Petroleum News

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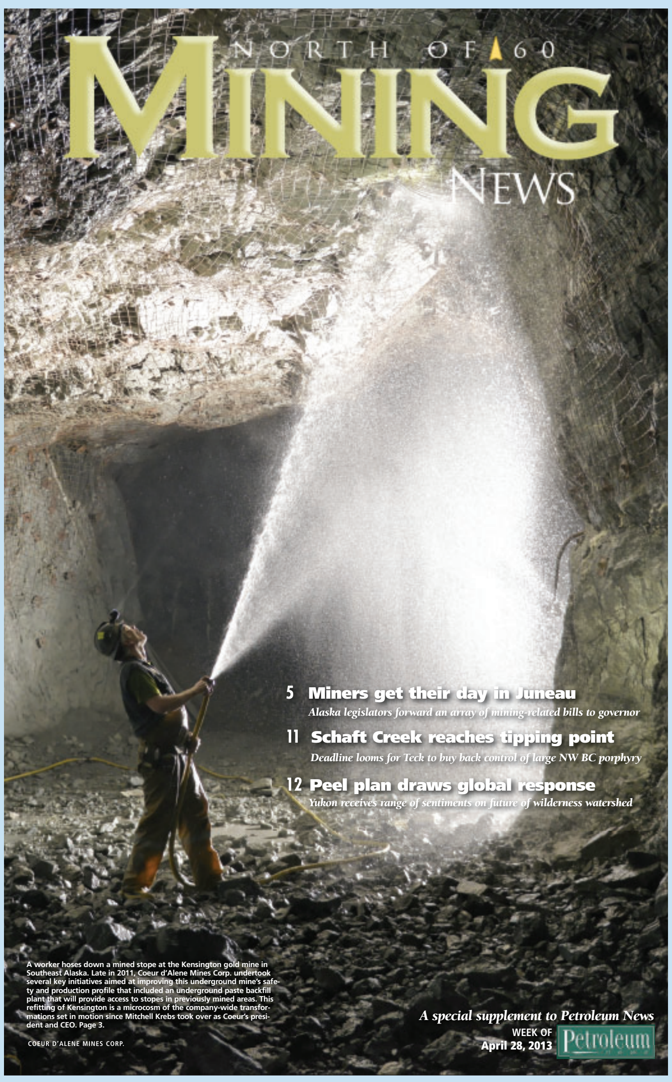
April Mining News inside



The April issue of North of 60 Mining News is enclosed.

Linc flow testing Umiat well, expects results in early May

Linc Energy is flow testing a well at the Umiat field, the company said on April 23.

A local subsidiary of the Australian independent is flow testing the Umiat No. 18 well and expects to have results sometime in early May, according to the company.

"I am delighted with this development, to be flowing oil at Umiat is a major milestone for Linc Energy. I look forward to announcing the results of the flow tests in the next two weeks," Linc Energy Chief Executive Officer Peter Bond said in a prepared statement.

see **UMIAT TESTING** *page 21*

Canadian Beaufort drilling years away, possibly late this decade

Pieces continue to be shuffled and moved into place in a long process leading to the possible resumption of oil and natural gas exploration in the Canadian section of the Beaufort Sea, but actual drilling will likely have to wait until late this decade.

The most eagerly awaited announcement will come from a joint venture by operator Imperial Oil, ExxonMobil and BP, which expects to file a project description and environmental impact statement, EIS, with regulators later this year to drill one or more wells.

Imperial said a "decision to proceed with an exploration drilling operation in the Beaufort Sea would require a significant financial commitment" by the partners.

"Many factors would have to be considered in making a decision, including regulatory approvals and resolution of issues such as (the National Energy Board's) equivalency to same-season

see **CANADIAN BEAUFORT** *page 18*

EXPLORATION & PRODUCTION

Three for three

Repsol announces three 'good quality hydrocarbon discoveries' at Qugruk

By ERIC LIDJI
For Petroleum News

Repsol has announced three "new good quality hydrocarbon discoveries" from its recently completed North Slope exploration program, the company said on April 23.

The Qugruk No. 1 and Qugruk No. 6 wells produced two hydrocarbon shows with "encouraging results during production tests," and the Qugruk No. 3 well identified hydrocarbons "at multiple levels," according to the Spanish supermajor. Repsol drilled Q1 to around 8,179 feet, Q3 to around 10,544 feet and Q6 to around 8,651 feet.

The wells are in the fairway between the Oooguruk unit and the Colville River unit.

The wells are in the fairway between the Oooguruk unit and the Colville River unit.

"These results are encouraging for the future development of the resources discovered," the company said, calling the North Slope an "oil-rich" and "especially promising" area.

Repsol operates the program and holds a 70 percent working interest in the leases. The Armstrong Oil & Gas subsidiary 70 & 48 LLC holds a 22.5 percent working interest and the Denver independent GMT

see **QUGRUK WELLS** *page 22*

EXPLORATION & PRODUCTION

Conoco: $543M in 1Q

Announces Cassin discovery, talks investments, analyzes Chukchi exploration

By ERIC LIDJI
For Petroleum News

ConocoPhillips reported adjusted earnings of $543 million from its Alaska operations in the first quarter, down quarter-over-quarter and year-over-year on declining production.

The most prolific oil company in Alaska saw its adjusted earnings in the state drop 8.7 percent from the fourth quarter of 2012 and 12.4 percent from the first quarter of 2012.

Companywide, ConocoPhillips earned $2.1 billion in profits in the first quarter.

During a call for investors on April 25, ConocoPhillips also announced a discovery at its Cassin prospect in the National Petroleum Reserve-Alaska, but offered few details.

The call also yielded numerous questions about whether and how ConocoPhillips would increase investments in Alaska in the wake of recent changes to the fiscal regime.

While noting its recent decision to bring an additional rig to the Kuparuk field, company officials said ramping up production at existing drill sites might be possible within the next few years, but adding drill sites would take longer because of Arctic lead times.

"Our first-quarter earnings continue the general trend where under ACES, ConocoPhillips Alaska pays more than twice as much in taxes and royal-

see **CONOCO EARNINGS** *page 23*

PIPELINES & DOWNSTREAM

A calamity averted

Pump station upgrades said to prevent long Alaska pipeline shutdown in 2011

By WESLEY LOY
For Petroleum News

The operator of the trans-Alaska oil pipeline has been working for years to modernize pump stations along the 800-mile route.

The chief objective of this "strategic reconfiguration" program is to save costs.

But it has yielded other important benefits, says operator Alyeska Pipeline Service Co.

After an oil leak forced a pipeline stoppage in January 2011, new pump station equipment helped avert a shutdown of unprecedented length, a top Alyeska manager said.

The problem facing Alyeska was the rapid chilling of idle oil inside the pipeline. New pumps and power units installed as part of strategic reconfiguration

ALASKA DEC

Pump Station 1 and the storage tanks used to hold oil field production while the trans-Alaska pipeline is shut down.

were able to restart the flow, something the old "legacy equipment" probably couldn't have done, said John Baldridge, Alyeska's senior director of pipeline

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ON THE COVER

● GOVERNMENT

Sen. Kevin Meyer on citizen legislators

Anchorage Republican, who works for ConocoPhillips when he's not in Juneau, says scrutiny at new heights in this year's session

By STEVE QUINN
For Petroleum News

One day after the Legislature adjourned, Sen. Kevin Meyer was on a plane to Anchorage where his other job awaited him: that as ConocoPhillips employee who sells and distributes surplus goods.

His work with ConocoPhillips has been no secret and routinely prompted him to declare a potential conflict of interest during floor votes in each of his 13 years in office, first with the House and now with the Senate.


SEN. KEVIN MEYER

He said he's accustomed to scrutiny that comes with holding down both jobs, but it reached new heights during the most recent of what seems to be ongoing oil tax debates that dates to 2006.

This time it was for his role as co-chairman of the Senate Finance Committee, the third of three Senate committees to review SB21, the oil tax reform bill.

The Anchorage Republican has been around for tax changes in the 2006 Petroleum Production Tax debate and the 2007 Alaska's Clear and Equitable Share discussion.

He served in the House then, before moving to the Senate in time for a reprised bill, which failed last session.

That changed this year when the Legislature passed Senate Bill 21 amid the criticism of Meyer and Sen. Pete Micciche, another Conoco Phillips employee, overseeing committee's hearing the bill.

Meyer spoke of the scrutiny and of the Legislature's resource development accomplishments with Petroleum News one week after session ended.

Petroleum News: You've said that you're received more pushback and criticism for your work with ConocoPhillips conflicting with your work as a legislator and co-chairman of the Finance Committee. What do you believe that's happened?

Meyer: I'm not sure. If you recall we were dealing with oil taxes last year. I don't think the issue came up once that I have a conflict of interest because I've worked at Conoco Phillips. I don't recall any reporters reporting on it. I certainly didn't get any emails or phone calls like I am this year. In fact the same groups that are upset with me are groups that endorsed me and supported me during the campaign last year, the Backbone group. They were running media ads with Bettye Davis and (Bill) Wielechowski, saying these guys are part of a bipartisan coalition. We support them. Six months later they are saying, "he's got a conflict. He's got the oil tax all wrong."

I'm not sure what changed in the last six months other than the politics. That is what I think this is all about. Last year I was part of a bipartisan coalition led by Democrats. This year I'm part of a bipartisan coalition that's led by Republicans. When you are dealing with such a critical issue to our budget and the overall health and wealth to our state, then we've got to take the emotion and the politics out of it and just look at the facts.

This year we had three different consultants and one of them, PFC Energy, was the same consultant we had under the bipartisan coalition last year. Everybody seemed to respect them and like them. It's the same consultant advising us this year that we are just not competitive. We have to adjust our oil tax structure to become competitive. I still don't know if what we ended up with is going to be enough, but it's certainly a lot better than what it was under ACES.

Petroleum News: The only difference between now and last year under the coalition is that you're co-chair and you were in the House as well, correct?

Meyer: When we were doing PPT in 2006 and ACES the next year, I chaired the House Finance Committee. One difference was Mike Chenault was the other co-chair and I turned the gavel over to him. I offered to turn it over to (Sen.) Pete Kelly and his response was you know a lot more about oil and gas than I do, so you go ahead and chair it. So I did. As you recall, once it got on the floor — and it's really the floor vote that's binding, the one that really counts — you'll notice it was Sen. Fairclough that led the debate on oil taxes. It wasn't me.

I spoke to Mike Bradner who was speaker of the House back in the 1970s, and I asked him have you always dealt with conflict of interest this way: standing up and if somebody objects you have to vote. Mike Bradner, who was a Democrat and in the 70s it was pretty much a Democratic majority, he said they felt strongly that this way was the best way to do it. What was happening was people would ask to be excused saying they had a conflict and in reality they were trying to avoid a difficult vote. Both Republicans and Democrats want everybody on record.

The current system we have in place has been around for a long time. It's always a difficult issue. I know when I was on the Anchorage assembly we would stand up and declare our potential conflict of interest. Our colleagues would vote on it and it became very political. A person either thought, "well, he's on my side, so I'm going to say he doesn't have a conflict," or if someone thinks, "he's going to vote this way and I don't want him to vote, so I'll say he has a conflict." So there is not a good way to deal with conflict of interest. As a citizen Legislature, everybody is going to have conflicts. I think the way we deal with it is the best. You stand up, you declare it and then you vote. It's up to your constituents to decide whether or not they like how you voted or didn't vote. I've been in the Legislature 13 years and eight years on the Assembly before and people know my voting pattern and where I stand on various issues.

Q AND A

When I run for office, I always tell people where I work. To disenfranchise them and not let them have a voice down in Juneau would be unfair to 35,000 people. Now if you do the same thing to Sen. Micciche, now you're talking about 70,000 people. That would be like saying Fairbanks you're not going to have a say on oil taxes or Southeast, Alaska, you're not going to have a say. So, 70,000 people is an awful lot.

The oil industry is the main industry in Alaska and employs a lot of people.

The culture at ARCO, then ConocoPhillips, is to encourage employees to give back to the community and the state we work in. You're going to have folks who ultimately get involved in boards and commissions and eventually asked to run for office. I'm frankly surprised there are not more folks who work for the oil industry who are in elected positions. I think there isn't because they don't want to have to put up with the negative comments.

You know Sen. Micciche and I, we didn't decide one day we are going to run for office so we could vote on oil taxes.

Petroleum News: You had this prospective conflict reviewed several years ago, right?

Meyer: In 2008, I asked our ethics committee to make a ruling on the conflict of interest or not because some years it's not an issue and other years it is. If somebody tells me it's wrong, I won't do it any

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● PIPELINES & DOWNSTREAM

Boost for BC refinery plan

MOU from China's largest bank to organize syndicate of lenders, possibly engineering, construction advice for Kitimat refinery

By GARY PARK
For Petroleum News

China's largest bank has given a major lift to the dreams of newspaper publisher David Black to lead construction of the first new North American refinery in decades.

He signed a memorandum of understanding in Beijing that, if completed, will see the Industrial and Commercial Bank of China act as financial adviser, participate in "associated pipelines and other elements" and provide engineering and construction advice for the possible C$25 billion venture.

Black told reporters that ICBC views its role as "providing a fair amount of money themselves, but also organizing the club of banks that will provide all the debt money. They have the money, but they like to spread risk around like insurance companies."

ICBC said it was "very pleased to be working toward a comprehensive agreement to finance a refinery in Canada, which is planned to export refined fuels to China and other Asian countries."

Black said ICBC shares his goal of preferring to see the entire project financed through debt, rather than investors taking a stake in the assets.

No controlling interest

He said ICBC has agreed it will not seek a controlling interest in the refinery, the marine terminal, a pipeline or a tanker fleet.

Black said that in addition to organizing a syndicate of lenders, ICBC could also become an investor, but said negotiations have not advanced to the point of discussing how much ICBC is prepared to lend.

"These are big loans and one bank isn't going to take all the risk itself. They will spread it around. So what we need is a lead bank to organize that," he said.

Black told the Canadian Broadcasting Corp. that the MOU is a "non-binding letter of intent. There's a lot of negotiating to do. But I am very sure we'll get there."

Black said he is hoping to use his time in China to develop off-take deals with Chinese energy companies, including PetroChina and Sinopec, to buy fuels from the refinery.

His earlier hopes of using Swiss-based Oppenheimer Investments Group to serve as financing and marketing agent for his privately owned Kitimat Clean suffered a setback three weeks after that initial announcement in March with the sudden death of Oppenheimer co-founder Samuel Grossmann. However, Richard Cooke, Oppenheimer's senior managing director for the Americas and Africa, said in March that his firm had "the funding committed to do this project," although it is not clear whether Oppenheimer is still involved.

Refinery at C$15B-C$18B

Depending on the design of a refinery to process 550,000 barrels per day of diluted bitumen into transportation fuels, the facility could cost C$15 billion to C$18 billion. Other estimated costs include C$6 billion for a pipeline from the Alberta oil sands, although Black has suggested the crude could be delivered to Kitimat by rail, and C$1 billion for new ocean-going tankers.

No timetable has been set for Kitimat Clean to file applications for environmental and other regulatory approvals.

The proposal is supported by the British Columbia government, which is just as adamantly opposed to Enbridge's Northern Gateway project to transport 525,000 bpd of crude bitumen to a tanker terminal at Kitimat.

Black has argued that a refinery would create 3,000 permanent jobs, while Northern Gateway's plan to ship unrefined bitumen to Asia would generate few benefits for the province.

Black said his next moves include opening discussions with First Nations to explore "their concerns and discuss the opportunities" a refinery would present.

Chicago-based Navigant Consulting, in a report commissioned by the British Columbia government, said the refinery could sell fuels in China, India, South Korea and Japan "without major disruption to local spot markets." ●

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● PIPELINES & DOWNSTREAM

A connection agreement for Prudhoe Bay?

Field has never had a formal agreement with the trans-Alaska pipeline, but the replacement of transit lines may change that

By ALAN BAILEY
Petroleum News

In perhaps one of the more obscure outcomes of the replacement of corroded oil pipelines following a 2006 oil spill at the Prudhoe Bay oil field, the owners of the field may have to sign for the first time a formal connection agreement between the field and the trans-Alaska oil pipeline system, or TAPS. Apparently, with TAPS originally built to export oil from the Prudhoe Bay field before any other North Slope fields were developed, there has never previously been a formal agreement for the terms and conditions under which the field is connected to the pipeline.

But following major replacements of transit lines carrying oil to pump station 1 at the northern end of TAPS, in 2010 Alyeska Pipeline Service Co., the TAPS operator, applied to the Regulatory Commission of Alaska, or RCA, for a permit to connect Prudhoe Bay to the pipeline system; Alyeska also asked the commission to approve a proposed connection agreement between the field and TAPS — an approved connection agreement is a prerequisite for a connection permit.

Lost in history

Although the connection between the field and TAPS has been in existence for the entire life of TAPS, "for reasons not clear to (Alyeska), and lost in history, the TAPS owners and PBU (the Prudhoe Bay unit) have not previously entered into a connection agreement," Alyeska told RCA.

But the owners of the Prudhoe Bay field have objected to a clause relating to indemnification for economic losses in Alyeska's proposed connection agreement for the field. Consequently, the owners have argued that the connection agreement is not in fact needed, since the upgrades at the field only involved the replacement of pipelines upstream of the connection to TAPS, with the pre-existing TAPS connection remaining unaltered. The new transit lines do not come under RCA jurisdiction, did not require a construction permit and therefore do not require a connection agreement, the owners said.

However, John Wood, RCA administrative law judge, has proposed to the RCA commissioners that the commission should require an approved connection agreement for Prudhoe Bay, but that the connection agreement should not include the provision for the indemnification of economic losses.

Other agreements

Apparently all fields that have connected to TAPS since the startup of Prudhoe Bay have formal connection agreements. But, although a model connection agreement approved by RCA in 2003 for future use contains an indemnification clause, some North Slope field connection agreements contain a clause of this type while others do not.

Excluding the indemnification clause for economic losses from the agreement "is reasonable and does not grant an unreasonable preference or advantage, nor subject any person to an unreasonable prejudice or discrimination," Wood wrote.

Apparently, all fields that have connected to TAPS since the startup of Prudhoe Bay have formal connection agreements.

And the proposed new connection agreement for Prudhoe Bay appears reasonable, closely following the model agreement approved in 2003, even although the field has a previously existing connection with the pipeline system, he wrote. ●

Contact Alan Bailey at abailey@petroleumnews.com

LAND & LEASING

Potential Alaska state and federal oil and gas lease sales

Agency	Sale and Area	Proposed Date
DNR	Cook Inlet	May 8, 2013
DNR	Alaska Peninsula	May 8, 2013
DNR	Augustine Island Geothermal	May 8, 2013
DNR	Beaufort Sea Areawide	October 2013
DNR	North Slope Areawide	October 2013
DNR	North Slope Foothills Areawide	October 2013
BLM	NPR-A	fall 2013
BOEM	Chukchi Sea	May 2016
BOEM	Cook Inlet (special interest)	November 2016
BOEM	Beaufort Sea	May 2017

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

● ENVIRONMENT & SAFETY

Figuring the sounds in Arctic offshore

Scientists seek ways to estimate the environmental impacts of multiple sound sources as industrial and vessel activity builds up

By ALAN BAILEY
Petroleum News

While oil spill concerns often grab the headlines when it comes to potential environmental impacts from Arctic offshore oil exploration and development, worries about the possible effects of industrial noise on marine wildlife also figure high on the priority lists of those who plan, monitor or regulate offshore activities, and of those who hunt for marine mammals as a subsistence food source.

During this year's National Marine Fisheries Service Arctic Open Water Meeting, held in early March, several presentations focused on the tricky question of how to assess noise impacts on marine mammals, to achieve an appropriate balance between economic needs and environmental protection.

Noisy ocean

During a talk on the impacts of offshore seismic sound on marine mammals, Amy Scholik-Schlomer, acoustic coordinator in the National Marine Fisheries Service Office of Protected Resources, commented that, while marine mammals use sound for communication, navigation and prey detection, the ocean is inherently noisy, with sounds coming from both natural and manmade sources.

The Fisheries Service, while allowing activities vital to security and the national economy to take place, tries to address concerns about manmade noise becoming a threat to marine life, Scholik-Schlomer said.

Although mitigation measures enforced during seismic operations try to ensure that animals are not exposed to sound loud enough to cause hearing damage, there is a more general question of the impact of manmade sound on animal behavior, in situations where an animal is not directly injured by the noise but where behavioral changes may impact the animal's ability to reproduce, grow or even survive, she said.

Pervasive sound

And human sound can pervade the ocean.

In the mid-Atlantic people have recorded seismic sounds at distance of up to 4,000 kilometers from a seismic vessel, Scholik-Schlomer said. And in the Gulf of Mexico, where seismic sound can be near continuous, animal vocalization has been observed to change, although the reasons for the change are unknown, she said.

Simple vessel traffic can itself create noise problems. Scholik-Schlomer demonstrated a computer simulation of the underwater sounds from commercial shipping in the north Atlantic: This model suggests noise from the ships overwhelms or "masks" natural sounds used by North Atlantic right whales for 50 percent of the time, and sometimes for as much as 80 percent of the time, Scholik-Schlomer said.

Modeling technique

Melania Guerra, a scientist from Cornell University, described a new research program, evaluating a modeling technique for assessing the cumulative impacts of multiple sound sources in the Alaska Arctic offshore. The research program, with funding from BP and the involvement of the North Slope Borough, is developing a computer application that simulates the potential behavior of animals such as whales under different sound scenarios.

Given the complexity of the issues being addressed, the research program involves a working group of multi-disciplinary experts from a variety of backgrounds and affiliations, Guerra said.

Essentially, the group's approach involves deciding on a region and time period to assess, identifying all known significant sources of human ocean noise in that region and period, and then using the data to model the human "acoustic footprint," the pattern of both continuous and impulsive underwater sound that would permeate various parts of the region as a consequence of human activities.

The idea then is to assemble information about what is known about the ways in which an animal species responds to sound, so that the model can simulate animals' behavior as they swim through the acoustic footprint, enabling the scientists to assess any significant or adverse impacts from the human-generated noise.

Beaufort Sea test

As a test for its simulator system, the group decided on a case study loosely based on activities in the western Beaufort Sea during the summer open water season of 2008, Guerra said. And the group chose to use the system to assess the impact of the activities on the east to west migration of bowhead whales between Sept. 1 and Oct. 23 of that year, she said.

At that time five seismic surveys were in progress in the Beaufort Sea, with two surveys using powerful air guns and three using smaller air guns, Guerra said. In addition, two offshore islands had oil operations that created some subsea sound, and two barge tows were in progress, she said. The incorporation of sound characteristics from all of these sources into a marine sound propagation model enabled the simulation of the subsea acoustic footprint, as it developed over the time period under investigation.

To simulate the whale behavior, the scientists gathered data about what is known about how bowhead whales respond to sound, including Alaska Native traditional knowledge about the whales' behavior and sound avoidance responses. By plugging all of this information into the computer system the scientists created what they called "animats," simulated animals rather like avatars in an electronic game. By then having a population of animats "swim" through the acoustic footprint, with different animats taking different routes but all animats motivated by a

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● FINANCE & ECONOMY

State 'back in the game' with tax change

Janet Weiss, BP's Alaska region president, says company to evaluate opportunities, seek approval for additional long-term activity

By KRISTEN NELSON

Petroleum News

Passage of Gov. Sean Parnell's oil tax change puts Alaska "back in the game," BP Alaska Region President Janet Weiss said in comments emailed to Petroleum News April 18.

"As a package, this is an important step forward and will help us compete for more investment. This puts Alaska back in the game," Weiss said of passage by the Alaska Legislature of the committee substitute for Senate Bill 21, the governor's oil tax change.

Damian Bilbao, head of finance for BP in Alaska, used similar terminology in committee hearings on the legislation, telling legislators elimination of progressivity was a "game changer" putting Alaska back in the game of competing for investment.

"Now that we know the legislative outcome, we will evaluate our hopper of investment opportunities to understand the impact of the changes relative to our strategy, including BP's suite of global opportunities and our co-owners' support of the opportunities," Weiss said in the emailed comments.

Bilbao told legislators that as BP analyzes and ranks hundreds of projects the question is which are economic. He said there is an annual review of potential projects to see if circumstances have changed, including whether technology or efficiencies have changed. Fiscal policy impacts that decision, he said, and while projects are prioritized locally they have to compete for a fixed amount of worldwide investment.

JANET WEISS

Bilbao told legislators before passage of SB 21 that a fair number of Alaska projects were not competing because of the state's fiscal regime and the high cost of doing projects in Alaska.

"Alaska legislators understand that change cannot happen overnight," Weiss said, "but they are expecting us to move expeditiously and efficiently forward. That means our work over the next couple of years to advance the possible into the actual is critical."

Bilbao told legislators that the first thing that would happen following a fiscal change would be more drilling or finding more rigs to drill more, followed by more sizeable capital investments in things like new pads, which lead to more drilling and more oil.

He said more capital intensive changes would take a few years, and said prior to bill passage that while he couldn't say for certain about shorter-term changes such as more drilling without knowing the final bill, shorter-term activity could shift in the next one to two years.

Weiss said following passage of the bill that BP "will change our long-term plans accordingly, seeking appropriate sanctions for additional activity."

"Our evaluation will include natural gas given that an improved oil fiscal environment has been a prerequisite to advancing work on LNG," she said.

BP, ConocoPhillips, ExxonMobil and TransCanada have met benchmarks set out by Parnell for a liquefied natural gas project, most recently in mid-February when they provided details on the project, and said they had "completed the concept selection phase."

In a Feb. 15 letter to the governor detailing work completed the companies said they were "working toward the next decision points," but noted, as they had in an Oct. 1 letter, that "a competitive, predictable and durable oil and gas fiscal environment will be required for a project of this unprecedented scale, complexity and cost, to compete in global energy markets." ●

Contact Kristen Nelson at knelson@petroleumnews.com

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SOUND SOURCES

desire to move east to west through the Beaufort, it became possible to observe simulated animal movements and measure potential animal sound exposures. The simulation could be run with or without sound avoidance behavior built into the animat characteristics, Guerra explained.

Exposure data

With sound avoidance included, causing sound to deflect the whales' migration paths, 99 percent of the animats took action to avoid sound levels of 180 decibels or higher; 85 percent avoided sounds greater than 170 decibels and 60 percent avoided 160-decibel noise, Guerra said. And the model provided data about how much noise each animat encountered along its route through the sea, with the sound exposure for different animats at different times from different sound sources depending on the distance from shore of each animat's migration path.

Potential animal sound exposure histories derived from a simulator system like this demonstrate how sound exposures from multiples sound sources can be just as important as the type of single-source sound exposure typically assessed when regulating industrial activities, Guerra said. However, although the research group has discussed the future possibility of government agencies using this type of simulator system for regulatory decision making, presumably enabling assessments of the cumulative impacts of multiple, concurrent activities, Guerra stressed that the research program remains far from reaching a point where the simulator tool could be used for this purpose.

For example, in running the Beaufort Sea simulation the researchers made several simplifying assumptions about the various sound sources, Guerra said. The simulator model could incorporate much greater complexity. And, with scientific papers on the research in progress, the scientists have not yet finalized the modeling method, she said.

The research is a work in progress, a simple first step towards a potentially useful tool, as activity levels in the Arctic increase, Guerra said. ●

Contact Alan Bailey at abailey@petroleumnews.com

● GOVERNMENT

British Columbia faces carbon tax hike

By GARY PARK

For Petroleum News

British Columbia leads the only three of Canada's 10 provinces to have imposed a carbon tax and if the province changes government after its May 14 election that role will be strengthened.

Adrian Dix, leader of the socialist New Democratic Party that has entered a month-long election campaign with a seemingly insurmountable advantage in the polls, has pledged to expand the tax to cover vented oil and natural gas emissions.

Premier Christy Clark, whose Liberal party faces defeat for the first time in 12 years, has countered with a vow to freeze the tax for at least another five years.

The NDP, which has 48 percent support among decided voters in the latest polls compared with the Liberals 29 percent, has also declared it will block Enbridge's Northern Gateway pipeline if the project, which Prime Minister Stephen Harper views as a strategic imperative, is approved by the Canadian government.

'Economic suicide' warnings

Together, his two commitments are generating warnings of "economic suicide" from energy industry analysts.

Bill Gwozd, senior vice president of gas services at Ziff Energy, said a tax increase would amount to "throwing darts" at an industry suffering from weak commodity prices.

He predicted exploration and production companies would start moving their capital elsewhere, resulting in British Columbia "committing economic suicide."

Peter Tertzakian, chief energy economist at ARC Financial, said that adding more costs to a gas industry that is fighting for survival would be a bad move until producers can sell their production into LNG markets in Asia.

"Until there is some price recovery for natural gas from accessing global markets — which is five years away — the industry has almost no capacity to absorb another tax," he said.

"To burden a fuel that is actually helping to reduce carbon emissions across the continent doesn't make sense.

"Producers are looking to British Columbia to spend money developing LNG terminals and to send that kind of signal to them creates uncertainty," he said.

NDP plans to broaden tax

Dix said an NDP government would broaden the carbon tax, first introduced five years ago, in increments to charge C$10 per metric ton on production emissions in the first year, rising to C$20 in 2015 and C$30 in 2016.

He said the move would cover an additional 5 percent of carbon emissions in the province and generate an extra C$100 million in 2016 on top of the C$1.2 billion in taxes collected in 2012.

NDP energy spokesman John Horgan said he has told the industry his party's aim is to drive down emissions, not increase costs for producers who are struggling with both low gas prices and the added costs of accessing distant markets in North America.

"Our objective here is not a revenue grab," he said.

Clark argued it was now time for other North American jurisdictions to catch up to British Columbia, a view that has been endorsed by Canada 2020.

The new think tank said it is time for a national debate on the issue, despite the outright rejection of a carbon tax by the Harper government.

Canada 2020 leaders, former Quebec premier Jean Charest and Eric Newell, former chief executive officer of the Syncrude Canada oil sands consortium, suggest that unless Canada shows it is serious about tackling greenhouse gas emissions it cannot expect support from the United States for projects such as the Keystone XL pipeline.

Seven years of decline

But the prospect of an added squeeze on British Columbia's gas sector comes after seven years of steady decline, with the B.C. Oil and Gas Commission reporting that 131 wells were drilled in the first quarter of 2013, compared with 1,435 wells for all of 2006.

The natural gas sector is the largest single source of greenhouse gas emissions in British Columbia, which produces about 1 trillion cubic feet a year, second among Canada's three producing provinces behind Alberta.

The existing carbon tax covers combustion and flaring. Venting occurs at either the well site or processing plant when CO_2 is stripped out and released as well as when methane is released from pipelines.

The Alberta-based Pembina Institute estimated that imposing a tax on venting will increase the tax coverage to 75 percent of all British Columbia emissions from 70 percent.

On the national front, Greg Stringham, vice president of markets and fiscal policy with the Canadian Association of Petroleum Producers, told an industry meeting that new oil sands mining and in-situ projects are making headway in dealing with GHGs.

He said emissions per barrel of production have been lowered by 26 percent over the past 20 years, applying what he ranked as best-in-class technologies. ●

Contact Gary Park through publisher@petroleumnews.com

● EXPLORATION & PRODUCTION

Gathering data on the Nenana basin

DGGS-led team reports on the status of its field work, sampling and analysis, assessing the basin's oil and gas potential

By ALAN BAILEY
Petroleum News

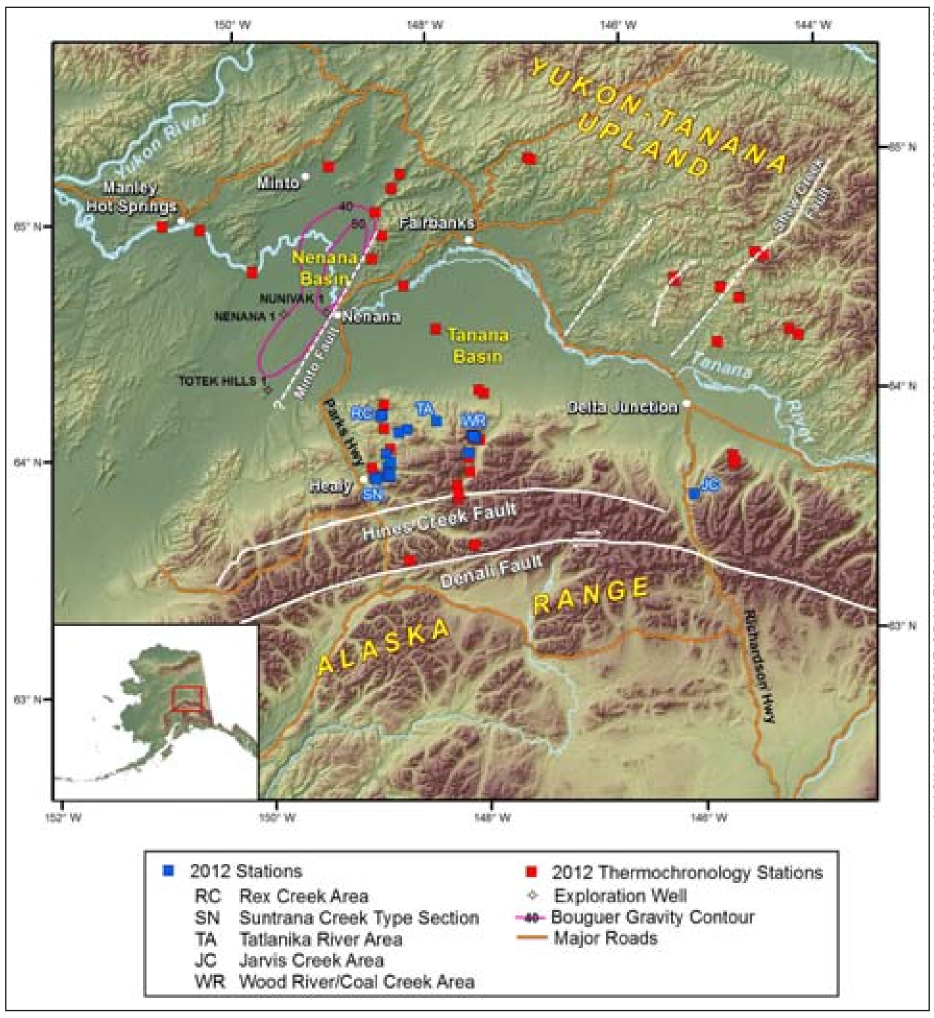
Alaska's Division of Geological and Geophysical Surveys, or DGGS, has published a status report on research it is conducting into the oil and gas potential of the Nenana basin, a large sediment-containing trough in Alaska's Interior, about 50 miles southwest of Fairbanks. Geologists have long viewed the basin as likely to contain natural gas. And, with the basin being close to the transportation corridor between the cities of Anchorage and Fairbanks, the possibility of a significant gas find in the basin offers the tantalizing possibility of a new source of gas for space heating or power generation in the Alaska Railbelt.

Doyon exploration

Doyon Ltd., the Native regional corporation for the Alaska Interior, has been spearheading efforts to explore the basin — in 2009 the corporation drilled the Nunivak No. 1 well in the basin near the village of Nenana and the corporation plans another well nearby this summer. Doyon has said that, while the Nunivak well did not encounter commercial quantities of gas, the well did provide intriguing evidence for the hydrocarbon potential of the basin. And the corporation says that its exploration efforts have uncovered indications that the basin may hold oil as well as gas.

With very little rock exposed at the surface within the area of the basin, geologic assessments of the basin depend on examinations of rock exposures in the hills around the basin margin, coupled with insights from gravity and seismic data gathered in the basin. Some limited subsurface data are also available from the Nunivak well and two earlier wells, drilled several years ago on the basin's flanks.

Some results from the Doyon exploration have indicated that the basin may be much deeper than previously thought, with the possibility that potential source rocks have been buried to depths where temperatures would drive oil or gas formation. Conventional thinking about potential natural gas formation in the basin has tended to assume that, rather than forming from the application of heat, gas would be generated from the action of bacteria on organic material in coal seams.



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

Geologists think that the Nenana basin southwest of Fairbanks is prospective for natural gas and could perhaps also hold oil. A team of scientists led by Alaska's Division of Geological and Geophysical Surveys is investigating the hydrocarbon potential of the basin.

Reconnaissance fieldwork

The DGGS research involves a team of scientists from DGGS, Alaska's Division of Oil and Gas, the U.S. Geological Survey and the University of Alaska Fairbanks. In 2012, the year when the Nenana basin research started, the team carried out reconnaissance fieldwork, verifying, measuring and sampling the rock sequences exposed on the southeast side of the basin and on the south side of the adjoining Tanana basin on the north side of the Alaska Range.

"The goal of this work was to improve our understanding of the geologic development of the Nenana basin and to collect a suite of samples to better evaluate hydrocarbon potential," the report says.

The DGGS-led team visited well-exposed sections of the basin fill, at the edge of the basin near and to the east of Healy, the site of Alaska's only commercial coal mining operation. The team made detailed measurements of the sequence of exposed rock strata and took rock samples, assessing some rock units for their potential as hydrocarbon sources and other units for their possible effectiveness as hydrocarbon reservoirs.

Rivers and lakes

Geologists think that the Nenana basin, formed as a consequence of the movement of the Earth's crust around some major geologic faults, is probably filled with relatively young sediments, primarily Tertiary in age and laid down from systems of rivers and lakes, and with periods of luxuriant vegetation growth giving rise to substantial coal seams.

Coal seams in the basin could source gas, and perhaps oil. However, the DGGS-led team also sees possible comparisons between lake-deposited sediments in the Nenana basin and organic-rich lake sediments elsewhere in the world that can source oil. The team has taken samples from a rock formation of this type exposed near Healy for laboratory analysis, the DGGS report says.

And field observations appeared to confirm that many of the rocks in the basin were laid down as sediments deposited from rivers. However, geologic features that the team encountered during its fieldwork included a fossil forest, buried and preserved in volcanic ash, the DGGS report says.

Samples for timing

The field team also collected rock samples from the older rocks which form the basement to the basin and which are

see NENANA BASIN page 11


BROOKS RANGE PETROLEUM CORP.

Completion of Mustang Road construction

● EXPLORATION & PRODUCTION

JV finishes North Slope road

Partnership between AIDEA and AVCG/Ramshorn completes five-mile road and 19-acre pad at Southern Miluveach unit

By ERIC LIDJI
For Petroleum News

A public-private joint venture has completed its first North Slope infrastructure project.

Mustang Road LLC recently completed a five-mile gravel road and an associated 19-acre gravel pad to support development activities at the Mustang field in the Southern Miluveach unit, according to joint venture operator Brooks Range Petroleum Corp.

The Alaska Industrial Development and Export Authority owns an 80 percent interest in the joint venture and the small independents AVCG LLC and Ramshorn Investments Inc. own the remaining 20 percent. The independents are partners on the Mustang leases.

Through the deal, AIDEA loaned the partnership $20 million toward the $25 million cost of the road, pad and other associated infrastructure projects connected to development.

"We are pleased that after only two years from drilling our discovery well at Mustang, we have completed this first phase of development," BRPC's Chief Operating Officer Bart Armfield said in a statement, adding, "Our primary contractor, Alaska Interstate Construction, and all subcontractors did an outstanding job of bringing this project in on time while maintaining an excellent safety and environmental protection record."

The road is located just southwest of the Kuparuk River unit. The pad will eventually become the site for drilling, processing facilities, an operations center and a camp.

AIDEA Deputy Director of Project Development and Asset Management James Hemsath called the project "an important step in a new era of North Slope developers and producers." The partnership is part of a larger AIDEA strategy to help finance aspects of oil and gas developments that are economic, but somehow ill suited for private financing.

AIDEA also intends to help finance production facilities at Mustang, a move it can take because the Alaska Legislature recently gave the public corporation additional authority.

Brooks Range Petroleum said it expects to start building facilities this year, start drilling at Mustang in 2014 and bring the field into production toward the end of the year. The company estimates peak production from the field to be some 14,000 barrels per day. ●

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FINANCE & ECONOMY

Shell, Noble discussing Arctic contracts

Hunt also commented that ConocoPhillips has exercised a termination right for a contract to use a jack-up rig that Noble has under construction in Singapore, following ConocoPhillips' decision to defer its Chukchi Sea drilling, originally planned for 2014.

Drilling company Noble Corp. is in discussions over extending its contracts with Shell for Shell's Alaska Arctic offshore exploration drilling program, Roger Hunt, Noble senior vice president, marketing and contracts, said during Noble's earnings conference call on April 18. Noble's drillship Noble Discoverer drilled a top hole in Shell's Chukchi Sea Burger prospect last year, while the drilling company also operated the Shell-owned Kulluk floating drilling platform in the Beaufort Sea.

The current contract for the Noble Discoverer continues through to February 2014, but discussions with Shell revolve around a contract extension that goes well beyond that date, Hunt said. Shell has cancelled its plans for drilling in the Alaska Arctic in 2013.

Both the Noble Discoverer and the Kulluk have been transported to Asian shipyards for repair following propulsion and other problems with the Noble Discoverer and the grounding of the Kulluk in the Gulf of Alaska.

"We have the drillship Discoverer in Korea. We're doing a body of work," Hunt said, adding that Shell has its own project team dealing with repairs to the Kulluk. Noble is discussing with Shell extending the operating contract for the Kulluk, once the Kulluk is back in service, he said.

Hunt also commented that ConocoPhillips has exercised a termination right for a contract to use a jack-up rig that Noble has under construction in Singapore, following ConocoPhillips' decision to defer its Chukchi Sea drilling, originally planned for 2014. Under the contract termination agreement Noble will receive a settlement of $18 million plus any expenses related to planned rig winterization, Hunt said. Noble anticipates being able to secure an alternative customer for the rig when the rig is delivered from Singapore in the fourth quarter of 2013, he said.

—ALAN BAILEY

continued from page 10

NENANA BASIN

exposed in the hills on the north and south sides of the basin, and in the Yukon-Tanana uplands to the east. These rocks, igneous and metamorphic in nature, contain minerals that the team hopes will provide insights into the thermal history of the basin floor, thus providing evidence for the timing of Nenana basin formation.

DGGS says that it anticipates publishing detailed results from its interpretations of hydrocarbon reservoir and source rock quality in the basin by the end of 2013. In due course the team will also publish the results from the laboratory analyses of rock samples collected in 2012. In 2013 the research team may conduct an additional evaluation of rock cuttings from the Nunivak well, including a supplementary analysis of data that can be gleaned from those cuttings. The team is also considering some further field studies in the northern Alaska Range, the DGGS report says. ●

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NATURAL GAS

Market awaits impact of NA LNG exports

By BILL WHITE

Researcher/writer for the Office of the Federal Coordinator

Slumbering giants get moving

Japan and China weren't slow on their feet for long.

Starting in the summer of 2012, Japanese buyers signed these tentative deals:

1 2 SERIES

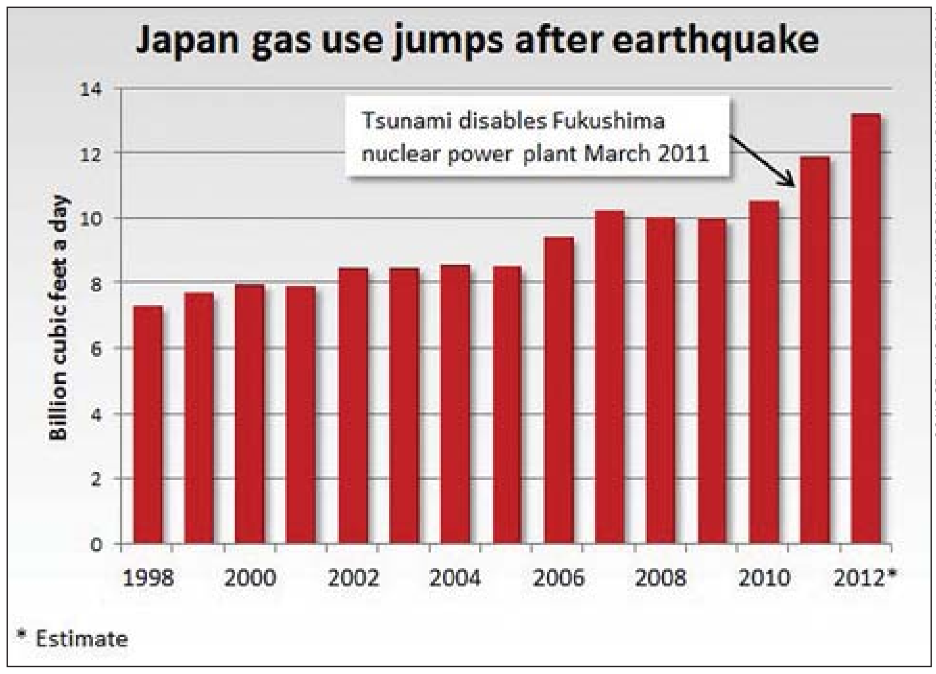
•Mitsui & Co. and Mitsubishi Corp. signed to take about 1.1 bcf a day from the proposed Cameron LNG export plant at Hackberry, La.

•Tokyo Electric Power then signed to take about 100 million cubic feet a day of the Mitsui and Mitsubishi shares. TEPCO is negotiating for an additional 160 million cubic feet a day from other suppliers, the company's managing executive officer said in February 2013.

•Osaka Gas and Chubu Electric Power have deals for 600 million cubic feet a day from a proposed export plant in Freeport, Texas.

•Tokyo Gas and Sumitomo Corp have signed for about 310 million cubic feet a day from a proposed Maryland export project.

These deals are preliminary because the proposed LNG plants involved still need regulatory approval ... and corporate go-ahead for the billions in construction.



SOURCE: U.S. ENERGY INFORMATION ADMINISTRATION

Chinese companies have been busy investing in shale gas plays or possible LNG projects in North America, Australia and Africa. Some Japanese companies have made similar investments.

BILL WHITE

"Japan expects LNG exports from the U.S. will be a game changer for the Japanese LNG market," Shinichi Kihara, head of global affairs at Japan's trade ministry, said at a Houston energy conference in March 2013.

"Price really matters to Japan," he said. "There are many options, but we think the principle is to have a formula that represents the demand and supply situation in Asia."

Kihara echoed sentiments first expressed publicly in September 2012 by Japanese, Korean and Taiwanese leaders and utility executives at an LNG conference called by the Japanese government.

"Japan's LNG prices have deviated significantly from international norms," said Tsuyoshi Okamoto, president of Tokyo Gas. "If this discrepancy continues, it will result in curbed natural gas consumption and conversion to other energy sources."

Whipsawed in Japan

Japan has been double-whammied since the March 2011 earthquake and tsunami sparked an on-going safety shutdown of most of the nation's nuclear power plants.

LNG imports are up — 25 percent.

So are LNG prices — 50 percent.

In the past two years Japan endured its first trade deficits since the early 1980s.

"As a result of larger LNG import volume and surging prices, LNG import value has increased. This, along with decreasing exports of goods and services owing to the global economic recession, constitutes a major factor of Japan's trade deficits and the downward pressure on Japanese economy," the Institute of Energy Economists Japan said in a January 2013 report.

The IEEJ estimated Japanese utilities could save billions by importing LNG at North American prices.

More movement toward Henry Hub pricing

Japanese companies aren't the only businesses knocking on doors of proposed U.S. LNG plants to talk terms.

In January 2013, Shell preliminarily agreed to take up to 500 million cubic feet a day as LNG from a proposed plant in Savannah, Ga., for marketing to Shell customers worldwide.

In February 2013, BP tentatively agreed to take up to 590 million cubic feet from a proposed LNG export project in Freeport, Texas.

Separately, in November 2012, BP's Singapore arm signed a preliminary long-term deal to sell 67 million cubic feet a day to Kansai Electric at prices linked to the Henry Hub.

Henry Hub prices reportedly have started seeping into contracts for LNG sourced elsewhere in the world.

BG Group recently committed Australian LNG to a China energy company at a price 25 percent linked to Henry

see EXPORT IMPACT page 13

continued from page 12

EXPORT IMPACT

Hub and 75 percent linked to oil prices. Chevron also reportedly committed Australian LNG to two Japanese utilities that included a small Henry Hub linkage.

In addition, BP signed a deal with Japan's Chubu Electric to supply about 1.1 bcf a day of LNG for 16 years at prices partly indexed to the British gas hub called National Balancing Point, according to trade publication ICIS Heren in December 2012.

And Qatar recently weakened the oil-link formula slightly in contracts with three Japanese utilities, ICIS Heren said.

The rise of oil-linked prices

Linking Asia LNG prices to oil dates to the 1970s, when oil-price shocks sparked long lines at gas stations, runaway inflation and swooning economies in developed countries.

At the time, imported oil by far was the fuel of choice for resource-poor Japan. To break its dependence on oil, Japan began building nuclear power plants and importing LNG, then a new product on the global trade scene.

But how to price LNG? Sellers needed long-term contracts at high enough prices to support the massive cost of building LNG plants. Oil would be the fuel displaced, so Japan agreed to link LNG prices to the oil-imports cost, a blend of prices known now as the Japan Crude Cocktail.

Because a standard unit of natural gas — 1 million Btu — packs about 17 percent of the energy found in a barrel of oil, this percentage — called the "slope" — is a kind of starting point for the oil-linked formula during contract negotiations. It might be much smaller for contracts negotiated in a buyer's market. A typical contract today might set this slope at 14 to 15 percent of the oil price. A contract also could install a ceiling on price to protect buyers, and a floor to protect sellers.

When South Korea started LNG imports in 1986 and Taiwan in 1990, they were shopping the same suppliers selling to Japan, and the oil-linked price became standard in their contracts, too.

Until 2012. That's when buyers' pushback got traction.

"With the paradigm shift due to full-fledged production of shale gas (in North America), oil-linked indexing is starting to be less reasonable," said Yukio Edano, Japan's trade minister, at the September conference in Tokyo. "If new suppliers from North America, Russia and Africa enter Asian markets in a few years, it will no longer be reasonable."

In November, a Japan trade ministry official put it this way: "From all the aspects, U.S. LNG is a very, very shining treasure ... for us."

Sellers recoil

Lest one conclude that global LNG sellers are hunkered behind the ramparts while all this revolutionary Henry Hub talk is going on, think again.

"I can tell you it takes a large capital commitment, and most companies in the world aren't going to make that commitment without having pricing that gives them a fair return, and that pricing is going to need to be something close to oil parity, or the projects won't get built," John Watson, Chevron's chief executive, said in February 2013. Chevron is a partner in two Australia LNG projects and is proposing a major export project for Canada's West Coast.

In March, Watson hit it again: "Given the large capital requirements, long construction lead time and obstacles to development, there are only a handful of companies that have the financial and operating capability to take on LNG projects. And they will require a fair return on their investments to do so. This will necessitate long-term purchase contracts with robust underlying LNG prices."

An executive with Apache Corp., which is partners with Chevron in Australia and Canada, said Cheniere's deals for LNG from its Sabine Pass, La., plant under construction have created "unrealistic expectations" among LNG buyers.

The CEO of Santos, which is developing a different Australian LNG export project, said in November that Japanese buyers need to know the supplies they buy will arrive when wanted. "They like to know that the molecules are there in the ground and they will, through prudent operators, be delivered into Tokyo Bay," said David Knox. "I suspect there will be a mixture of the way contracts are linked but I think ... fundamentally [oil price linking] will remain and the reason it will remain is [because] of security of supply being so important."

A trade group sounded off, too.

"Oil parity prices are fair enough in order to establish a win-win scenario for both suppliers and consumers. Otherwise the producing country's huge investment for capital intensive gas export projects would not be economically viable," said Leonid Bokhanovskiy, secretary general of the Gas Exporting Countries Forum. "The loss in short-run may hit only producers but in long-term project financiers will lose motivation for investment. The lack of investment will lead to production declines. It is to benefit of consumer and supplier to buy and sell gas at the fair price."

Some analysts see a future for oil-linked pricing, too. "The Asian LNG price will remain predominantly linked to oil for the next 20 years or so," said Shahriar Fesharaski of FACTS Global Energy, at a Singapore conference in January 2013. "The incremental volumes over the next few years are coming from Australia and they are linked to oil, and in 2016-2017 we could see some U.S. projects coming online, so Henry Hub linkage will increase a bit, but the incremental volumes will still be linked to oil," Fesharaki said.

A Sanford Bernstein analyst said in October 2012, "There is no such thing as a global gas market, and we think it is unlikely there ever will be in the next 20 years." The analyst, Neil Beveridge, added, "The expansion of gas projects in Australia would not have been possible without the direct linkage between oil and gas prices."

How much U.S. LNG?

Nearly everyone notes that a rise in North American gas prices or a dramatic fall in world oil prices would let the air out of plans to export U.S. gas.

The wide divide between U.S. and Asian gas prices is a recent phenomenon, opening up only starting around 2008 when substantial shale gas started hitting U.S. markets and, separately, world oil prices skyrocketed.

Before that, any price premium LNG garnered in Asia was too small to justify shipping North American gas there. In fact, from 2003 through 2005, Henry Hub prices were higher than Japan LNG prices.

"It is important to note that Henry Hub pricing doesn't necessarily mean cheap pricing," Andrew Walker, vice president for global LNG at U.K.-based BG Group, said at a London gas conference in October.

"It is uncertain whether U.S. LNG can actually be imported at a low price," the IEEJ study said.

Walker and others think the global gas market has room for only so much U.S. LNG.

see **EXPORT IMPACT** *page 14*

NATURAL GAS

NordAq seeks Kenai road easement

Anchorage-based independent NordAq Energy Inc. is applying for a private easement to support its natural gas exploration and development efforts on Alaska's Kenai Peninsula.

The state Department of Natural Resources is taking public comment on the application through May 20.

The proposed road easement would be 80 feet wide and 9,504 feet or 1.8 miles long.

A map indicates the all-season gravel road would start near the Captain Cook State Recreation Area northeast of the Nikiski community.

The road would run south to an appraisal well pad. Farther south is the site of the Shadura No. 1 wildcat well, which NordAq drilled in early 2011. The company constructed an ice road to reach the site.

NordAq is pursuing a gas development project on a proposed drilling and processing pad more than a mile east of the Shadura No. 1 well. NordAq has said it might drill up to six production wells.

The project is inside the Kenai National Wildlife Refuge.

In December, the U.S. Fish and Wildlife Service released a draft environmental impact statement. The EIS looked at various alternatives to permit road access to the Shadura development site.

The federal government owns the land surface in the project area, while Cook Inlet Region Inc. owns the subsurface oil and gas estate. CIRI has entered into a lease with NordAq to develop the gas resource.

Federal regulations require the Fish and Wildlife Service to grant "adequate and feasible" access to the owners of inholdings for economic purposes.

An April 19 DNR notice said NordAq, in its original application for the gravel road easement, also included requests to authorize gas gathering lines and communications cables to be co-located with the access road.

Subsequently, NordAq amended its request to include authorization of only the access road at this time, the DNR notice said.

The company indicated it would submit a separate application "at a future date" for the remainder of the infrastructure, the notice said.

—WESLEY LOY

ENVIRONMENT & SAFETY

More cameras to watch for inlet ice

The Cook Inlet Regional Citizens Advisory Council is adding more cameras to monitor ice in the inlet.

In its 2012 annual report, the organization says its Ice Forecasting Network of cameras and overflights delivers vital information to the National Oceanic and Atmospheric Administration ice forecaster to aid Cook Inlet mariners.

"With a boost from our Kenai delegation and the 2012 Alaska Legislature, Cook Inlet RCAC secured capital funding for two additional cameras to cover more area from Hilcorp Alaska's Granite Point and Cook Inlet Energy's Osprey offshore platforms," the annual report says. "These join the six active cameras already in place at the XTO A platform, OSK (Offshore Systems Kenai) dock, ASRC Energy Services, Port of Anchorage, and Port MacKenzie."

Winter ice is a serious hazard to oil tankers and other vessels in Cook Inlet. Drifting ice floes have been known to damage vessels, or cause them to break away from their moorings. The U.S. Coast Guard imposes special rules for vessel operators during periods of extreme ice.

The Cook Inlet RCAC is a Kenai-based, congressionally mandated organization formed after the 1989 Exxon Valdez oil spill in Prince William Sound. The council says its mission is promoting safe marine transportation and oil facility operations in Cook Inlet.

—WESLEY LOY

GOVERNMENT

Legislature confirms Foerster, Rokeberg

Cathy Foerster and Norm Rokeberg were among Gov. Sean Parnell's appointments approved by the Alaska Legislature April 8.

Foerster, who holds the petroleum engineer seat on the Alaska Oil and Gas Conservation Commission, and is serving as the commission's chair, was appointed 2005 and reappointed in 2007. Her current reappointment was effective March 1; the term expires March 1, 2019.

Rokeberg was confirmed to the Regulatory Commission of Alaska. He was named to the seat March 1, replacing Kate Giard, who resigned as a commissioner Jan. 4. Rokeberg's term expires March 1, 2019.

—PETROLEUM NEWS

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EXPORT IMPACT

Still, optimism reigns among Asian buyers.

"Thanks to shale gas, we now have a realistic chance of solving our energy problems," mused Hidetaka Matsuzaka, a senior Osaka Gas executive, in November. "If we can purchase LNG at U.S. market prices and diversify our overall pricing structure, this will be a significant achievement indeed." ●

Part 1 of this story ran in the April 21 issue of Petroleum News.

Editor's note: This is a reprint from the Office of the Federal Coordinator, Alaska Natural Gas Transportation Projects, online at www.arcticgas.gov/market-awaits-impact-north-america-lng-exports.

● FINANCE & ECONOMY

Furie suit contesting fine stays alive

Alaska federal judge declines to dismiss company's challenge of $15 million Jones Act penalty for alleged illegal rig transport

By WESLEY LOY

For Petroleum News

Furie Operating Alaska LLC has won a round in its fight to fend off a $15 million Jones Act penalty.

A federal judge has denied a government motion to throw out a lawsuit Furie filed against U.S. Customs and Border Protection, which imposed the fine. CBP is an agency within the Department of Homeland Security.

Furie sued in August 2012 in an effort to nullify the fine, which the company has called arbitrary and excessive.

The fine stems from Furie's use of a foreign-flagged ship to haul a jack-up drilling rig part of the way from Texas to Alaska in 2011. CBP officials said the transport constituted a violation of the Jones Act, a shipping law.

Furie tried to appeal the fine to the government, but these efforts were unsuccessful and the company finally sued in U.S. District Court in Anchorage.

Lawyers for the government moved for dismissal of the suit, arguing the court lacked jurisdiction because the penalty assessment was not a "final agency action."

Federal Judge John W. Sedwick, however, denied the motion in a 12-page order and opinion issued April 15.

It means, apparently, that if the government really wants to collect the $15 million from Furie, it will have to prevail in the case Furie filed.

The voyage

Furie, headquartered in League City, Texas, is using the Spartan 151 jack-up rig to explore for natural gas in Cook Inlet.

In 2011, the company used a foreign-flag, heavy-haul ship to carry the rig from Texas to Vancouver, British Columbia. Furie has said no suitable U.S. ships were available to safety carry the Spartan 151 around South America, the rig being too big to go through the Panama Canal.

From Vancouver, Furie used U.S. tugs to tow the rig the rest of the way to Alaska.

STEVE SUTHERLIN

The Spartan 151 jack-up rig.

CBP officials in October 2011 imposed a $15 million fine, saying use of the foreign-flag transport ship for part of the journey violated the Jones Act. The act prohibits shipping merchandise between U.S. points, either directly or via a foreign port, unless the transport vessel is U.S.-built and documented and owned by U.S. citizens.

At the time it moved the rig, Furie was trying to gain a Jones Act waiver to use the foreign transport ship.

Escopeta Oil Co., which Furie acquired in June 2011, had received such a waiver for a different rig and ship in 2006 from then-Homeland Security Secretary Michael Chertoff. The waiver was based on national security considerations, including Southcentral Alaska's need for new gas supplies and the presence of Joint Base Elmendorf-Richardson in Anchorage.

Ultimately, Homeland Security Secretary Janet Napolitano would deny Furie a new waiver. But the company went ahead and completed the rig move to Alaska.

Furie said Napolitano and other officials indicated they wouldn't seize the rig, and might mitigate any Jones Act penalty.

CBP officials determined the value of the rig was $15 million, and so that's the penalty they imposed.

Interfering with business

Furie petitioned twice for mitigation, but CBP denied these. The agency also denied requests for reconsideration.

CBP billed Furie three times for the $15 million, threatening to send the matter to collections.

Furie never paid, and filed its lawsuit.

In its motion to dismiss, the government argued Furie was under no obligation to pay, that payment would be necessary only if the government sued and won a judgment for the money.

Thus, the government argued, Furie's suit was premature and should be thrown out.

Furie argued the Jones Act penalty, though uncollected, was working a hardship on the company. The looming fine, and the refusal of officials to mitigate it, "has made it difficult for Furie to secure investors in its resource exploration and development venture," Furie's president, Damon Kade, said in a Dec. 14 declaration.

Judge Sedwick ruled the argument that the penalty was not a final agency action until the government sued to enforce it was "without merit."

He noted that federal officials had denied Furie's petitions and requests for reconsideration, and had sent the company three bills, indicating CBP had reached "the culmination of the agency's decision-making process."

In the government's view, Sedwick observed, Furie would have to wait until a collection action was filed before it could raise any judicial challenge to CBP's decision. Furie couldn't predict when such an action would be filed.

"In the meantime, while it waits it is subject to a $15 million penalty and possible sanctions for non-payment, and such a substantial liability certainly interferes with its ability to conduct business," Sedwick wrote. ●

Contact Wesley Loy at wloy@petroleumnews.com

● NATURAL GAS

So far, so good for CINGSA gas storage

Facility averted potential Southcentral Alaska gas delivery shortfalls during the past winter; utilities seek new supply contracts

By ALAN BAILEY
Petroleum News

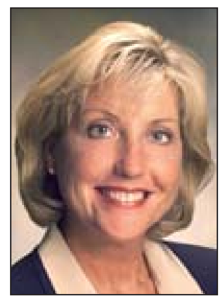
The new natural gas storage facility operated by Cook Inlet Natural Gas Storage Alaska, or CINGSA, near the city of Kenai on Alaska's Kenai Peninsula played an essential role in filling what would otherwise have been shortfalls in Southcentral Alaska's utility gas deliveries during the past winter, Colleen Starring, president of CINGSA, told the Regulatory Commission of Alaska, or RCA, on April 24. Starring expressed relief that the storage facility had fulfilled its role of ensuring adequate utility gas supplies during cold winter weather.

"We've made it through the winter of 2012-2013," Starring said.

CINGSA's initial customers were Enstar Natural Gas Co., Chugach Electric Association and Municipal Light and Power, with Homer Electric Association signed up to use the facility, starting in November 2013. Starring said that in March ConocoPhillips signed up as a customer for an interruptible storage service.

Market flux

Starring, who is also president of Enstar, the main Southcentral gas utility, commented that the Cook Inlet gas market is in a state of flux, with Hilcorp Alaska, the company that has taken over Cook Inlet gas fields previously owned by Chevron and Marathon, being a significant player in that market, and with the Southcentral utilities now being involved in new gas supply contract negotiations.


COLLEEN STARRING

"We have some good news on the horizon," Starring said. "We've been working very closely with Hilcorp."

In early February Hilcorp completed its purchase of Marathon's Cook Inlet gas fields and shortly afterwards Hilcorp's president, Greg Lalicker, told the Alaska Legislature that his company was in the process of figuring out new gas supply arrangements with Southcentral utilities.

Game changers

"There have been a number of game changers in just the last month," Starring told the RCA commissioners. "We can't say enough about working with the folks over at Hilcorp and some of the early indications of what they can do."

Enstar officials later told Petroleum News that the utility is in a holding pattern over future Southcentral gas supply decisions while new supply contracts with Cook Inlet producers are being negotiated. Southcentral utilities have been investigating the possibility of importing gas from out of state, to fill looming shortfalls in Cook Inlet gas supplies as gas production from aging local gas fields declines.

Starring told the commissioners that in the future Enstar will have to manage for itself the extreme swings in Southcentral utility gas demand between summer and winter, rather than depend on the gas producers to deal with those swings. And next winter the utility expects to have to pull very hard on the CINGSA facility for sustained periods of time, she said.

On schedule

Starring said that the CINGSA facility had gone into operation, on schedule, on April 1, 2012, at which point the facility started accepting deliveries of gas for storage. After some initial difficulties with some of the wells in the facility, operations settled down. And the performance of all of the wells has steadily improved with use, to the point where the total capability of the facility is somewhat unclear. CINGSA had been deliberately conservative in its initial performance expectations, in the absence of a track record for the wells, Starring explained.

CINGSA customers waited expectantly around Nov. 9, the date at which stored gas was first withdrawn from the facility, as winter cold started to push up Southcentral gas demand. The gas did indeed flow from the facility, as planned, with subsequent storage reservoir pressures confirming that gas was being contained within the reservoir as expected.

"It's a good reservoir," Starring said, adding that severely cold weather in December had challenged utility gas supplies, making the availability of stored gas from CINGSA essential.

"But for CINGSA we might have had a very different outcome this winter," Starring said.

December withdrawals

Starring said that during December, with gas demand across all Southcentral utilities peaking at 312 million to 313 million cubic feet per day, CINGSA had to deliver anywhere from 18 million cubic feet per day to nearly 70 million cubic feet per day from storage, to ensure adequate gas continued to flow through the gas distribution system. Enstar itself was already obtaining about 240 million cubic feet per day direct from Cook Inlet gas producers, volumes that encompassed all possible gas from the utility's contracted supplies and as much gas as possible from a daily gas supply bidding system that the utility operates.

Somewhat warmer weather in January saw for the most part a significant drop in gas withdrawals from CINGSA, with even the occasional opportunity to inject excess gas back into the storage reservoir. It proved possible to switch the facility from gas withdrawal to gas injection in less than an hour, Starring said.

"Our philosophy at Enstar was whenever we could purchase gas we were going to grab it and put it in that facility," Starring said.

Financial success

As well as meeting all expectation for performance as a gas storage facility, the CINGSA project has proved successful from a financial perspective. An original cost estimate of around $180 million for the facility had dropped to a little over $160 million by the time facility construction was nearing completion in February 2012, Starring commented. And the final cost numbers look to be coming in close to that lower figure, she said. CINGSA anticipates reconciling final cost figures in April 2014, in preparation for the filing of a revised rate for facility use, based on actual cost data, Starring said.

Expansion possibility

CINGSA's storage capacity could be expanded at some point in the future, an exercise that might take 30 to 36 months to complete and that might cost somewhere between $25 million and $80 million, Starring said. But any expansion decision would depend on the outcome of new gas supply contract negotiations and the future gas market situation, she said. In the event of a facility expansion, CINGSA would hold an "open season," to provide potential customers with an opportunity to sign up for service, she said.

Starring characterized the CINGSA facility as a prime example of a utility success story and thanked the RCA commissioners and the leadership of the state Legislature for their decision making, to facilitate the fast and successful development of the storage facility. The Alaska Department of Natural Resources had also worked closely with CINGSA, and the facility's customers had set aside some of their individual interests, to ensure the facility's success for the benefit of all, Starring said. ●

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● FINANCE & ECONOMY

SB 21 could surpass ACES revenues

If production expanded — with new fields, more drill rigs, more pads at legacy fields — state could be ahead by FY '16 at $100 oil

By KRISTEN NELSON
Petroleum News

A big dispute in the battle over passage of Gov. Sean Parnell's oil tax change, Senate Bill 21, was how much the drop in oil taxes — particularly the elimination of progressivity — would cost the state in oil tax revenue.

The fiscal note provided by the Alaska Department of Revenue for the bill as passed by the Legislature provides estimates, although those estimates are based on production levels currently forecast by the department.

At current production forecasts, the state loses revenue under SB 21 into the foreseeable future, starting with a drop of $275 million in fiscal year 2014 at $100 oil, peaking at $475 million in FY 2017, and flattening out at $450 million in FY 2019.

But Revenue also laid out scenarios showing what would happen under SB 21 with additional production.

One new field

In scenario A, additional production comes from a 50 million barrel field developed by a new entrant. This would be a field outside an existing unit and would be subject to the 30 percent gross revenue exclusion, with first oil in 2017 and peak production of 10,000 barrels per day in 2019. Total development cost for the new field would be $500 million.

At $100 oil, state revenue losses are the same in FY 2014 through FY 2018, but the loss in FY 2019 drops from $450 million less than ACES to $425 million less than ACES as production from this hypothetical new field comes online.

Four rigs in legacy fields

In scenario B, Revenue projects the addition of four new rigs in legacy fields from 2014-19, each rig drilling four new production wells per year, each well producing 1,000 bpd beginning in 2014, with maximum production of 60,000 bpd for a total of 140 million barrels. Development costs for each well are estimated at $20 million; none of the oil in this scenario would qualify for the GRE under the provisions of SB 21.

At $100 oil, losses drop from $275 million to $200 million in FY 2014, and become positive at $25 million in FY 2015, rising to $75 million in FY 2016. There is no difference in FY 2017, but the state is ahead $225 million in FY 2018 and $50 million in FY 2018.

Rigs, new well pad

Scenario C includes the four additional rigs in legacy fields, plus the new 10,000 bpd new field and also includes a new well pad within an existing major North Slope unit producing 125 million barrels of new production over eight years starting in 2014 at a total development cost of $5 billion. Oil from wells at the new pad does not qualify for the GRE.

The combined scenarios, at $100 oil, brings production revenue under SB 21 level with ACES in FY 2015 and increases state revenues from FY 2016 through FY 2019 by $200 million, $350 million, $1,100 million and $925 million.

A fiscal note from the Department of Natural Resources using the scenarios developed by the Department of Revenue show increased revenues from royalties

The combined scenarios, at $100 oil, brings production revenue under SB 21 level with ACES in FY 2015 and increases state revenues from FY 2016 through FY 2019 by $200 million, $350 million, $1,100 million and $925 million.

under the combined scenarios of $91 million at $100 oil in FY 2014, rising to $435 million in FY 2019. Because SB 21 does not impact royalties, there is no change under currently forecast production volumes.

Mustang on books

Mustang, the Brooks Range Petroleum Corp. North Slope field near the Kuparuk unit, will be the first new oil to come online under the new fiscal system, but that field is already included in the Department of Revenue's projections of crude oil production, shown in the spring forecast as coming online after 2016.

Point Thomson is also included in Revenue's forecast, with production beginning in 2016.

Under existing projections, not including the scenarios, new oil is expected to contribute 3.1 percent of North Slope production this year, 10 percent in 2014 and steadily rising to 27.1 percent in 2022.

The decline rate of currently producing fields is shown at 9.9 percent this year, gradually dropping to 6.8 percent in 2022 in the spring forecast.

With new oil included in the forecast, the production decline rate drops to 7 percent this year and to 2.2 percent in 2014, rising to 7.5 percent in 2022.

Spring forecast down

The spring forecast is down from fall, at 548,700 barrels per day, compared to 563,200 bpd in the fall forecast. All of the difference comes from the North Slope, with Cook Inlet production for 2013 constant between the forecasts at 10,400 bpd.

The forecast also drops from 2014 and 2015, is the same for 2016 and rises thereafter to 350,100 bpd in 2022, compared to the fall forecast at 344,100 bpd.

The price forecast, however, rises between the fall and spring forecasts, with the Alaska North Slope West Coast price at $109.21 in the spring forecast, up from $108.67 in the fall forecast, and the ANS wellhead weighted average at $99.66, up from $99.24 in the fall forecast, a change of 54 cents for ANS West Coast and 42 cents for the ANS wellhead weighted average. ●

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FINANCE & ECONOMY

Buccaneer reviewing strategic options

Buccaneer Energy Ltd. is on the market.

The board of directors of the Australian independent recently rejected an offer from an unnamed third party interested in acquiring all the company's ordinary shares, but the company also said it would be willing to negotiate with the bidder on a different offer.

Buccaneer described the bidder as a "credible party which is known to the company and with whom the company has previously discussed the possibility of a business combination," but said the offer "does not properly reflect the value of the company."

Financial advisor hired

The announcement comes several weeks after Buccaneer hired Canaccord Genuity (Australia) Ltd. to be its financial advisor for "strategic alternatives" for its assets.

"Everything's on the table, including farm-ins, investments at the company level, a dual listing on a North American stock exchange or possibly a change of control transaction," Buccaneer Director Dean Gallegos recently told the Wall Street Journal about the review.

Considering the recent offer and interest from other unnamed third parties, the Buccaneer board of directors said it would continue with the strategic review with Canaccord.

Buccaneer believes its market capitalization fails to represent the true value of its assets in the Cook Inlet basin. The 17.8 million barrels of oil equivalent of proven reserves at Kenai Loop, Southern Cross and Cosmopolitan have a present value of $342 million, Buccaneer said, but the company has a market capitalization of only around $66 million.

"We believe a reason for the valuation disconnect could be that we're the only Australian company operating in that basin. … It's difficult for investors to easily compare us with another entity," Gallegos told the Wall Street Journal.

—ERIC LIDJI

● EXPLORATION & PRODUCTION

Import concentration highest since 1997

PETROLEUM NEWS

The concentration of U.S. crude oil imports among the country's top five suppliers is the highest since 1997, the U.S. Energy Information Administration said April 19.

The five top foreign suppliers to the U.S. in 2012 were Canada, Saudi Arabia, Mexico, Venezuela and Iraq, accounting for almost 72 percent of U.S. net crude oil imports, EIA said, up 8 percent over the past three years.

The agency said Iraq replaced Nigeria as the fifth-largest supplier in 2012.

Net crude oil imports from the five countries averaged almost 6.1 million barrels per day in 2012, "even as total U.S. crude oil imports fell to their lowest level since 1997," EIA said, with the share of the top five suppliers up from 64 percent in 2009, at 72 percent the highest since reaching almost 73 percent in 1997.

U.S. crude oil imports from Canada were a record 2.4 million bpd, up 8 percent from 2011. Imports from Saudi Arabia averaged almost 1.4 million bpd, up 14 percent from 2011, and the highest since 2008. Imports from Mexico averaged 972,000 bpd, down almost 12 percent and below 1 million bpd for the first time since 1994, "reflecting the steady decline in Mexico's crude oil production," EIA said. Crude oil imports from Venezuela rose 4 percent to 906,000 bpd, EIA said, the first increase since 2007, as that country's state oil company sent more crude to U.S. refineries which was exported back to Venezuela as gasoline and other petroleum products.

Crude oil imports from Iraq averaged 474,000 bpd, up slightly more than 3 percent since 2011, moving Iraq ahead of Nigeria as the fifth largest supplier to the U.S. for the first time since 1999. Imports from Nigeria averaged 405,000 bpd in 2012, down 42 percent from 2011 and the lowest since 1985, EIA said, with U.S. domestic production of "light sweet crude oil of similar quality to Nigerian crude and lower demand for light sweet crude from United States East Coast refineries" contributing to the decline. ●

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CANADIAN BEAUFORT

relief well capability.

"Timely regulatory outcomes that are satisfactory to many stakeholders would be necessary to enable the joint venture" the company said.

At least three years

The project description and EIS are usually at least three years ahead of drilling, depending on how long public hearings last, according to an information package Imperial has distributed to regulators and local communities.

Imperial estimates the regulatory process could be completed as early as 2015 and would be followed by an economic feasibility study which would include identifying the most appropriate drilling system.

If the partners decide to embark on an exploration program, Imperial would expect to file an application with the NEB for permission to drill about four to six years before it would spud a well, allowing time to arrange a drilling system.

The drilling plan for each target would vary depending on location, water depth, the geologic zone and the predicted reservoir pressure.

On Exploration Licenses 476 (Ajurak) and 477 (Pokak) locations would be in water depths ranging from about 1,300 feet to 2,300 feet and have geological targets with total vertical depths subsea ranging from 12,500 feet to 22,300 feet.

Records indicate that manageable ice conditions average about 120 days from May to November, but the scope and length of drilling activities would vary. Imperial expects the program would cover three or more seasons, with the results determining whether further drilling would be needed.

Meanwhile, the partners are continuing to review results from the NEB's Arctic offshore drilling review whole evaluating findings from 3-D seismic data gathered from their two large exploration blocks in 2007 and 2008 before the partnership was formed in mid-2010.

Of the two licenses, BP acquired one in 2008 for a work commitment of C$1.18 billion, while Imperial and ExxonMobil obtained their lease for a spending pledge of C$585 million.

Because of delays in the Arctic offshore review, the Canadian government issued fresh exploration licenses, effectively giving the companies until 2019 and 2020 to start drilling and qualify for extended rights if they can establish a significant discovery.

Chevron Canada is continuing to analyze results from last year's 3-D marine seismic program covering 1,412 square miles, 145 miles northwest of Tuktoyaktuk on the shores of the Beaufort.

Norway's Statoil has farmed-in on the 508,000-acre parcel in the deepwater Beaufort, which Chevron acquired in 2010 for a work commitment of C$103.3 million. It is west of the Imperial joint-venture blocks.

—GARY PARK

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MEYER Q&A

more. I know (former Fairbanks House Rep. and hotel owner) Jay Ramras asked the ethics committee about a conflict in tourism. And they did say he had a clear conflict of interest. This committee is made up of public members although there are members from the Legislature as well (one each from House and Senate majority, plus alternative). They ruled that I don't have a conflict. I don't gain personally and financially from this. It is not something that benefits just me. It benefits a lot of people. In fact, you could say it benefits the whole state. So I did not have a conflict of interest. That's why I feel pretty comfortable knowing here are public members of the ethics committee saying that. I've always been clear about it and open about it. I know it's tough for some folks, but with a citizen Legislature, you're going to have fishermen voting on fishery issues; you're going to have union members voting on union issues; you're going to have people in the insurance industry voting on those issues.

Petroleum News: Did you receive any bonus from Conoco Phillips for supporting oil tax reform?

Meyer: Absolutely not. I'm a regular employee who takes a leave of absence to do community service. Then I come back and I have to apply for my job back. I go from being a state senator in Juneau for three to four months. Then I come back to being another Conoco Phillips employee who answers his own phone, answers his own email, writes his own letters, someone who gets his own coffee.

My background is business. A lot of the employees are engineering and geologists, but there are a few business guys and I'm one of those. Most of my career has been on the procurement side or buying side of things. It seems to work better with my colleagues and the company to be in the selling and surplus mode.

This way they are not dependent on me as they are as a buyer. When they put in a request, they need a response quickly and need to get an item to the slope quickly. To have my colleagues cover for me, that puts more pressure on them. This works better for me. They put the items on the side and I take care of it when I come back from Juneau. I have a pretty good idea what they are worth because I spent several years buying them.

Petroleum News: Back in Juneau, what do you think the Legislature accomplished this session on the resource development front?

Meyer: I think this year's was probably the most productive year in the 13 years I've been in the Legislature and years before that when I was watching what was going on in Juneau. To me this was a real trifecta. Not only did we get oil tax reform, something that will make us competitive on a global basis, we dealt with in-state gas A and B.

A was the quick fix, the Band-Aid, if you will, by doing the trucking to Fairbanks of LNG, then B — progressing forward on a more long-term solution, that being the in-state gas line.

Third, which is not resource oriented but resources are 90 percent of our budget, coming up with a lean, responsible operating and capital budget. All three of our major goals were accomplished.

Petroleum News: What do you believe you accomplished with SB 21? It wasn't a slam dunk as far as the final passage votes either with the Senate or House.

Meyer: I think the fact that the vote was close is a good thing. It tells me we found equilibrium; we found the sweet spot. We made adjustments to become more competitive. It means we get less revenue coming in, but hopefully we'll get more production so the revenue that we lose we'll make up.

At the same time, we are maximizing the revenue we will receive. To me a close vote doesn't concern me. If it was a vote of 40-0 and 20-0, that would concern me a lot more, especially on an issue like oil tax reform. Probably my biggest concern with what we finally got passed — and as you know each committee adjusted it a little bit — in my committee the overall government take was 64 percent for legacy fields and 60 or 61 percent for the new oil.

That is the thing that concerns me the most. I'm afraid what you might see is the investment might go to the new oil because of the lower tax rate and not as much to the legacy fields because the bulk of the oil is in the legacy fields. The easy stuff in the legacy fields has been done. Now it's the more difficult, the heavy oil or the oil trapped within the various stratigraphic rock and I'm a little concerned the investment dollars outside the legacy fields and we'll miss out on a big chunk of oil that's within the legacy fields. It's still a lot better than ACES and the big steep progressivity curve that takes away incentive to invest because there is no upside for you.

*Petroleum News: You've addressed two in-state gas issues: LNG for Fairbanks and the in-state gas line with House Bill 4. Do you still want to keep an eye on a prospective prize for a large-*diameter line?

Meyer: I do. I'm hoping that ultimately the plan the governor is working on with the producers will marry up with HB 4. I think HB 4 is going to push that process along a little quicker. If it doesn't work that the two marry up, we will still have the smaller line. We've waited for 30 some years for the big line to get built and it hasn't been built. We need the gas for our own in-state needs. I think it's good that we are going forward with HB 4. Hopefully it marries up with what the producers have planned so they take it over and build it.

Petroleum News: One of the concerns with HB 4, and it didn't play out as much, if you look at the votes, was the Alaska Gasline Development Corp. being a standalone operation and having more distance between AGDC and the Legislature. What are your thoughts on AGDC having that kind of latitude moving ahead?

Meyer: I think you have to do this. Unfortunately — or maybe fortunately — the Legislature, we only meet once a year for 90 days. If you have to keep coming back to the Legislature for approval, that slows down the whole process. As you know we already have a shortage of natural gas in Southcentral, here in Anchorage and on the Kenai Peninsula. I think it's fine. They need to be able to move and move quickly. ●

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Oil Patch Bits

Northwest Technical Services

Northwest Technical Services was incorporated in the State of Alaska in 1980. Its original mission was to provide contract design and drafting support to the oil industry in Alaska. Since then, NWTS has expanded its services to include all areas of professional, technical, administrative, and craft personnel support. In 1982, NWTS was purchased by PDS Tech.

Theresa G. Guim, General Manager

Theresa Guim is the new general manager for the Northwest Technical Services/PDS Tech Inc. Anchorage office. Guim is the prior human resource director for Alyeska Pipeline Service Co. and has more than 15 years of experience in human resource management. She is a graduate of UCLA Business School of Management; additional academic background includes Bachelor of Science, business management studies at Wayland Baptist University and University of Phoenix.

COURTESY PHOTO

THERESA GUIM

Arctic Wire Rope celebrates 30 years with open house

Arctic Wire Rope and Supply said April 22 that it is holding an open house on May 8 to celebrate 30 years of customer appreciation. "We like to extend a thanks to those who have done business with for so many years", said General Manager Mark Lamoureux. Customer service has been a mainstay for Arctic Wire Rope and Supply, a full-service wire rope and nylon sling manufacturing plant. Also stocking crane and winch lines, rigging hardware, chain and anchors, cordage and can provide onsite rigging inspections.

During the open house there will be a few demonstrations, drawings, as well as representatives from The Crosby Group, the world renowned manufacturer of rigging products, providing its famous Louisiana shrimp boil, and Bridon American, a domestic wire rope manufacturer will also be present.

Arctic Wire Rope and Supply specializes in U.S. made products used in the oil and gas, construction, mining, fishing and marine industries.

Eric McCallum founded the company in 1983. The event, held at 6407 Arctic Spur Road in Anchorage, will be from 4-7 p.m. on May 8.

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

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PUMP STATIONS

operations.

"At best, we probably would not have achieved restart until ... summer, meaning North Slope production would have been shut down for months, and the pipeline and its associated equipment likely would have sustained significant damage," Baldridge said.

Such a long shutdown of Alaska's most important physical asset would have been a financial calamity for the state.

Behind schedule, over budget

Baldridge's remarks, signed June 14, 2011, are among extensive filings in a huge tariff battle now pending before the Federal Energy Regulatory Commission and the Regulatory Commission of Alaska.

The issue is to what extent the pipeline owners may recoup their strategic reconfiguration costs from rate payers. Two companies that ship oil on the line, Anadarko and Tesoro, argue the project was poorly conceived and has been plagued by mismanagement and massive cost overruns.

The state likewise is arguing a substantial portion of strategic reconfiguration costs should be disallowed from carrier rate bases. Higher oil transportation costs have the effect of reducing state royalty and production tax revenue, and state lawyers told legislators in February that hundreds of millions of dollars are at stake in the tariff litigation.

Regulatory filings show that strategic reconfiguration is years behind schedule, and far over the original budget.

The pipeline owners sanctioned, or approved, the project in early 2004 at $242 million.

Work to modernize three of the pipeline's main pump stations has been completed. These are stations 3, 4 and 9. Work continues on Pump Station 1 and, according to the state, isn't expected to wrap up until the end of 2014.

The owners and the state agree that strategic reconfiguration costs have exceeded $700 million so far.

The 2011 drama

Alyeska is an Anchorage-based consortium that runs the pipeline on behalf of owners BP, ConocoPhillips, ExxonMobil and Chevron.

While Alyeska acknowledges strategic reconfiguration has experienced some bumps, managers say the new pumps, turbine generators, electric motors and other upgrades are working as designed and are proving to be wise and needed investments. The program is allowing Alyeska to automate its pump stations, save maintenance costs and reduce the risks associated with the line's aging original equipment, they say.

The new equipment really showed its value in early 2011, said Baldridge, who started at Alyeska in 1977, the year the pipeline began operations.

On Jan. 8, 2011, an oil leak at Pump Station 1 forced a three-day pipeline shutdown as Alyeska looked for the source of the leak.

A shutdown in the frigid Interior Alaska winter is a big problem for Alyeska, bigger than it used to be. Because of declining production from North Slope fields, the pipeline is moving much less oil than it once did, and the oil takes longer to reach the Valdez tanker terminal. If the warm oil stops moving, it can chill rapidly, inviting very serious problems.

Thus, the January 2011 shutdown was extremely worrisome.

"We were concerned that by stopping pipeline flow to contain the leak, the cold weather would preclude us from restarting the pipeline until the summer because wax would have built up, water would have separated from the crude oil, and ice would have built up in the pipeline at low areas and on the mainline valves," Baldridge said.

During the shutdown, he said, the oil temperature dropped at several locations to a point where slush and ice likely were forming in the pipeline.

Meantime, North Slope oil field operations, limited to only 8 percent of normal production, faced "even greater jeopardy" with the potential for wells and gathering and transit lines to freeze and fail, Baldridge said.

Federal and state regulators fully supported Alyeska's scramble to fix the Pump Station 1 leak and restart the pipeline, he said.

Crucial to the restart was the ability of the newly reconfigured pump stations to recirculate oil. That is, to move oil through the pump stations multiple times. This adds frictional heat to the crude.

After the restart, the pipeline would be shut down for another 58 hours to finish the leak repairs. This led to oil in the pipeline cooling even further, to "dangerously low levels," Baldridge said.

Alyeska again used the new pumps and recirculation lines at stations 3, 4 and 9 to heat oil. After the pipeline restarted, it took more than three weeks to clear the line of cold oil and achieve normal operations, he said.

Baldridge said he was "convinced that the legacy equipment would not have been able to generate enough heat to restart the pipeline in the winter after the 2011 repair shutdown."

Lawyers for the state, however, are skeptical. They argue much of Alyeska's strategic reconfiguration was unnecessary and "imprudent." ●

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UMIAT TESTING

The results from Umiat No. 18 will be the first from the prospect since 1979, when the U.S. Navy drilled the last well at the oil field in the foothills of the Brooks Range.

Previously, Linc said it would drill Umiat No. 18 vertically into the Lower Grandstand formation to collect five 60-foot sections and continue below the Lower Grandstand "to assess the deeper resource potential." In addition to Umiat No. 18, Linc is drilling the Umiat 23-H well this winter. Umiat 23-H is designed as a directional well into the same Lower Grandstand interval to provide "comparative flow testing" for economic purposes.

Earlier this year, Linc announced that the Umiat No. 18 well had collected 300 feet of core and encountered 100 feet of net oil pay in the Lower Grandstand formation.

The Umiat prospect straddled the boundary between state lands and the federal National Petroleum Reserve-Alaska. This winter, Linc has been drilling on its federal acreage.

A long time coming

The results of the flow testing will provide the best data from Umiat in 34 years.

The U.S. Navy drilled 12 wells at Umiat between 1946 and 1979. The program established the presence of a sizable oil field, but the federal government ultimately decided the prospect was too remote and too technically complex to be economic.

The earlier wells include a mix of dry holes and flow tests as high as 400 barrels per day.

A combination of higher oil prices and improved technology has brought string of independent oil companies to Umiat over the past decade and a half, most recently Linc.

Linc wanted to drill five wells at Umiat last winter, but weather and other delays forced it to postpone the program by one year. The company originally planned to drill between four and six wells this winter, but additional weather delays forced the company to scale the program back to two wells. Linc said it plans to finish the program next winter.

The additional work slated for next year includes a Class II disposal well.

According to a recent third party estimate, Umiat contains more than 1.2 billion barrels of oil in place with proved and probable reserves of 154.5 million barrels of oil equivalent.

Linc anticipates peak production of around 50,000 barrels per day from Umiat.

—ERIC LIDJI

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QUGRUK WELLS

Exploration Co. holds a 7.5 percent working interest.

The companies plan to return to the region next winter, according to Repsol.

Praising tax reform

Repsol connected the program to Senate Bill 21.

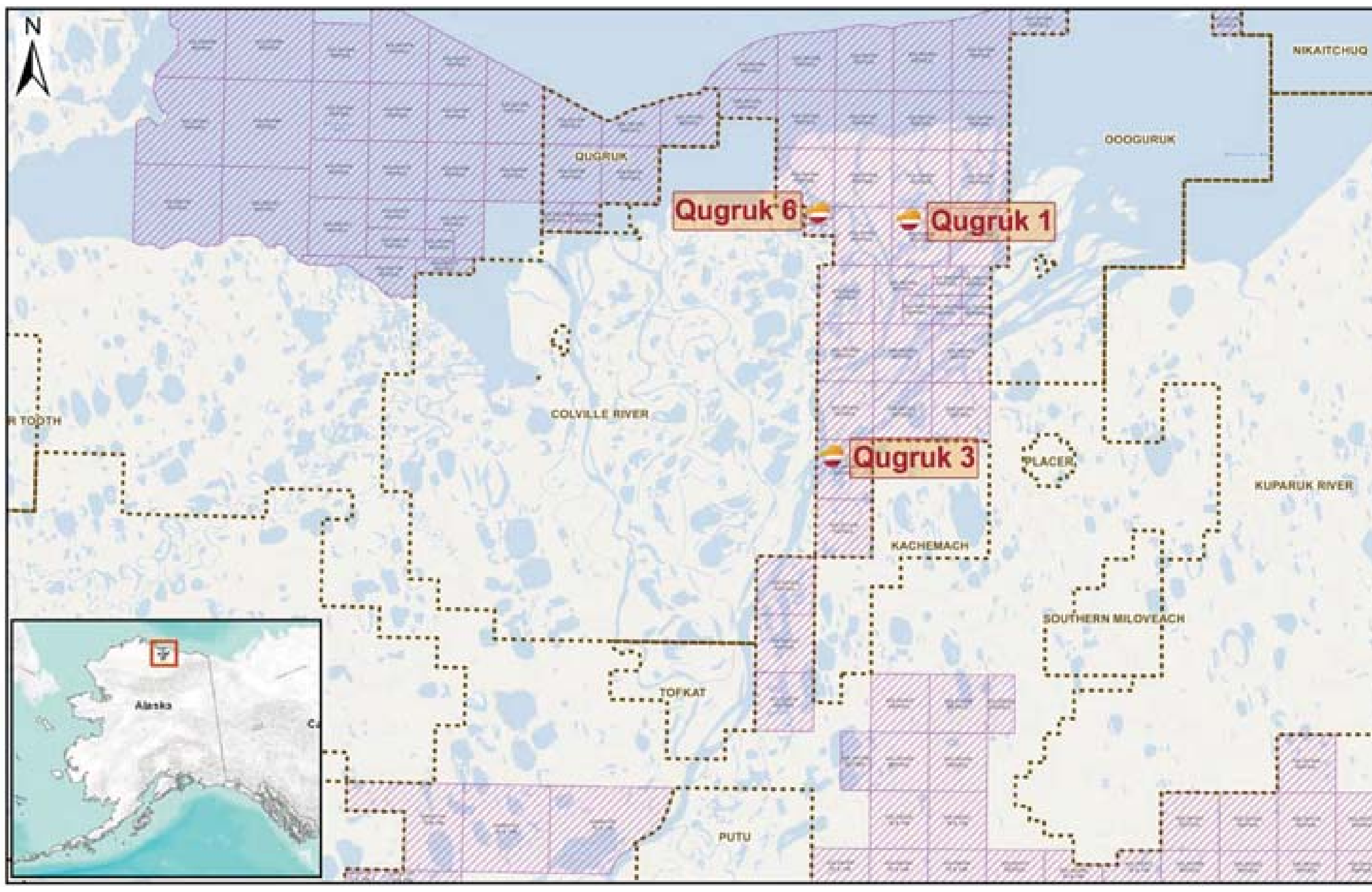
"Recent tax reform passed in Alaska was a critical factor in ensuring the development of this project, where extreme climate conditions and geographical remoteness result in high operating costs," the company said in a statement.

Shortly before Repsol arrived in Alaska in March 2011, its future partner Armstrong connected exploration activities to a change in the state fiscal regime for oil production.

In a letter to the House Resources Committee in early 2011, Armstrong Vice President Ed Kerr praised House Bill 110, an earlier version of the recently approved legislation.

"HB 110 will have a significant impact on our capital expenditures and futures activities in Alaska. The improved fiscal terms as proposed by HB 110, particularly the portions of the bill that apply to activities outside of existing units, will give us the needed incentive to not only drill multiple new wildcat and delineation wells, but the motivation to drive certain projects to development." Kerr also cited "more than a dozen ideas outside of existing producing units" that Armstrong hoped to drill and test over the next several years," adding, "In many cases we know the oil is in place. The improved fiscal terms as provided in HB 110 will greatly affect whether these projects will get developed."

And in November 2012, Bill Hardham, Alaska operations manager for Repsol, called the North Slope a "key area" for the company, but also said that early planning for development strategies for its leases highlighted "the challenges we have" as well as "the need for production tax reform here because we do have some challenges ahead of us."



Repsol arrived in Alaska through a major deal in early 2011, picking up a 70 percent working interest in some 494,211 acres of 70 & 148 and GMT Exploration Co. leases south of the Kuparuk River unit, in the White Hills area and near the Ooguruk unit.

Internationally, Repsol is investing heavily in exploration.

By acquiring acreage in 14 new countries since 2004, Repsol was able to post a reserve replacement ration of 204 percent last year, according to the company. The current strategic plan includes a goal to replace reserves by at least 120 percent each year through 2016 and to increase production by 500,000 barrels of oil equivalent per day by 2016.

To meet those goals, Repsol plans to spend 80 percent of its roughly $24.8 billion capital budget over the coming five years on exploration and production areas, such as Alaska.

Discovery in two years

Repsol arrived in Alaska through a major deal in early 2011, picking up a 70 percent working interest in some 494,211 acres of 70 & 148 and GMT Exploration Co. leases south of the Kuparuk River unit, in the White Hills area and near the Ooguruk unit.

From the start, the companies viewed the transaction as the beginning of a partnership, with Repsol operating and financing activities and the independents (especially Armstrong) using previous North Slope experience to guide permitting efforts.

The momentum behind the program was clear from the numbers: of the $768 million Repsol spent on the deal, $750 million was reportedly slated for exploration work.

The partners began quickly by planning a five-rig, five-pad and 15-penetration program in the winter of 2011-12. In response to local concerns and regulations, Repsol eventually decreased the program to nine penetrations from three pads using three rigs.

A blow-out at the Qugruk No. 2 well in February 2012 forced Repsol to suspend drilling activities for weeks, but the company ultimately completed the Kachemach No. 1 well to a depth of about 10,100 feet, and the Qugruk No. 4 well to a depth of about 7,700 feet.

This winter, Repsol again attempted a three-rig three-pad program. ●

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CONOCO EARNINGS

ties as we keep," Bob Heinrich, vice president of finance for ConocoPhillips Alaska said. "We are encouraged by improvements the legislature and Governor have made to the state's production tax and believe it should lead to more North Slope investment and production, even though the changes in the tax structure will not take effect until January 1, 2014."

Although falling oil production in Alaska and rising oil production elsewhere promises to shift the balance in the future, Alaska remains a profitable segment for the company. By comparison, the company reported adjusted quarterly earnings of $431 million in Europe, $133 million in Canada, $105 million in the Lower 48 and $28 million in Latin America.

ConocoPhillips earned $918 million from its Asia Pacific and Middle East segment.

Production falling

With liquids prices remaining relatively stable in recent quarters, oil production continues to be the driving factor behind ConocoPhillips' profits. And it is driving them down.

ConocoPhillips produced 218,000 barrels of oil equivalent per day in Alaska in the first quarter, down from 222,000 boe per day (or 1.8 percent) in the fourth quarter of last year and 236,000 boe per day (or 7.6 percent) in the first quarter of 2012. ConocoPhillips said this drop "primarily" reflected normal field decline, as opposed to maintenance work.

Crude oil production fell 3 percent quarter-over-quarter and 8.6 percent year-over-year to 190,000 barrels per day while gas production stayed level quarter-over-quarter but fell 5 percent year-over-year to 56 million cubic feet per day. Natural gas liquids production rose slightly quarter-over-quarter but was level year-over-year at 18,000 barrels per day.

Production will likely be further impacted this year by a major turnaround in Alaska, part of a maintenance program also covering assets in Canada, the Lower 48 and Indonesia.

By comparison, ConocoPhillips produced 475,000 barrels of oil equivalent per day in the Lower 48 in the first quarter, level quarter-over-quarter but up 5.3 percent year-over-year.

As ConocoPhillips develops its oil-rich assets in the Permian Basin and Eagle Ford Shale of Texas and the Bakken formation of North Dakota, its production mix in the Lower 48 is

> *"You won't really see any significant change in the short term, but the issue is: Given the new fiscal regime, are incremental capital investments now competitive? We think they will be, and we're taking that through our overall planning process this year and we'll be more equipped to talk about that later in the year."* **—Conoco Phillips EVP of Exploration and Production Matt Fox**

increasingly tilting toward oil. The company produced 148,000 barrels per day of crude oil in the Lower 48 during the first quarter, up from 136,000 bpd (or 8.8 percent) in the fourth quarter of last year and 117,000 bpd (26.4 percent) in the first quarter of last year.

ConocoPhillips produced 1.4 billion cubic feet of natural gas per day in the Lower 48 during the first quarter, down slightly both quarter-over-quarter and year-over-year.

With those figures, liquids now represent half of the production mix in the segment, up from 45 percent a year ago, and the company expects the figure to grow this year.

Companywide, ConocoPhillips produced nearly 1.6 million barrels of oil equivalent per day during the first quarter, down slightly both quarter-over-quarter and year-over-year.

Prices stabilizing

The drop in Alaska earnings came despite a rise in prices.

ConocoPhillips reported an average price of $110.79 per barrel for Alaska liquids during the quarter, up from $106.91 in the fourth quarter of last year but down from $112.20 in the first quarter. Companywide, ConocoPhillips reported an average price of $106.20.

For natural gas, ConocoPhillips reported an average price of $5.20 per thousand cubic feet in Alaska, up from $4.28 in the fourth quarter of last year and $4.68 in the first quarter of last year. Companywide, ConocoPhillips reported an average price of $5.74.

The tax question

The figures are the first since the Alaska Legislature approved a major revision to the state fiscal regime covering oil production — a revision ConocoPhillips desired.

Soon after the legislation passed, ConocoPhillips announced plans to bring an additional rig to the Kuparuk River unit to increase production from the legacy oil field. "We are currently analyzing the possible impact to our business, including where we could or would increase investment in Alaska, and we expect to provide more details on our future plans over time," ConocoPhillips CFO Jeff Sheets said during an earnings call April 25.

Asked when the investments might impact production, EVP of Exploration and Production Matt Fox said, "You won't really see any significant change in the short term, but the issue is: Given the new fiscal regime, are incremental capital investments now competitive? We think they will be, and we're taking that through our overall planning process this year and we'll be more equipped to talk about that later in the year."

For now, the current financial figures reflect the previous fiscal regime.

ConocoPhillips reported an effective income tax rate of 35.5 percent for Alaska during the first quarter. The figure jumps to 61.6 percent when other taxes are included and the company said the marginal tax rate at current prices is around 82 percent in Alaska.

In dollar figures, ConocoPhillips said it paid an estimated $1.2 billion in state and federal obligations in Alaska in the first quarter, of which $900 million went to the state.

Among its other divisions, ConocoPhillips reported effective income tax rates of 49.1 percent in the Lower 48 and Latin America, 22.2 percent in Canada (after excluding special items that drove the actual figure up to 213.7 percent) and 63.8 percent in Europe.

ConocoPhillips only breaks out effective government share for Alaska.

Companywide, ConocoPhillips reported an effective income tax rate of 46.6 percent.

Cassin discovery

While taxes remained level, spending increased in the quarter.

ConocoPhillips spent $262 million in

> *ConocoPhillips earned $918 million from its Asia Pacific and Middle East segment.*

Alaska during the first quarter, up from $232 million in the fourth quarter of last year and $186 million in the first quarter of 2012.

ConocoPhillips reported $135 million in depreciation, depletion and amortization expenses in Alaska in the quarter, up slightly quarter-over-quarter and year-over-year.

Among the projects ConocoPhillips conducted during the quarter was the Cassin No. 1 well, which Fox described as a "wildcat." ConocoPhillips made a discovery at the prospect, but details are scarce. Earlier this year, ConocoPhillips drilled the well to meet work commitments of its Bear Tooth unit in the National Petroleum Reserve-Alaska.

ConocoPhillips has made discoveries in the NPR-A through its previous exploration work, but development has been constrained by permitting and infrastructure. The company is currently working on its first NPR-A development project with the Alpine West/CD-5 satellite, a project that could pave the way for future westward expansion.

Speaking about the decision to delay Chukchi Sea exploration planned for next year, Fox said ConocoPhillips was "on the cusp of having to make some very significant commitments" for equipment, but felt unconfident about making those commitments given the current regulatory environment. "We felt that the prudent thing to do was to take a pause there and let things evolve a little bit before decide to drill those wells."

Asked if ConocoPhillips would explore in 2015, Fox said, "Potentially," adding that the decision ultimately depended on whether the regulatory environment inspired confidence. ●

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