declines that we're seeing here … there's a serious question … as to whether you can run fast enough," Gibb said. "If you don't find that mother-lode field that is all of a sudden just an heroic solution, it's very, very difficult to look at a means whereby you can drill your way out of this problem."

> *"What we've done on this project very recently is we've broken it into two pieces and we've said there's a short-term … and then there's a long-term shortage, and we've recognized that they don't need to both have the same solution."* **—Robert Gibb, associate director of Navigant Consulting**

North Slope gas

The possibility of trucking LNG from the North Slope is on the table, but this option would require hundreds of LNG trucks to travel down the Haul Road from the Slope every day, with gas supplies coming to a halt if for some reason the road had to be closed, and with the possibility of weather causing delays in truck movements.

"Logistically, it may be very, very challenging," Gibb said.

Gibb also addressed the question of an in-state gas line from the North Slope as a long-term gas supply solution for Southcentral, saying that at the moment the pipeline option is uncertain. If the pipeline is built, it would be necessary to look at the comparative economics of obtaining gas by this means, with the possibility of incurring the cost of backing out of the gas import arrangements, or extending the costly short-term power generation solution until the pipeline is completed.

Western Canada

And, whether in the form of LNG or CNG, imported gas would likely come from western Canada, with a purchase price linked to North American gas markets rather than to the price of LNG in, say, Japan. At present there is no practical source for the LNG or CNG from the West Coast of the United States, and shipping the product from a U.S. port would involve complications around the Jones Act, the statute that requires the use of U.S. ships for freighting between U.S. ports.

The utilities had been veering towards the import of CNG as an apparently simpler and more cost effective solution than LNG, although both of these long-term import solutions require dedicated ships. In fact, the utilities are close to determining the best shipping arrangement for the CNG option, Gibb said.

LNG

But the utilities have realized that they need to take a closer look at LNG — one LNG provider has what appears to be almost a custom fit to what is needed, he said. In fact there is an LNG option that presents the possibility of a short-term solution, he said. And there are technical challenges with CNG, including the construction of some necessary equipment.

"We do have a CNG answer, but there's not a reason to move forward with it yet," Gibb. "LNG is beginning to look more and more like, at least, a competitive solution."

The facilities for importing the CNG or LNG would probably be located at the port of Nikiski on the Kenai Peninsula, to take advantage of the existing dock infrastructure there. But, unlike the use of diesel fuel for power generation, there would be a significant permitting requirement. And either import option, because it would involve the movement of gas across the U.S. border, would require a presidential permit, a source of some project uncertainty, Gibb said.

—ALAN BAILEY

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continued from page 1

INTERIOR ASSESSMENT

tial for reducing our dependence on foreign oil and creating jobs here at home and the administration is fully committed to exploring for potential energy resources in frontier areas such as the Arctic," Salazar said. "Exploration allows us to better comprehend the true scope of our resources in the Arctic and to more fully understand the nature of the risks and benefits of development in this region, but we also recognize that the unique challenges posed by the Arctic environment demand an even higher level of scrutiny."

Safety No. 1 priority

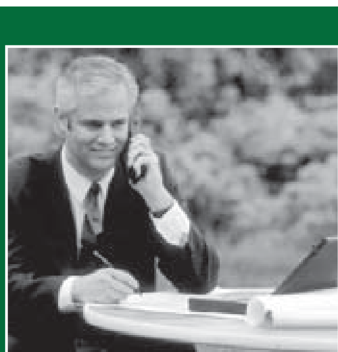
James Watson, director of the Bureau of Safety and Environmental Enforcement, said that his agency makes safety its number one priority and expects the highest level of performance from operators in the Arctic.

"As we oversee historic domestic drilling, BSEE will continue its unprecedented oversight of drilling activities in the Arctic and we will continue to hold anyone operating in public waters to the highest safety and environmental standards," Watson said.

In the wake of the Deepwater Horizon disaster in the Gulf of Mexico, Interior has put in place a series of new measures which the agency says will protect the environment and workers on offshore drilling rigs. New safety measures include heightened drilling safety standards to reduce the risk of a loss of well control, and a new focus on oil containment capabilities in the event of an oil spill, Interior said.

—ALAN BAILEY

Contact Alan Bailey at abailey@petroleumnews.com



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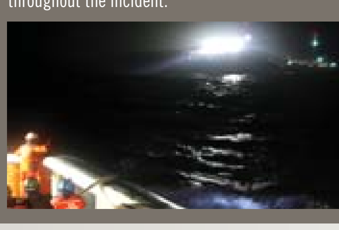
UNIFIED COMMAND

2012-13 KULLUK TOW INCIDENT RESPONSE AND RECOVERY TIMELINE

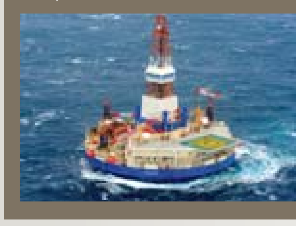
The Kulluk, Shell's conical drilling unit used in the company's 2012 exploratory season, departed Dutch Harbor, Alaska on Dec. 21, 2012. The rig was in tow by the Aiviq, en route to Seattle for scheduled winter maintenance.

THURSDAY, DEC. 27
- Aiviq's tow connection parts and the Kulluk drifts before an emergency tow line is established.

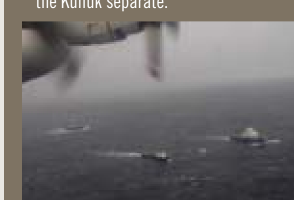
FRIDAY, DEC. 28
- Aiviq loses power. Generators are activated to help avoid significant drift.
- Support vessels are dispatched to provide aid.
- Coast Guard, State of Alaska, Shell and Edison Chouest Offshore establish a Unified Command in response to the Kulluk Tow Incident. During the next few days, Unified Command grows to more than 700 responders.
- Unified Command initiates calls with Old Harbor, Kodiak community and fishing industry representatives. Meetings and calls continue daily throughout the incident.



SATURDAY, DEC. 29
- Coast Guard safely evacuates the 18-person Kulluk crew.



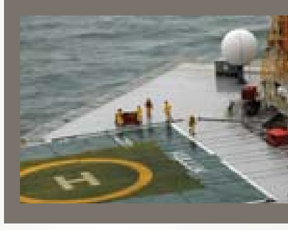
SUNDAY, DEC. 30
- The lines connecting Aiviq and Nanuq to the Kulluk separate.



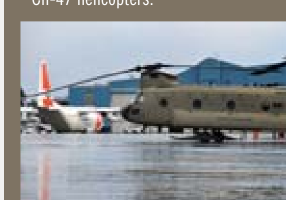
MONDAY, DEC. 31
- Strong winds and rough seas cause the Kulluk to ground on the northern tip of Ocean Bay, located on the southeast side of Sitkalidak Island, Alaska.

TUESDAY, JAN. 1, 2013
- U.S. Sen. Lisa Murkowski (R-Alaska) meets Unified Command to discuss the priorities and challenges associated with Kulluk Tow Incident response-and-recovery efforts.

WEDNESDAY, JAN. 2
- The salvage assessment team reports the Kulluk remains stable, with no sheen visible; however, there is some wave damage to the topsides and emergency and service generators are damaged.



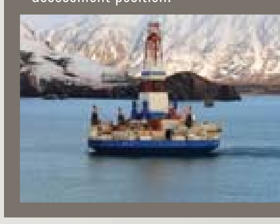
FRIDAY, JAN. 4
- 14 vessels are mobilized for response efforts. U.S. Army provides two Chinook Ch-47 helicopters.



SATURDAY, JAN. 5
- Boom is deployed to Kodiak Island as a precautionary measure. International Bird Rescue is activated to assist in bird rescue programs and protected species observers are deployed on-scene.
- Coast Guard delivers salvage teams aboard the Kulluk to prepare for recovery operations.

SUNDAY, JAN. 6
- Aiviq, connected by tow, successfully refloats the Kulluk and begins towing it Kiliuda Bay.

MONDAY, JAN. 7
- The Kulluk safely arrives in Kiliuda Bay and is anchored to its safe harbor assessment position.



THURSDAY DECEMBER 27 · FRIDAY DECEMBER 28 · SATURDAY DECEMBER 29 · SUNDAY DECEMBER 30 · MONDAY DECEMBER 31 · TUESDAY JANUARY 01 · WEDNESDAY JANUARY 02 · THURSDAY JANUARY 03 · FRIDAY JANUARY 04 · SATURDAY JANUARY 05 · SUNDAY JANUARY 06 · MONDAY JANUARY 07

continued from page 1

KULLUK REFLOAT

when floating.

The unified command for the incident, with representatives from Shell, the U.S. Coast Guard, the Alaska Department of Environmental Conservation and Kodiak Island Borough, had also communicated with local communities and had secured access to the shoreline in the vicinity of the grounding. The unified command also communicated with the Prince William Sound and Cook Inlet Regional Citizens Advisory Councils.

At high tide

The refloating operation, carried out at high tide, initially involved applying tension to the towline from the Kulluk, Shell's Sean Churchfield, incident commander for the response, told a press conference called on Jan. 7. As the high tide approached, the salvage crew increased the tension on the line, with the Kulluk apparently coming off its grounded position fairly easily.

The Nanuq, Shell's oil spill response vessel, used infrared equipment to monitor for any leakage of diesel fuel or other hydrocarbon material. Steve Russell, the state on-scene coordinator, told the press conference that no hydrocarbons had been detected in the water around the drilling vessel.

The Aiviq, with assistance from a tug, the Alert, towed the Kulluk about 45 nautical miles to a safe anchorage in Kiliuda Bay, on the coast of Kodiak Island, arriving in the bay at around 10 a.m. on Jan. 7. The unified command deployed a total of four tugs, all with towing capabilities, to support the operation, Churchfield said.

The Coast Guard cutter Alex Haley escorted the tow. The response team arranged the staging of oil spill response equipment offshore, nearshore and onshore to guard against the possibility of a fuel leak. In addition to the Nanuq, the oil spill response vessel, the Perseverance, based in Cook Inlet, attended the tow.

ROV inspections

Two days later remote operated vehicles were inspecting the Kulluk's hull as part of a detailed assessment of the vessel's condition, as a precursor to a decision on when, how and where to move the vessel, and on whether any repairs are needed before the move. There does not appear to be any leakage from the vessel, the U.S. Coast Guard has said.

Assessment crews, along with representatives from the Native corporation for Old Harbor, the village near the grounding site, have been surveying the area near the grounding to enable the recovery of survival and rescue boats and other debris from the Kulluk, the Coast Guard says. Apparently four survival boats and one rescue boat were dislodged from the Kulluk and are on the shore. Each of the survival boats has a 48-gallon diesel tank. Two of these tanks are known to have been damaged and one tank could not be accessed, to determine its condition. The assessment crews will determine if any fluids have been released on the shoreline and prepare any necessary mitigation measures, the Coast Guard said.

Coast Guard investigation

Meantime, on Jan. 8 Rear Adm. Thomas Ostebo, commander of the U.S.

see **KULLK REFLOAT** *page 32*

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continued from page 31

KULLUK REFLOAT

Coast Guard 17th District, ordered a formal marine casualty investigation of the Kulluk grounding. A Coast Guard investigating officer will lead the investigation and the Bureau of Safety and Environmental Enforcement and the National Transportation Safety Board will participate as technical advisors. On Jan. 3 the Coast Guard had said that it was deploying an investigation team for the Kulluk incident.

The Coast Guard investigates all reportable marine casualties, but only conducts an investigation involving a formal board for what the agency considers to be a major incident.

Lt. William Albright of the Coast Guard told Petroleum News Jan. 9 that a formal investigation of the type that is now under way is conducted whenever there is a major marine incident, where the Coast Guard believes that it can learn how to prevent a similar incident occurring in the future. The idea is to find the causes of the incident, and any contributing factors, and then make any appropriate changes to the Coast Guard regulations, Albright said.

There have been four formal Coast Guard investigations in the past 10 years in Alaska, the last one being triggered by the sinking of the Monarch supply vessel in 2009 at an offshore oil platform in Cook Inlet.

Begich wants review

On Jan. 8 Sen. Mark Begich, chairman of the Senate Subcommittee on Oceans, Atmosphere, Fisheries and the Coast Guard, called for a "critical review" of the Kulluk grounding and announced his intention to hold a meeting in Anchorage to take a closer look at the incident.

In a letter to Coast Guard Commandant Admiral Robert Papp and Shell Oil Co. President Marvin Odum Begich emphasized the importance of outer continental shelf oil development.

"Moving ahead with the Arctic drilling program is critical to Alaska's economic future," Begich wrote. "While this incident notably involves marine transportation and not oil exploration or drilling, we must quickly answer the many questions surrounding the Kulluk grounding and improve any regulatory or operational standards as needed to ensure this type of maritime accident does not occur again."

Enviros want a stop

Environmental organizations, adamantly opposed to oil exploration on the Arctic outer continental shelf, have cited the Kulluk grounding as evidence that oil drilling in the Arctic offshore poses unacceptable environmental risks.

"The implications of this very troubling incident are clear — Shell and its contractors are no match for Alaska's weather and sea conditions either during drilling operations or during transit," said Lois Epstein, Arctic program director for the Wilderness Society and a member of the Department of the Interior's Ocean Energy Safety Advisory Committee. "Shell's costly drilling experiment in the Arctic Ocean needs to be stopped by the federal government or by Shell itself, given the unacceptably high risks it poses to both humans and the environment."

Shell comments

Shell's Odum, in a Jan. 7 statement, said that Shell would participate in the Coast Guard investigation of the Kulluk grounding and that it was too early to determine the impact of the grounding on Shell's exploration plans.

"We undertake significant planning and preparation in an effort to ensure these types of incidents do not occur. We're very sorry it did," Odum said. "Since the grounding, Shell has worked with all parties in the unified command structure to ensure a safe outcome and to protect the maritime environment in the vicinity of the grounded vessel. Thanks to the professionalism, dedication, and skill of all those involved in the recovery effort, I'm pleased to say those objectives have been met with no significant injuries and no environmental impact." ●

Contact Alan Bailey
at abailey@petroleumnews.com

continued from page 26

PIPELINE BILL

mercially viable, the company told FERC.

AGIA license amended

In his January 2012 State of the State address, Parnell laid out benchmarks for achieving a gas line based on LNG — beginning with resolution of the Point Thomson litigation (a settlement was announced March 29) and alignment of the North Slope producers on commercializing natural gas under the AGIA framework (announced March 30).

On May 2 the state approved an amendment to the AGIA license calling for initial work on an LNG project to be completed by September with an open season by the end of the year.

The governor's benchmarks included hardened numbers for an LNG project and an associated work schedule by the end of the third quarter.

On Oct. 1 the aligned commercial group — BP, ConocoPhillips, ExxonMobil and TransCanada — told Parnell in a letter that the current cost estimate for an LNG project was $45 billion to $65 billion in 2012 dollars.

The project would include a gas treatment plant either on the North Slope or in Southcentral; a 42-48 inch pipeline; a three-train liquefaction plant; LNG tanks and a terminal.

The companies said they looked at 22 potential sites for the liquefaction plant, including "Cook Inlet, Prince William Sound and other Southcentral sites," with a footprint of 400 to 500 acres. The gas treatment plant would have a footprint of 150 to 250 acres and be among the largest such facilities in the world.

The pipeline, some 800 miles in length, would have a capacity of 3-3.5 billion cubic feet per day and include five in-state off-take points for 300-350 million cubic feet per day.

In an Oct. 3 letter Parnell said the information provided met his benchmark of hardening numbers and identifying a gas project by the end of the third quarter, and also addressed another benchmark of completing discussions with the AGDC, the in-state gas project, on the potential to consolidate the work of the two projects.

Challenges

In a diagram of key decision points accompanying their Oct. 1 letter the companies indicated that for the project to proceed from concept selection to pre-FEED (front-end engineering and design) a competitive oil tax environment, predictable and durable LNG project fiscal terms and resolution of AGIA issues would be required.

In a footnote to the project's phases the companies listed items which could extend the duration of the phases, including: "protracted resolution of fiscal terms, permitting and regulatory delays, legal challenges, changes in commodity market outlook, time to secure long-term LNG contracts, labor shortages, material and equipment availability, weather, etc."

The companies said that while concept selection technical work is reaching closure, "additional commercial agreements as well as support from the State of Alaska will be required in order to progress this world-class opportunity."

Some of the challenges the companies list — "cost, scale, long project lead times" and reliance on production facilities supporting declining fields — aren't directly things the state can address. Some required permits would come from the state, others from the federal government.

The governor had said in January that if his milestones were met, "the 2013 Legislature can take up gas tax legislation designed to move the project forward."

But the companies' letter made it pretty clear that not just gas taxes are at issue.

Existing oil production facilities "need to be available over the long-term for producing the associated gas for an LNG project. For these reasons, a healthy, long-term oil business, underpinned by a competitive fiscal framework and LNG project fiscal terms that also address AGIA issues, is required to monetize North Slope natural gas resources." ●

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continued from page 5

GOLDSMITH ANALYSIS

the central North Slope; $1.7 billion from shale oil; $1.7 billion from viscous and heavy oil; and $1.7 billion from the outer continental shelf.

The analysis shows zero revenue from the Arctic National Wildlife Refuge and the National Petroleum Reserve-Alaska.

The state long has pursued a multi-billion-dollar natural gas pipeline to develop the vast stranded gas reserves on the North Slope, chiefly in the Prudhoe Bay and Point Thomson fields.

Goldsmith's analysis marks down $11.7 billion in net present value from natural gas produced over the 50-year period. The gas is "assumed to be monetized through a pipeline to tidewater," exporting 3.5 billion cubic feet per day starting in 2023.

Natural gas, Goldsmith says, is obviously not an answer for sustaining growth in state spending.

He further notes that new broad-based income and sales taxes would only postpone, not eliminate, the fiscal crunch.

Goldsmith advocates a "maximum sustainable yield" approach, where the state builds a petroleum nest egg, invests the savings and follows a disciplined spending regime. ●

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