Petroleum news

page 3 Stedman intent on oil tax fix, calls for continued focus on reform

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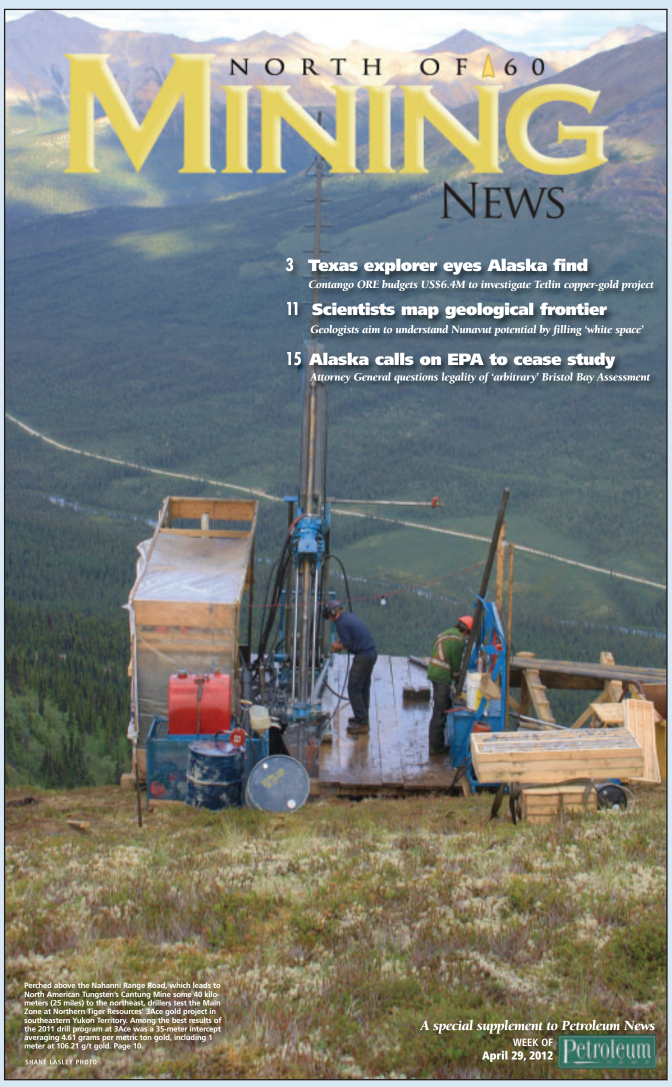
April Mining News inside



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

Shale oil & gas paradigm shift drives US, world energy outlook

Like the proverbial hurricane triggered by the flapping of a butterfly's wings, the emergence of horizontal drilling and hydraulic fracturing techniques for the development of shale oil and gas is blowing a gale-force wind of change through the U.S. energy scene.

A recent report to Energy Secretary Steven Chu by the National Petroleum Council said that North America could increase oil production by 10 million to 12 million barrels per day by 2035, a prediction that may be an underestimate, Lou Pugliaresi, president of the Energy Policy Research Foundation, told the Alaska World Affairs Council on April 20.

see **SHALE OUTLOOK** *page 17*

Ups and downs in fracking sector in Nova Scotia, New Brunswick

Companies searching for commercial deposits of shale gas in eastern Canada are faced with mixed messages from provincial governments about the use of hydraulic fracturing.

At about the same time, the Nova Scotia government said it would extend by another two years to summer 2014 a moratorium on fracking, while the neighboring New Brunswick government granted a five-year license to Calgary-based Windsor Energy to explore and drill for gas in that province.

Earlier in April, the Quebec government added another year to its freeze on fracking imposed a year ago, pending results from a report now expected in 2013. That study is focused on the Utica formation, which has 50 trillion cubic feet of estimated recoverable gas.

The Central Maritimes region, which straddles the New

see **FRACKING SECTOR** *page 17*

GOVERNMENT

Canada sets limits

Federal cabinet to make final decisions on major energy projects

By GARY PARK

For Petroleum News

SHANE LASLEY

JOE OLIVER

The Canadian government has drawn a clear line between the industry and its foes when it comes to handling regulatory applications for energy projects that are deemed to be in the "national interest."

Following through on a promise in the 2012-13 federal budget introduced in March, the administration of Prime Minister Stephen Harper has issued the broad strokes of a policy to streamline environmental reviews of major energy and mining projects that it estimates could attract C$500 billion in new investment over the next decade.

"We have to compete with other resource-rich countries for fast-growing markets and scarce capital," said Natural Resources Minister Joe Oliver.

"With scarce resources, it is counter-productive to have the federal and provincial governments completing separate reviews of the same projects," he said. "We need to tap into the tremendous appetite for resources in the world's dynamic emerging economies — resources we have in abundance."

In unveiling the centerpiece of the government's "Responsible Resource Development" plan, Oliver listed some of the constraints that will restrict the activities of the "limited number who have a radical agenda."

see **PROJECT DECISIONS** *page 18*

FINANCE & ECONOMY

Conoco earns $616M

Production bump probably result of 2011 TAPS shutdown; prices drive profitability

By ERIC LIDJI

For Petroleum News

ConocoPhillips earned $616 million in Alaska in the first quarter of the year, as a rare combination of rising oil prices and production bumped profits 12 percent year over year.

The unusual uptick in Alaska oil production volumes, though, is caused in part by a four-day shutdown of the trans-Alaska oil pipeline in January 2011 and not necessarily increasing activity this year. And the slight bump comes as ConocoPhillips is rapidly increasing its liquids output from the Lower 48, particularly from unconventional plays.

The largest operator in Alaska produced 226,000 barrels of oil and natural gas liquids per day in the state in the first three months of the year, up 5 percent from 214,000 bpd in the first quarter of 2011 and down slightly from 227,000 bpd in the fourth quarter of 2011.

ConocoPhillips realized an average sales price of $112.20 per barrel for Alaska crude oil but only earned $76.40 per barrel for Lower 48 crude during the quarter.

By comparison, ConocoPhillips produced 201,000 bpd of liquids from its Lower 48 portfolio, up 34 percent year over year and 8 percent quarter over quarter, where the company operates in the

see **CONOCO EARNINGS** *page 18*

EXPLORATION & PRODUCTION

Shale oil fairway leased

Duncan briefs senators on Great Bear's progress; state land for shale liquids taken

By PETROLEUM NEWS

JUDY PATRICK

ED DUNCAN

In a briefing to the Senate Resources Committee on April 25, Great Bear Petroleum's top executive said all state acreage prime for shale liquids in northern Alaska had been leased, the last of the tracts snapped up at the state's North Slope lease sale in December.

Identifying his company as the "first movers on Alaska shale oil," Duncan said, "the fairway for oil and gas shale development on Alaska state lands is fundamentally leased for oil and liquids, in our opinion, at this time."

The Shublik is responsible for probably 60 percent-plus of the oil reserves known to exist on the North Slope … and importantly mineralogically, it's a carbonate. It's a black limestone. (Not shale.)

1 2 SERIES

He mentioned both leases won by Great Bear at the Dec. 7 sale that filled a hole in its acreage (see page 2 of Duncan's overheads at www.petroleumnews.com/pnfm/Great_Bear_120425.pdf), and "approximately 100,000 acres" won by shale player Royale Energy out of San Diego.

see **SHALE FAIRWAY** *page 19*

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

● GOVERNMENT

Stedman calls for focus on oil tax reform

Finance co-chair calls ACES dysfunctional, criticizes Parnell's approach to fixing it, calling for more administration analysis

By STEFAN MILKOWSKI
For Petroleum News

As co-chair of the Senate Finance Committee, member of the Senate Resources Committee, and a financial advisor with a knack for number crunching, Sen. Bert Stedman has played an outsized role in the last several years of oil tax debates.

Stedman advocates tax reform — both for certain tax reductions and for structural changes to the tax — but has also been one of the strongest critics of Gov. Sean Parnell's proposals to modify Alaska's Clear and Equitable Share, or ACES.


SEN. BERT STEDMAN

Stedman helped craft the Senate's alternative, SB 192, which passed out of the Resources and Finance committees but never got a floor vote.

In an interview on April 25, Stedman called for more analysis from the administration and warned that support for Parnell's new plan was dwindling by the day.

Petroleum News reached Stedman again on April 26, after the governor's announcement to remove oil taxes from the special session agenda.

The interview below covers both conversations.

April 25

Petroleum News: Let's start with the regular session. What happened to SB 192?

Stedman: It didn't get the votes to pass.

When the Finance Committee put the committee substitute on the table, frankly, the Department of Revenue checked out. Also, there are differences of opinion (in the Senate) over the magnitude of financial relief to give to incremental oil production in the legacy fields.

Petroleum News: What do you think of the governor's new proposal?

Stedman: It's dysfunctional. You give an allowance concept to target particular areas you're trying to stimulate, say new production. Doing the allowance concept over the entire basin is just nonsensical. There are issues embedded within ACES that need to be fixed that this bill doesn't address.

The longer that bill is out in the hearing process, the less support it has. Almost daily, the support for it is dropping. You can feel it in the building.

Petroleum News: So it doesn't have much chance of passing as is?

Stedman: I'd say there's no chance of it passing as is. It doesn't fix the problems. All it does is move cash.

Petroleum News: In a recent speech, the governor said the fundamental problem is that companies can take their profits from Alaska and invest in places where they'll get a better rate of return. Is that true?

Stedman: I'm sure you could find a lot of places it is true. But you better broaden out the scope. There are two big pieces to the equation. One of them is the prospectivity of your basin. The other one is your fiscal terms. We're discussing, on the fiscal terms side, a very narrow area within that.

Petroleum News: Do you think it would be possible to increase production at Prudhoe Bay and Kuparuk by reducing taxes?

Stedman: Is it possible? It's possible to put a man on the moon.

Is it likely to happen? That should be the question. If you adjust your fiscal terms down, will an industry respond in increased production? That's an open question.

The magnitude of what you actually need to move the production in any meaningful way has not been in front of any committee that I'm aware of, other than a comment by Exxon's executives basically giving a ballpark feel of about $3 to $5 billion a year (industry investment).

Q AND A

Petroleum News: The governor claimed we could have 100,000 new barrels of production from existing fields in two years.

Stedman: That's ridiculous.

Petroleum News: So it's not just a question of more infill drilling?

Stedman: If you want a million barrels out of the state's fields, you're not going to ever get it. You've got the technology barrier, financial constraints, and other constraints such as processing facilities.

There's a lot more to the equation than just moving a guy's internal rate of return up or down a little.

Petroleum News: In committee, when lawmakers ask for economic analysis of specific projects, the Department of Revenue continues to say, You have to ask industry. Is it OK to rely on industry for information like that?

Stedman: The department should be able to come forward and put a presentation in front of the Finance Committee and the Resources Committee to justify their position and not just say, Go ask industry. That's unacceptable.

That being said, you want to cross-reference the discussion with industry to see if they feel it's technically possible and financially feasible.

Petroleum News: In SB 192, why did you want to

see **STEDMAN Q&A** page 14

MEETINGS & CONFERENCES

AEDC to issue projects, jobs forecast

The Anchorage Economic Development Corp. will release its latest 10-year projection for mining, oil and gas development at a May 2 event in Anchorage.

The 2012 Resource Extraction 10-Year Project Projection will be unveiled on Wednesday, starting at 4:30 p.m. in the Anchorage Downtown Marriott Hotel.

Participating in the event will be Alaska's U.S. Senators Lisa Murkowski and Mark Begich, who will share their thoughts on the future of oil and gas and mining opportunities in Alaska over the next decade from a federal perspective.

The annual report recaps "the current state of the oil and gas and mining industries and then projects the jobs and investment impacts of projects proposed for the next 10 years," said Bill Popp, president and CEO of AEDC.

Last year's 2011 projection document can be viewed at http://www.aedcweb.com/aedcnew/index.php/research/category/1-reports.

Northrim Bank is sponsoring the 2012 Resource Extraction 10-Year Projection. People interested in attending can register at www.AEDCweb.com.

—PETROLEUM NEWS

● GOVERNMENT

Alison Redford rules Alberta

Posts 12th successive victory for Progressive Conservative party, gains mandate to seek Canadian backing to ship oil sands crude

By GARY PARK
For Petroleum News

Alison Redford gave Alberta's governing Progressive Conservative party its 12th successive election victory since 1971 on April 23, earning a ticket to negotiate a pan-Canadian energy strategy which she hopes will open the door to wider domestic and international markets for her province's oil sands crude and natural gas.

In the process she left pollster's scratching their heads and fumbling for explanations after they had consistently forecast a victory for the upstart Wildrose party, or, at the very least, a tight finish.

"We were all wrong," said Ian Large of Leger Marketing. "We were all equally wrong."

Voters, about 20 percent of whom were listed as "undecided" before voting day, apparently decided they were not prepared to swing as far to the right as Wildrose leader Danielle Smith, many of them transferring their votes from the minority Liberal party to Redford, who has emphasized the progressive, rather than conservative element of her party's name.


ALISON REDFORD

Some observers have even suggested that, given Redford's political leanings, Alberta has effectively elected its first "Liberal" government in 91 years.

61 or 87 seats

At the latest count, the Progressive Conservatives will occupy 61 of 87 seats in the provincial legislature, backed by 44 percent of the vote. Wildrose elected 17 legislators with 34.3 percent voting support, the Liberals five and the left-leaning New Democratic Party four.

Wildrose was formed four years ago in a breakaway from the Conservatives after a disastrous attempt by Redford's predecessor, Premier Ed Stelmach, to overhaul Alberta's royalty regime — a mishandled plan that cost billions of dollars in investment and thousands of jobs.

The electorate wasn't even swayed by Smith's promise to return 20 percent of all provincial budget surpluses to Albertans, starting at an estimated C$300 per person in 2015, giving everyone a "direct share in the success of the province's energy sector."

Nor were voters deterred by Redford's commitment to increase health and education spending, despite a recent run of budget deficits that will not be eliminated until 2015.

Keystone immediate priority

Having swept to victory, Redford can now seek cooperation among Canada's 10 provinces and three territories and lay the foundation this summer for a Canadian Energy Strategy to open the way for pipelines and infrastructure to handle a tripling oil sands production to 3.5 million bpd by 2020.

Her immediate priorities are to secure approval for TransCanada's Keystone XL pipeline to the U.S. Gulf Coast, plans by Enbridge and Kinder Morgan to export crude bitumen to Asia and moves by TransCanada and Enbridge to increase pipeline capacity to Eastern Canada to reduce current imports of 500,000 barrels per day to that region.

In less than seven months as premier, Redford has struck conciliatory tone carrying her message in support of Keystone XL to Washington, D.C., emphasizing her respect for the "sanctity" of the U.S. regulatory process.

She has also made a case for the economic benefits across North America of oil sands development and outlined her government's efforts to tackle the environmental challenges facing the sector.

Redford said during the election campaign she believes that offering "honest, workable solutions will make it harder for people to say 'no'."

In her victory speech, she said the election was "about choice, a choice to put up walls or build bridges … tonight Alberta chose to build bridges."

Smith had talked about building a "firewall" around Alberta to protect the province from outside attempts to limit growth of the oil sands and scorned Redford's push for a national energy strategy, arguing Alberta alone could "lead the world in responsible, safe and reliable energy development."

Redford's campaign platform included

see **REDFORD RULES** page 5

CORRECTIONS

Distance misstated

In a story in the April 15 issue of Petroleum News the distance between the Central Mackenzie Valley of the Northwest Territories and the heart of the Bakken in North Dakota was misstated. The two areas are 1,600 miles apart, not 4,200 as stated in the story.

Applicability of governor's new tax bill

A story in the April 22 issue incorrectly described one of the provisions of the governor's new oil tax bill.

Incentives in the bill for new oil apply to North Slope fields not in production or in units on Jan. 1, 2008.

The story said the incentive would apply to Oooguruk and Nikaitchuq, but not to Point Thomson.

That is not correct.

In discussions in House Resources April 24, Deputy Revenue Commissioner Bruce Tangeman said that Nikaitchuq, Oooguruk and Point Thomson would not be eligible for the new oil incentive.

The incentive would, however, be available to projects which Great Bear and Repsol have under way, Tangeman said.

—KRISTEN NELSON

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● FINANCE & ECONOMY

Parnell dumps oil tax change proposal

Governor cites lack of support in Senate for oil tax bill introduced at start of special session April 18; asks for work on HB 9

By KRISTEN NELSON
Petroleum News

Just when the House Resources and Energy committees were on a roll in their House Bill 3001 hearings, Gov. Sean Parnell abruptly withdrew the legislation April 25, citing lack of support in the Senate.

In a late afternoon statement April 25, a week to the day after introduction of his oil tax bill, Parnell said he had signed a supplemental proclamation removing oil and gas production taxes from consideration by the Legislature during the special session.


GOV. SEAN PARNELL

He said the Senate must still take up House Bill 9, the in-state gas pipeline bill, to complete its special session work.

"Stemming Alaska's production decline and growing our economy through increased oil production is extremely important, both now and in the long term," Parnell said in a statement. "But there are some in the Senate who believe that Alaska's oil production decline is a myth. This is an irresponsible disregard for the facts and Alaskans deserve much better."

He called the position of some in the Senate "hardline," and said "the Senate appears incapable of passing comprehensive oil tax reform."

The statement said the governor has the authority to convene special sessions and set agendas, and also has the authority to withdraw a topic from consideration, noting that the Legislature has the power to call itself into special session to consider the same issue.

Hearings to date

The governor's new proposal was introduced April 18, the first day of the 30-day special session, and combined the new-field tax allowance proposal the Senate developed at the end of the regular session, a 30 percent 10-year allowance on both the base tax and progressivity, with a similar approach for existing fields, a 40 percent deduction on progressivity only.

The House has not had an oil tax bill to consider this year, and House Resources, meeting with House Energy, began at the beginning, meeting twice a day, and into the weekend the first week of the special session.

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

Additional oil

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

There was a division of opinion in the Senate Bipartisan Working Majority with some senators believing ACES is working just fine.

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

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

North Slope production is on the decline and Parnell set a goal to increase throughput on the trans-Alaska oil pipeline to 1 million barrels per day (it is currently less than 600,000 bpd).

More throughput would require an increase in investment, so a major issue for the Senate was finding a way to incentivize additional oil production without reducing taxes on existing production.

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

Following that, Senate Finance proposed a change only to taxes on oil from new fields, attaching that to a House bill providing credits and production tax breaks for unexplored or underexplored basins close to communities in need of more reasonably priced energy supplies. The House Rules Committee moved the so-called "middle earth" provision to another bill, and the Senate new oil tax reduction was never considered in the House.

Special session

In announcing the special session tax bill, Parnell said the administration used the Senate's new tax provision, plus a variation of that for existing production.

The bill was very poorly received in Senate Resources, where the governor's team — Commissioner

see PROPOSAL DROPPED page 14

continued from page 4

REDFORD RULES

an investment of C$150 million a year for 20 years to develop new environmental technologies through a recreated Oil Sands Technology and Research Authority.

The agency's goals include clean gasification of feedstocks, such as bitumen bottoms, petroleum coke, biomass, waste and coal and transforming them into synthetic gas and value-added products such as heat, electricity and petrochemical feedstock.

It will also be charged with expanding the alternative energy sector and strategies in biofuels and developing commercial exports for Alberta's clean energy.

A spokesman for the Canadian Association of Petroleum Producers said Alberta has an opportunity to "demonstrate leadership for policy and regulation that enables responsible oil and gas development."

He said the issues of "vital importance" for Alberta include increasing access to key markets in the U.S. Gulf Coast, Eastern Canada and Asia and improving the industry's "environmental and social performance and the transparency of performance reporting."

Davis said there should also be a focus on "communications and outreach to national and international interests." ●

Contact Gary Park through publisher@petroleumnews.com

LAND & LEASING

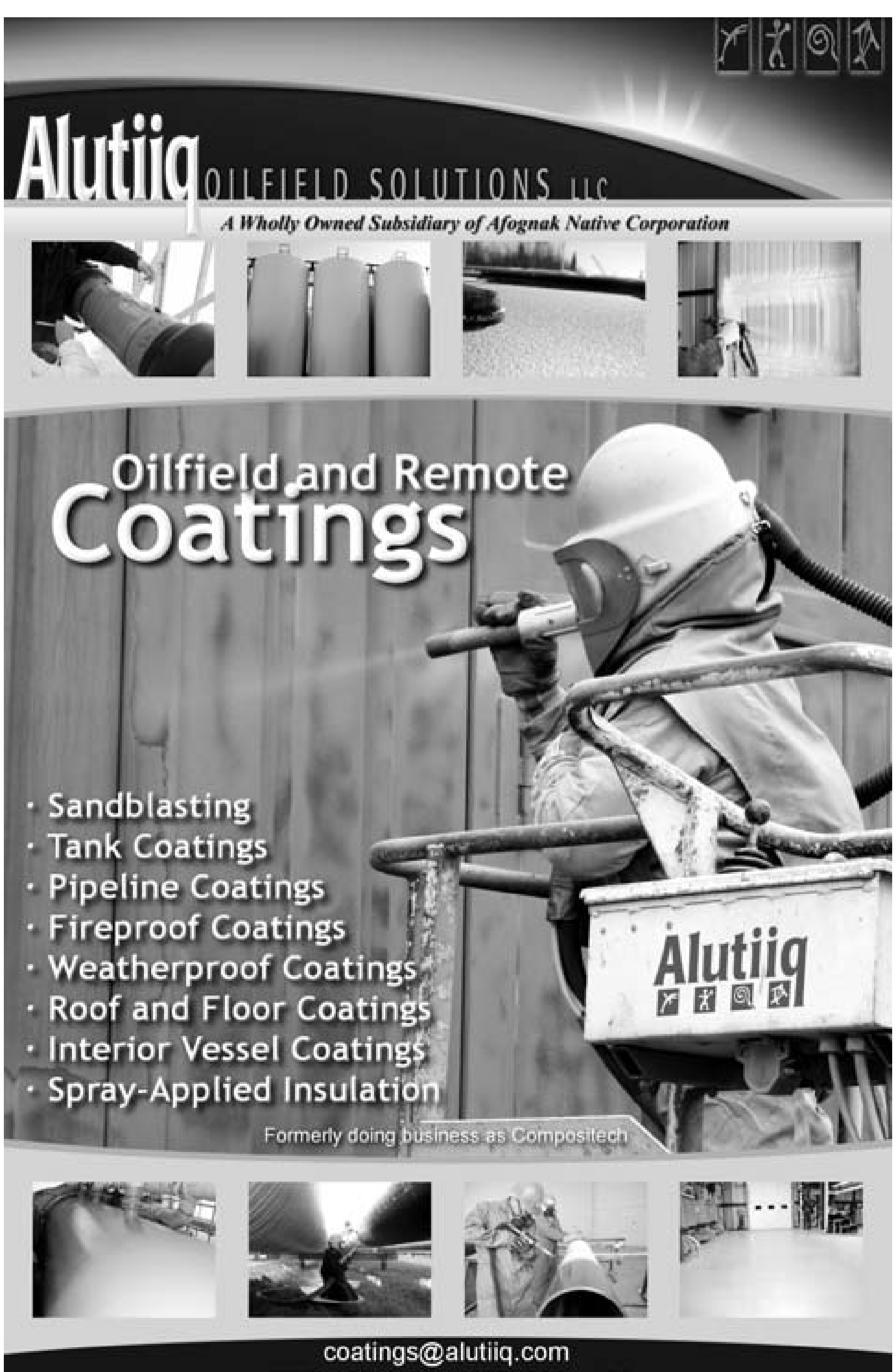
Potential Alaska state and federal oil and gas lease sales

Agency	Sale and Area	Proposed Date
DNR	Cook Inlet Areawide	May 16, 2012
DNR	Alaska Peninsula Areawide	May 16, 2012
DNR	Beaufort Sea Areawide	fall 2012
DNR	North Slope Areawide	fall 2012
DNR	North Slope Foothills Areawide	fall 2012
BLM	NPR-A	late 2012
BOEM	2013 Cook Inlet (special interest)	late 2013
BOEM	Beaufort Sea	2015
BOEM	Chukchi Sea	2016

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.

This week's lease sale chart sponsored by:

Geokinetics



● FINANCE & ECONOMY

BP shareholders look to restart lawsuit

'Derivative' action was brought after the Deepwater Horizon disaster; case has been frozen in Alaska court for several months

By WESLEY LOY
For Petroleum News

Lawyers for some BP shareholders are trying to revive a stalled lawsuit filed in an Alaska court in the wake of the Deepwater Horizon disaster.

The case is a "shareholder derivative" action, which the shareholders filed on behalf of the company against current and former BP board members and executives.

The shareholders allege breach of fiduciary duties, negligence and gross mismanagement in connection with the Deepwater Horizon blowout in the Gulf of Mexico, pipeline leaks and other problems in BP's North Slope operations, and the deadly explosion at BP's Texas City refinery in 2005.

The lawsuit in Alaska Superior Court in Anchorage has been essentially dormant since Aug. 15, 2011, when Judge Sharon Gleason stayed the case pending resolution of a similar suit in federal court in Houston, Texas.

The Texas case has since been dismissed, and now the question has arisen as to the fate of the Alaska suit.

Dismissal urged

A hearing was held April 25 in Anchorage before Superior Court Judge Brian Clark, who now presides over the derivative case because Gleason has moved on to a position on the federal bench.

Richard C. Pepperman II, a New York City lawyer representing the BP board members and executives, argued the case should be tossed, in light of the dismissal of the Texas case.

U.S. District Judge Keith P. Ellison, presiding over the Texas case, ruled on Sept. 15, 2011, that England, where BP is headquartered, is "the far more appropriate forum" for the derivative suit.

Now that the Texas derivative suit has been dismissed, the derivative suit in Alaska's Superior Court likewise "should be dismissed in its entirety," Pepperman argued at the hearing.

The Texas case has since been dismissed, and now the question has arisen as to the fate of the Alaska suit.

Benny C. Goodman III, a San Diego lawyer representing the BP shareholders, saw it differently.

Alaska law applies?

The people Goodman is representing include Jeffrey Pickett, whom Goodman described as an Anchorage resident and BP shareholder long involved in trying to encourage good corporate practices and governance within the company.

Goodman listed a few environmental and safety mishaps in Alaska oil fields that preceded the Deepwater Horizon disaster, and said the company's "ongoing problems" hurt not only BP and its shareholders but also the state.

Yes, the Texas case was dismissed, but that doesn't mean the Alaska case should also be dismissed, Goodman said. He urged the judge to lift the stay and let the case proceed.

While the other side argues England is the proper place for a shareholder derivative suit on behalf of BP, Goodman cited Alaska statutes to argue the London-based company is subject to the same liabilities as a domestic corporation.

"We have a compelling argument here, your honor, that Alaska law applies," Goodman said.

Among the defendants named in the Alaska suit are Tony Hayward, BP's former chief executive, and John Mingé, president of BP Exploration (Alaska) Inc.

Judge Clark posed a number of questions to the lawyers during the hearing, which lasted about an hour and 20 minutes.

"I will take the matter under advisement," he said, adding his decision probably won't come for at least three weeks. ●

Contact Wesley Loy at wloy@petroleumnews.com

NATURAL GAS

Buccaneer begins sales into CINGSA

Buccaneer Energy Ltd. recently began selling natural gas from a Kenai Peninsula well into a new Cook Inlet storage facility, the Australian independent announced April 26.

Enstar Natural Gas Co. is injecting 100 percent of the volumes from the Kenai Loop No. 1 well into its nearby Cook Inlet Natural Gas Storage Alaska, according to Buccaneer.

The well is currently producing 5.1 million cubic feet per day, but Buccaneer said it hopes to increase production "in the short term." Under its contract, Buccaneer must provide at least 5 million cubic feet per day to the facility, but can sell as much as 15 million per day.

Additionally, Buccaneer said it extended its agreement to sell Kenai Loop volumes to ConocoPhillips for use at the liquefied natural gas export terminal in Nikiski. That contract would only go into effect in the storage facility shut down for some reason.

"Based on the economics of the Kenai Loop project and the continued development of CINGSA, we are looking forward to drilling more wells on the project as soon as we complete the acquisition of the Glacier No. 1 drilling rig from Marathon," Buccaneer Director Dean Gallegos said in a statement. "Having the ability to sell increased volumes to Enstar, and any volumes during maintenance periods with ConocoPhillips, allows us the confidence to produce at the maximum efficient rate from the project."

—ERIC LIDJI

● LAND & LEASING

Cook Inlet Energy bags Susitna license

Company now holds exclusive exploration rights on 3 tracts totaling 580,147 acres in lightly explored basin north of Anchorage

By WESLEY LOY

For Petroleum News

Anchorage-based Cook Inlet Energy LLC's Alaska land holdings grew considerably on April 1.

That was the effective date for the little independent's newest exploration license in the Susitna basin, north of Anchorage and west of the Willow community.

The license grants Cook Inlet Energy the exclusive right to explore for oil and gas on 45,764 acres of state land, for a term of five years.

Cook Inlet Energy, a subsidiary of Tennessee-based Miller Energy Resources Inc., now holds three exploration licenses in the Susitna basin, a huge and little explored area.

"We believe our extensive acreage in the Susitna Basin holds excellent potential for Miller, especially for natural gas that sells for a premium in Alaska," Miller's chief executive, Scott Boruff, said in an April 13 press release.

The state's exploration licensing program complements its regular oil and gas leasing program. The idea is to encourage exploration in frontier basins with relatively low or unknown hydrocarbon potential — typically Interior land far removed from the state's existing oil and gas fields.

The Susitna basin has been lightly explored, a state best interest finding from 2003 says. Nine oil and gas exploration wells and four core holes have been drilled in the region. All the exploration wells were dry holes, though some had minor gas shows.

Cook Inlet Energy has assembled three Susitna basin exploration licenses. The first, which the state designates Susitna basin exploration license No. 2, covers 471,474 acres. Another license, Susitna basin No. 4, covers 62,909 acres. The latest license, Susitna basin No. 5, is south of the other two and is the smallest at just over 45,764 acres.

In sum, the company's Susitna exploration rights cover about 580,147 acres.

Cook Inlet Energy's president, JR Wilcox, proposed the third Susitna license with a letter dated April 29, 2011, to the Alaska Department of Natural Resources.

Holding the applicant's name confidential, the state solicited public comments on the proposal, and invited competing proposals.

State oil and gas Director Bill Barron issued the exploration license on March 27 after Cook Inlet Energy fulfilled certain conditions.

Terms included the company paying a one-time licensing fee of $1 per acre or partial acre, for a total of $45,765. The company made a work commitment of at least $250,000 over the five-year license period, and posted a $50,000 performance bond.

In its press release, Miller said that upon timely completion of the work commitment, Cook Inlet Energy will have the option to convert license acreage to oil and gas leases with a five-year term, a 12.5 percent royalty rate and a $3 per acre annual rental rate.

Cook Inlet Energy is producing oil and gas from a number of properties on the west side of Cook Inlet. The company operates the West McArthur River oil field and the Osprey offshore platform in the Redoubt Shoal field.

Altogether, Miller Energy says it now has nearly 700,000 state acres under lease or license.

"We elected to pursue the new license in the Susitna Basin based on its proximity to our existing acreage and the potential to leverage our onshore drilling program in this area," Boruff said. "We are currently evaluating the acreage and developing a work program."

Miller Energy is a small company, with the 1,000-plus barrels per day of Cook Inlet oil accounting for most of its production. Yet Miller's shares trade on the Big Board, the New York Stock Exchange.

Miller and Cook Inlet Energy executives have touted extensive drilling plans, with a new rig expected to start work soon atop the Osprey platform.

On April 12, Miller announced it had raised $10 million through the issuance of new redeemable preferred stock.

The cash will help meet the company's immediate capital expenditure needs, Boruff said. ●

Contact Wesley Loy at wloy@petroleumnews.com

GOVERNMENT

BLM schedules NPR-A meetings

The Bureau of Land Management said April 24 that it will hold meetings to take comments on the National Petroleum Reserve-Alaska draft integrated activity plan/environmental impact statement released March 30.

BLM said the draft IAP/EIS proposes several alternative future management strategies for the NPR-A and is the first plan to cover the entire NPR-A, including BLM-managed lands in the southwest portion of NPR-A not covered in previous plans.

Decisions to be made as part of the plan include oil and gas leasing availability; surface protections; Wild and Scenic River recommendations; and Special Area designations.

Public comments will be accepted through June 1 and may be submitted at meetings, in writing by mail, fax or hand delivery, and on the plan website at www.blm.gov/ak.

Meeting schedules

Meetings will be held:
May 14, Point Lay, Community Center*
May 15, Wainwright, Community Center*
May 16, Nuiqsut, Kisik Community Center*
May 17, Atqasuk, Community Center*
May 21, Barrow, Inupiat Heritage Center*
May 22, Anaktuvuk Pass, Community Center*
May 23, Fairbanks, Noel Wien Library
May 24, Anchorage, Campbell Creek Science Center

Meetings will begin with an open house at 6 p.m., followed by the meeting at 7 p.m.

Meetings marked with an asterisk will also serve as subsistence hearings pursuant to the Alaska National Interest Lands Conservation Act.

—PETROLEUM NEWS

● NATURAL GAS

Hawker offers to work with CRA on HB 9

Sponsors of in-state gas line bill testify to problems in Senate committee version; Olson cites concerns around SGDA, gravel use

By KRISTEN NELSON
Petroleum News

When he pulled the plug on his oil tax bill April 25, Alaska Gov. Sean Parnell asked the Senate to move on in-state gas line legislation. House Bill 9 has been in the Senate Community and Regional Affairs Committee since late March. The committee heard the bill April 5, with sponsor House Speaker Mike Chenault, R-Nikiski, introducing the bill, which he described as implementing legislation to allow the Alaska Gasline Development Corp., established by House Bill 369 in 2010, to get to an open season.

Tom Wright, staff to Chenault, said HB 9 sets the framework for AGDC to serve as the state's pipeline entity and allows it to move forward working on the in-state line described in HB 369, while also allowing AGDC to participate in the aligned North Slope to tidewater liquefied natural gas project which the North Slope producers and TransCanada are considering.

On April 13 the committee presented a substitute, described by Olson staffer David Scott as paring the bill down "to the bare minimums that AGDC needs to get to open season," and allowing AGDC to create a fund so they can spend the money the Legislature appropriated in 2011.

Chenault told the committee "what this CS does is basically gut AGDC's ability to move forward on an in-state gas pipeline project" by eliminating AGDC's ability to move forward with a pipeline and "requiring sanctioning by the Legislature through another law." He told Olson that the sponsors had not participated in drafting the CS.

On governor's call

HB 9 remained in Senate CRA through the end of the regular session and was included on the governor's April 16 call for a special session.

The committee heard the bill again April 19, hearing from bill co-sponsor, Rep. Mike Hawker, R-Anchorage.

Committee Chair Donny Olson, D-Golovin, said he wanted the gas pipeline to come back to the Legislature for sanctioning because of what happened under the Stranded Gas Development Act in the administration of Gov. Frank Murkowski.

Hawker told the committee that the SGDA was very different, allowing the administration to hold confidential negotiations which the Legislature would then have to approve. He said SGDA failed because of the way it was structured and because the gas market changed.

HB 9 took a different approach, Hawker said, that of creating and empowering a public corporation which would work "as openly as possible in the marketplace" under direction from the Legislature provided in the bill.

AHFC

AGDA is under the Alaska Housing Finance Corp. board of directors, which includes three state commissioners. Hawker said Alaska Housing Finance is an entity "that has worked well for all Alaskans and under all political regimes."

AHFC "is essentially the state's investment bank and we've created really a pipeline development group within" AHFC, he said, adding that HB 9 "struck a delicate balance" in that "AGDC is operating, as much as it can, as an open public corporation."

Unlike the SGDA, where the executive made a decision and the Legislature was asked to validate that decision, "it's us vesting our trust and confidence in an agency of the state to move forward with a project."

Hawker said the great concern with requiring the Legislature to sanction a project before it could move forward is "we're 60 legislators" with "provincial interests to represent," whereas AHFC is an agency with a "broader mission to serve all the state of Alaska, and we really believe that can serve to insulate proper economic best business practice management decisions from the inevitable politics of this building where we, by very definition, are obligated to be provincial and argue for the best of our individual districts."

Contract carriage

The CS also eliminated the provision of HB 9 that allows AGDC to offer contract transportation service, Hawker staffer Rena Delbridge told the committee, leaving the line operating as a common carrier. Like the issue of sanctioning by the Legislature, this would make it difficult for AGDC to secure commitments in an open season. AGDC needs to be able to provide firm transportation service, Delbridge said, noting that the state's contract with TransCanada under the Alaska Gasline Inducement Act allows contracts for firm transportation. She said AGDC has been advised by potential open season participants and by financiers that without firm contracts, "there may not be the necessary underpinnings to finance a pipeline."

Among other concerns that Olson expressed was over the routing of the line from the North Slope to Southcentral, especially with jack-up rigs drilling in Cook Inlet.

Hawker said that the bill's sponsors hope work in Cook Inlet is successful, but "we're not willing to bet our communities on" that success.

He said that recognizing the possibility of large Cook Inlet discoveries, the sponsors were prepared to bring forward an amendment to the legislation that if gas is found in Cook Inlet to meet long-term needs in Southcentral and in Fairbanks, "that AGDC would be directed then to specifically pursue a south-to-north line" to take some of that gas to Fairbanks. ●

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GOVERNMENT

Obama forms energy working group

The three federal agencies most closely involved in energy production announced a plan April 13 to work together to address unconventional shale gas and tight oil resources.

Through the program, the Department of Energy, Department of the Interior and the Environmental Protection Agency will identify research priorities for unconventional plays and work to eliminate redundancies as they sponsor research and scientific studies.

BARACK OBAMA

"Through a close collaboration across the government that reduces redundancy and streamlines our research, we are positioning the Obama Administration to best meet the critical need of increasing public understanding and public confidence of these critical technologies so that we can continue safe and responsible exploration and production for many decades to come," DOI Deputy Secretary David J. Hayes said in a statement.

The collaborative program followed an executive order from President Obama creating a federal working group to promote unconventional resources while assuring of environmental protection. "President Obama has created this interagency working group to ensure that these energy innovations happen safely and responsibly, without compromising the environment or the health of the American people," EPA Deputy Administrator Bob Perciasepe said in a statement. "We will continue to rely on the best available science to oversee the responsible development of these energy sources."

Several exploration and production companies are launching programs to explore the resources potential of three stacked shale formations on the North Slope of Alaska.

—ERIC LIDJI

● PIPELINES & DOWNSTREAM

BP plans to remove old Cook Inlet pipelines

By WESLEY LOY
For Petroleum News

BP Exploration (Alaska) Inc. this summer plans to remove abandoned pipeline segments from a beach on the Kenai Peninsula northeast of Nikiski.

The pipelines once belonged to Amoco, a company BP took over in 1998.

Each line is 10¾ inches in diameter, with one meant to carry oil and the other natural gas.

Installed in 1966, the lines run from the Anna offshore platform to what is now the XTO Energy delivery facility, located onshore some 19 miles to the south. The lines have been abandoned since 1987.

BP is not proposing to remove the full length of the pipelines. Rather, it intends to cut out sections running along a 3,000-foot stretch of shoreline between where the subsea pipelines make landfall and the XTO facility to the west.

The reason for the removal is seasonal beach erosion, which is partially exposing the below-grade pipelines, says a BP permit application now pending with the Alaska Department of Natural Resources.

The exposed pipes are susceptible to damage from ice scouring or human interaction, and "represent a potential physical nuisance to users of the beach," BP's application says.

The two lines, which have an enamel fiberglass wrap and an outer concrete jacket, appeared to be in good shape during site reconnaissance in 2011, BP says.

The exposed pipes are susceptible to damage from ice scouring or human interaction, and "represent a potential physical nuisance to users of the beach," BP's application says.

Aside from ridding the beach of a potential hazard, removal of the pipelines will clear the way for some work XTO plans to do on its two 8-inch lines running perpendicular off the beach, above the abandoned BP lines, to platforms A and C offshore.

In all, about 6,000 linear feet of steel pipe will be excavated and removed, amounting to a total weight of 435 tons, BP says. The company plans to cut the pipe into 20-foot lengths and dispose of them in either the local landfill if clean, or in a permitted landfill in the Lower 48 should the piping be deemed toxic.

BP plans to do the work from May to September, with a break in the middle to avoid disturbing commercial salmon fishermen with nearby setnet sites. Using heavy equipment, BP plans to work during low tides to unearth and remove the piping. The job will involve 12 to 15 workers on site.

A vac truck and oil spill response contractors will be available to deal with any residual oil, the BP application says. ●

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FINANCE & ECONOMY

Encana adds second Japanese partner

Encana has pulled off a second deal with a Japanese investor in as many months, selling a 32.5 percent interest in 5,500 existing and future coalbed methane wells in southern Alberta for C$602 million.

It's all part of the Canadian giant's strategy to develop partnerships to overcome the 10-year low in gas prices that Canada's National Energy Board forecasts will take another two years to make a significant recovery.

The joint venture with Toyota Tsusho covers 480,000 net acres of Encana's holdings of 2.1 million net acres in the Horseshoe Canyon dry gas fairway.

Encana, which will remain operator, said the deal recognizes the value of the lost-cost, low-risk asset and allows it to maintain an ongoing program to preserve capital.

Randy Ollenberger, an analyst with BMO Capital Markets, said it is clear the Japanese "are keen to replace a lot of nuclear power generating capacity, so they're pretty aggressive in terms of chasing down natural gas."

Toyota Tsusho said that unlike many CBM projects, Horseshoe Canyon coals do not produce water and can be developed without environmental concerns and costs related to dewatering the coals before production.

Brought on stream in 2001, the coals have current output of 120 million cubic feet per day from 4,000 wells and the potential to develop more than 1 trillion cubic feet.

Some 1,500 wells planned

Over the development period for the joint venture, about 1,500 wells are expected to be drilled and about 1,600 recompleted in order to raises production to 140 million cubic feet per day.

Andrew Potter, an analyst with CIBC World Markets, said in a note that Toyota Tsusho paid a premium price of C$3.86 per thousand cubic feet equivalent of proved plus probable reserves compared with his own firm`s 54 cents per thousand cubic feet equivalent for all of Encana`s proved plus probable reserves.

Randy Ollenberger, an analyst with BMO Capital Markets, said it is clear the Japanese "are keen to replace a lot of nuclear power generating capacity, so they're pretty aggressive in terms of chasing down natural gas."

"I think we`ll see more Japanese joint ventures or even direct acquisitions in the natural gas business in North America," he said, estimating Japan would have to secure 10 billion cubic feet per day of gas supply to meet its power generation needs.

In February, Encana negotiated a $2.9 billion deal with Japanese industrial conglomerate Mitsubishi for 40 percent of its undeveloped Cutbank Ridge property in northeastern British Columbia.

—GARY PARK

● NATURAL GAS

2000 to today: Alaska gas interest revives

Changing gas supply situation in Lower 48 sparks pipeline interest; Far East prices put liquefied natural gas back on the boards

By BILL WHITE

Researcher/writer for the Office of the Federal Coordinator

This is the concluding part of the third installment of this story. See the April 22 issue of Petroleum News for the beginning of "2000 to today."

Pipeline plans retreat

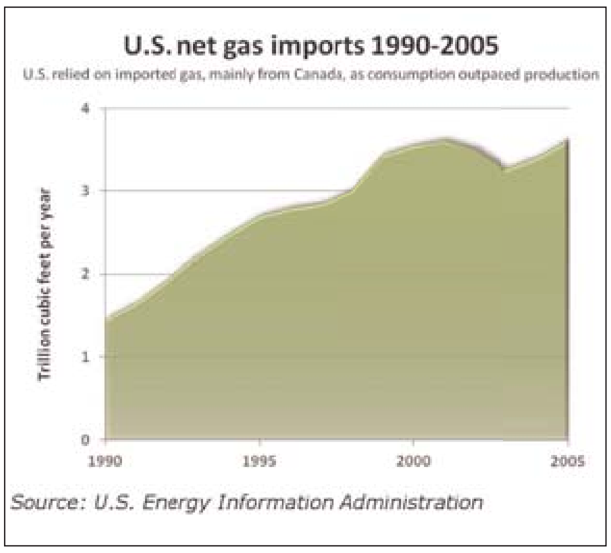
In mid-2001, natural gas prices were in a trough, a temporary one as it turned out.

The big three producers started sending signals that their enthusiasm was ebbing for an Alaska gas pipeline. Preliminary results of their joint study concluded a pipeline project might not be profitable enough to justify taking the huge risks involved, including the gas-price risk.

BILL WHITE

By 2002, Congress was actively looking for ways to help the project's economics, estimated by the producers in 2001 to cost almost $20 billion, six times more than the next most expensive North America gas pipeline. Among the options suggested was a federal tax subsidy to producers if gas prices dip below a given floor, repayable when prices break through a ceiling. That idea died but other ideas started to stick, many derived from the Alaska Natural Gas Transportation Act of 1976 that was custom-made to boost projects contemplated back then.

Finally, in 2004, Congress passed the Alaska Natural Gas Pipeline Act, which, like the 1976 law, streamlined government oversight and limited judicial challenges to a pipeline project. But it went further. The law authorized up to $18 billion in federal loan guarantees for a project to move Alaska gas to the Lower 48 (worth almost $22 billion today after adjusting for inflation), and it barred construction of an over-the-top pipeline. (The law also created the Office of the Federal Coordinator.)



OFFICE OF THE FEDERAL COORDINATOR

The Alaska Legislature was busy, too. In 2003 it revamped 1998's Stranded Gas Development Act to allow fiscal-term negotiations involving any pipeline project, not just an LNG project as the earlier law specified. The new law bore the same name. The constitutional issue of setting taxes by contract was still unresolved.

Soon, companies and others with gas pipeline ideas lined up to talk terms with the state.

State negotiating team fractures

As the state considered the applications to negotiate, it became clear an internal fight was under way in the administration of Gov. Frank Murkowski.

The schism would entangle state government for the next four years.

Some state executives believed reaching terms with the big three producers was key to securing a pipeline.

Others believed that limiting the producers' control of the pipeline would prompt more companies to explore for North Slope oil and gas. Already the prospects of a gas pipeline had lured new players. In May 2001, after the previous winter's gas-price spike, six companies acquired North Slope gas exploration leases — the first sold in decades. Anadarko was actively drilling for gas.

The stranded-gas applications stocked each side with ammunition. Their diverse approaches to a pipeline project included:

A pipeline-company project. TransCanada and Foothills Pipe Lines, two Canadian pipeline companies holding rights to the Alaska Highway project and route sanctioned in 1977, blew the dust off of their plans. TransCanada wanted the state to buy gas from the North Slope producers and market it. Later that idea morphed into both TransCanada and the state buying and marketing the gas.

Separately, MidAmerican Energy Holdings Co., a Lower 48 pipeline company, proposed a pipeline to Canada, provided it could get a five-year exclusive deal with the state that would force the producers to negotiate putting gas in the line. MidAmerican teamed with an Alaska Native corporation and an Anchorage startup headed by a former ARCO executive. But the state told MidAmerican it would not get an exclusive deal, and the pipeline company walked away in a public huff.

An LNG project. A trio of Alaska local governments — the Fairbanks North Star Borough, the city of Valdez and the North Slope Borough — formed the Alaska Gasline Port Authority in the late 1990s. Their proposal mutated over the years, but early on they proposed a pipeline and LNG plant at Valdez financed via low-interest debt the authority would issue. Low-cost debt would help the project economics. The LNG could go to Asia or the West Coast, wherever buyers could be found.

The Murkowski administration gave the port authority application an icy reception. Murkowski himself scoffed in 2006: "Would you invest in a project that had no gas, no financing, no contract for the sale of gas, no shipping com-

see GAS WARS page 11

continued from page 10

GAS WARS

mitments, no West Coast regasification facilities, no loan guarantee if exported, no Jones Act waivers (so foreign LNG tankers could be used) and no expertise in building a project of this size?"

Separately, in 2002 Alaska voters approved a ballot initiative pushed by LNG fans that created a state agency that could, among other things, buy North Slope gas, pipe it to Prince William Sound for export and finance the project with low-cost revenue bonds. The new agency, the Alaska Natural Gas Development Authority, never gained much momentum and governors downsized its mission over time, although it still exists.

A producer-sponsored project. The Murkowski administration worked hardest on this. Over three years negotiators hammered out key terms — a state equity ownership, gas taxes locked in for 35 years after pipeline startup, much higher oil taxes now but a lockdown on further oil-tax changes for 30 years.

Murkowski made it clear he believed a deal with producers was in Alaska's best interest. In fall 2005, dissenters within his gas team left their jobs — one fired and the rest resigning in protest. Besides objecting to a producer-owned pipeline, the dissenters believed the contract should have included a commitment to actually build the pipeline.

After much public griping about "Where is the deal?" Murkowski unveiled his proposed contract in spring 2006, with just months left in his gubernatorial term.

Much of the public panned the proposal. The sentiment was that the state got outnegotiated. That the deal came from a politically unpopular governor also made it hard to accept. State legislators never even voted on the contract, although they passed a significant oil-tax increase without the 30-year lockdown. The producers got smacked with the one piece of the deal they didn't really want but were willing to accept as part of the package. The Legislature just unwrapped the package.

Murkowski lost his re-election bid in the August 2006 Republican primary.

The new governor elected that November, Sarah Palin, was about to usher Alaska's gas pipeline efforts down a new path.

The Palin plan

Early in her 2006 campaign, Palin fell under the spell of Alaska's LNG boosters, and an LNG project became a central element of her platform.

But later in the campaign she backed off full support for LNG. After being sworn in, she hired all of the Murkowski administration dissenters who had left their jobs a year earlier. They helped guide the state's Palin-era approach to a gas pipeline project, an approach that continues today.

In May 2007, the Alaska Legislature passed Palin's Alaska Gasline Inducement Act. AGIA said the state would provide up to $500 million in pre-construction subsidies to a project whose sponsor agreed to certain "must haves." These included:

North Slope gas would be made available for Alaska use, though someone other than the project developer would need to move the gas from the big pipeline to consumers.

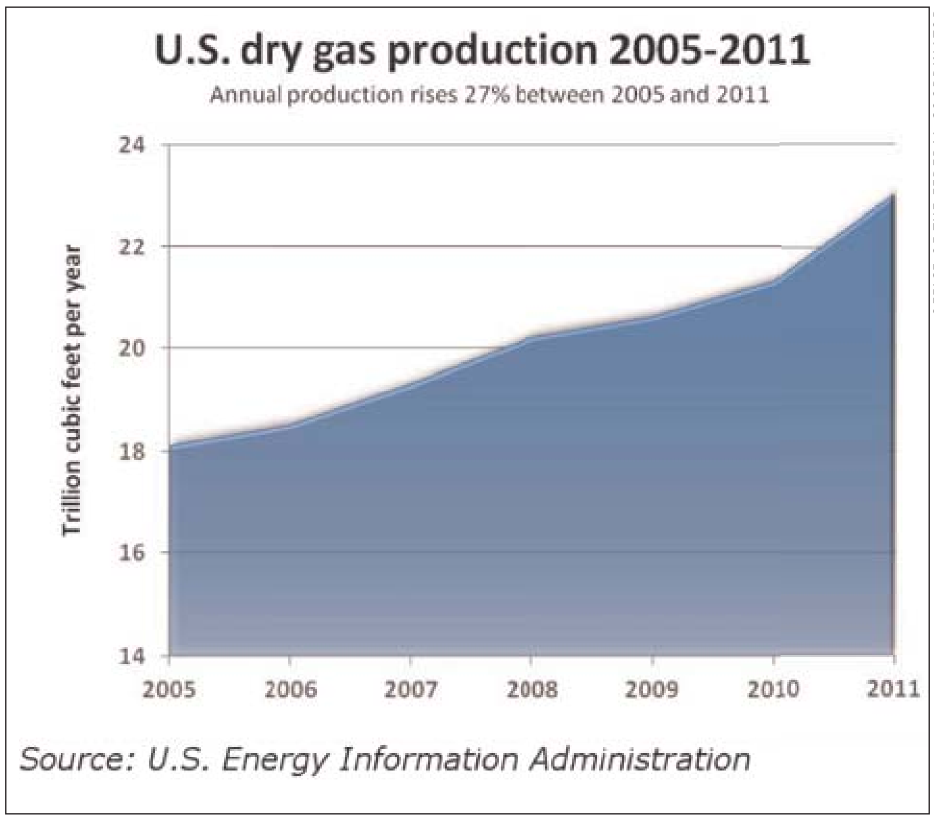
Certain actions to hold down the pipeline tariffs to encourage North Slope exploration and development.

Agreement to hire Alaskans and Alaska companies.

A firm timeline for project development, though no commitment to build the pipeline.

Agreement to expand the pipeline to accommodate future shippers, with all shippers contributing to the expansion cost.

And the biggie: A commitment to continue engineering and other work toward getting federal approval of a pipeline even if shippers fail to pledge enough gas during the initial open season to make the project viable. The state believed shippers eventually would sign up, and getting a federal certificate for a pipeline would keep the project moving forward while negotiations with shippers progressed.



OFFICE OF THE FEDERAL COORDINATOR

The big three North Slope producers slammed many of the AGIA terms. The deadlines were too inflexible, they said. They ignored economic reality. Where is the fiscal stability they need before committing gas to the line and promising to pay the tariff? Why should original shippers subsidize future shippers? Why continue working on the project if the open season fails?

BP and ConocoPhillips (Conoco and Phillips merged in 2002) announced a non-AGIA sanctioned gas pipeline venture called Denali – The Alaska Gas Pipeline in April 2008, 10 months after AGIA became law. They would look at building a $35 billion project down the Alaska Highway to Alberta, they said. But after a failed 2010 open season, they disbanded Denali in May 2011, citing "a lack of customer support." The companies spent $165 million on their effort.

The state awarded the AGIA license to TransCanada later in 2008, and ExxonMobil joined that effort the next year. This partnership — called the Alaska Pipeline Project — also held its open season in 2010. It offered two options: A $32 billion to $41 billion Alaska Highway pipeline to Alberta, or a $20 billion to $26 billion pipeline to Valdez, with other companies to bear the additional cost of an LNG plant and tankers.

TransCanada/ExxonMobil negotiated with bidders, but so far has failed to reach any shipper agreements. However, under terms of AGIA, the partners continue working toward the required October 2012 application to the Federal Energy Regulatory Commission despite the lack of pipeline customers. FERC has begun its extensive environmental review for the pipeline to Alberta. Assuming the commission accepts the TransCanada/ExxonMobil application as complete in October, FERC could issue a project certificate by fall 2014. The environmental review and FERC process is looking only at the Albert option; TransCanada/ExxonMobil didn't submit detailed route plans and data for the Valdez LNG project.

Meanwhile, as was true in the 1970s and again in 2001, the world of natural gas is in flux.

Fears of a Lower 48 natural gas shortage are gone. New supplies of shale gas are more than offsetting declines from aging conventional gas fields. Prices have sunk to late-1990s levels.

Over in Japan, the world's largest LNG market, prices are sky high. LNG prices there are linked to oil prices, which are soaring. Japan's disaster at its Fukushima nuclear power plant in 2011 boosted demand for LNG as a fuel at least temporarily, awarding LNG sellers a juicy price premium.

It's unclear if these developments are adding a new, permanent curve to the 40-year rollercoaster ride that describes the journey to realize an Alaska gas pipeline project. The big three North Slope producers said they might look again at LNG's potential even as TransCanada and ExxonMobil continue their state-aided pursuit of a FERC certificate for the pipeline to Alberta. ●

Editor's note: This is a reprint from the Office of the Federal Coordinator, Alaska Natural Gas Transportation Projects, online at www.arcticgas.gov/print/Interest-in-Alaska-gas-revives-2000-to-today.

● EXPLORATION & PRODUCTION

USGS revises world resource estimates

Publishes new assessment of remaining technically recoverable resources in possible undiscovered conventional oil and gas fields

By ALAN BAILEY
Petroleum News

In a report published April 18 the U.S. Geological Survey has provided a new assessment of worldwide undiscovered, technically recoverable oil and gas. The assessment does not include so-called unconventional resources such as shale oil and gas, and does not include data for the United States.

The agency has estimated remaining undiscovered resources from 171 worldwide geologic provinces to be 565 billion barrels of oil, 5,606 trillion cubic feet of natural gas and 167 billion barrels of natural gas liquids. No ranges of uncertainty are provided for these overall figures, although ranges provided for individual regions within the assessment indicate some significant geologic uncertainty relating to the data.

USGS says that it is conducting a separate study to assess undiscovered unconventional oil and gas.

"By placing this information in the public domain, government leaders, investors, public and private corporations, and citizens have a common information base for planning and decisions that affect the global environment and market place," said USGS Director Marcia McNutt when announcing the publication of the assessment.

The last USGS worldwide assessment, published in 2000, estimated undiscovered resources of 649 billion barrels of oil, 4,660 tcf of gas and 207 billion barrels of natural gas liquids in 128 geologic provinces.

Four regions

Just four regions account for 75 percent of the undiscovered oil, USGS says. These regions consist of South America and Caribbean with 126 billion barrels; sub-Saharan Africa with 115 billion barrels; the Middle East and North Africa with 111 billion barrels; and the Arctic provinces of North America with 61 billion barrels. All of the world's regions are likely to have significant undiscovered gas resources, USGS says.

Also of note in the overall results from the assessment are the combined regions of the Arctic Ocean and the former Soviet Union, with an estimated range of 16 billion to 117 billion barrels of oil, and a mean estimate of 66 billion barrels. This combined region has a potential range of 398 tcf to 4,056 tcf of natural gas, with a mean of 1,623 tcf, and a potential range of 10 billion to 97 billion barrels of natural gas liquids, with a mean of 8 billion barrels.

Also of note in the overall results from the assessment are the combined regions of the Arctic Ocean and the former Soviet Union, with an estimated range of 16 billion to 117 billion barrels of oil, and a mean estimate of 66 billion barrels.

North America, excluding the United States but including Mexico, Canada and several Arctic provinces, has a potential range of 26 billion to 208 billion barrels of oil, with a mean estimate of 83 billion barrels. This region has a range of 160 tcf to 1,510 tcf of natural gas, with a mean of 574 tcf, and 4 billion to 56 billion barrels of natural gas liquids, with a mean of 19 billion barrels.

By comparison, USGS has previous assessed a mean volume of 27 billion barrels of undiscovered, technically recoverable conventional oil onshore in the United States, while the Bureau of Ocean Energy Management has assessed a mean of 89 billion barrels of undiscovered conventional oil in the U.S. outer continental shelf. Those figures add to a total estimate of 116 billion barrels of undiscovered, recoverable, conventional oil for the entire United States.

The corresponding figures for U.S. conventional natural gas are 388 tcf onshore and 398 tcf on the outer continental shelf, leading to a U.S. total of 786 tcf.

Important to understand

Having just visited Brazil to promote strategic partnerships in energy development, Secretary of the Interior Ken Salazar commented on the importance to the United States of an understanding of worldwide resources. USGS thinks that nearly half of the undiscovered South American and Caribbean oil resource lie offshore Brazil.

"While we continue to focus our efforts on ways to continue to grow domestic energy production for America and further reduce our dependence on foreign oil, better knowledge of untapped resource potential all around the world will help us make better decisions regarding both domestic and global energy policy and resource management," Salazar said. "In particular, this assessment underscores the importance of continuing to strengthen our energy partnerships in the Western Hemisphere with nations like Brazil, where we are working closely with industry and government to share best practices on offshore drilling safety and to enhance the energy security of both our countries."

Methodology

The USGS assessment method involves using a geologic understanding of geologic provinces within each region to define petroleum systems within the provinces and hence identify assessment units — mapable volumes of rocks with common geologic traits. The USGS scientists assess possible ranges of oil and gas volumes within each assessment unit and then statistically combine the results to derive resource volumes for provinces and regions. In this new worldwide assessment the scientists defined 313 assessment units.

USGS says that it is conducting a separate study to assess undiscovered unconventional oil and gas. ●

Contact Alan Bailey at abailey@petroleumnews.com

● ENVIRONMENT & SAFETY

Study examines Cook Inlet marine mishaps

Oil tankers have 'lowest baseline spill rate' of vessels plying inlet, but they pose top spill risk, says citizens council report

By WESLEY LOY
For Petroleum News

The Cook Inlet Regional Citizens Advisory Council has released a new analysis of vessel accidents and spills as part of an ongoing maritime risk assessment project.

Not surprisingly, the study found that crude oil and petroleum product tankers pose the greatest risk in Cook Inlet.

"Tank ship risk is primarily attributed to their greater oil capacity and their concentrated operations in the middle region of the inlet. They also showed a high likelihood for a structural failure," concludes the study from contractor The Glosten Associates of Seattle.

The report, titled "Spill Baseline and Accident Causality Study," builds on a previous report examining Cook Inlet vessel traffic. The Cook Inlet RCAC released the vessel traffic study in February.

Hundreds of scenarios

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.

The Glosten study examines 16 years of data, from 1995 through 2010, on spills and the types of incidents leading to spills in Cook Inlet. During that period, 121 incidents occurred involving all sorts of vessels, from tankers to tugs to barges to offshore supply boats. Of these 121 incidents, 60 involved spills, the data show.

The study's authors analyze incident and spill rates according to vessel type and then forecast spill risk as far out as the year 2020.

They run hundreds of spill scenarios using a range of factors: vessel type, incident type, location in Cook Inlet, whether vessels are moving or moored, whether ice is present in the inlet, the type of oil aboard the vessels, and spill volume. The researchers also consider the positive effect of the shift to double hulls for tankers and tank barges.

Incident types include allision (one ship striking another), bilge discharge, collision, equipment failure, fire, drift grounding, powered grounding, operations error, structural failure or transfer error.

Low spill rate, high risk

"The workboat vessel type had the highest baseline spill rate: 0.96 spills per year," the study found. "Tank ships have the lowest baseline spill rate, but have the most risk from an oil spill in Cook Inlet."

The Cook Inlet vessel traffic study released in February tallied 480 ship port calls or transits during 2010, with 15 ships accounting for 80 percent of them. These ships regularly called at Homer, Nikiski or Anchorage, the state's largest city.

The 15 ships included five oil tankers — the Overseas Boston, the Overseas Martinez, the Overseas Nikiski, the Seabulk Pride and the Seabulk Arctic — operating between the Drift River oil terminal on the west side of Cook Inlet and the Nikiski community on the east side, home to the Tesoro refinery.

Find the spill baseline, accident causality report as well as the vessel traffic study at www.cookinletriskassessment.com. ●

Contact Wesley Loy at wloy@petroleumnews.com

FINANCE & ECONOMY

The Russians are here — almost

A landmark alliance by Rosneft and ExxonMobil that could involve spending of US$500 billion over the long term will give the Russian giant 30 percent stakes in Exxon-owned projects in North America — tight oil reserves in West Texas, 20 deepwater blocks in the Gulf of Mexico, and, overlooked in the initial announcement, exploiting shale oil in Alberta.

On the flip side, the partnership will also study the feasibility of developing 1.7 billion metric tons of tight oil in Western Siberia.

The Canadian stake involves the hot Cardium tight oil play in central Alberta, where Rosneft subsidiary RN Cardium will participate in the Harmattan acreage covering 56,000 acres and operated by Exxon affiliate, Imperial Oil.

An Imperial spokesman told the National Post that "generally speaking, all the North American assets that Rosneft has farmed in on … are designed to help them develop technologies for use in unconventional reservoirs in Russia."

"Western Siberia has a long-running conventional production area where they want to use unconventional resource development to capture what technically was not producible economically, similar to areas in North America where conventional production is depleting," he said.

The spokesman said Rosneft is primarily anxious to gain know-how in the use of hydraulic fracturing with directional drilling.

New tax treatment

Andrew Potter, an analyst with CIBC World Markets, said Rosneft's arrival in North America seems to have been facilitated by new tax treatment for Russian companies investing outside their domestic confines.

He said it could stimulate even greater competition for strategic assets in Canada, where a host of Asian companies have acquired interests in the oil sands and shale plays.

The test will be whether, this time around, the Russians carry through with their plans.

Previously, plodding and erratic decision-making saw the collapse of a deal between Gazprom and Petro-Canada to export LNG from Russia to a regasification terminal in Quebec and no progress at all on Gazprom's expressed desire to own infrastructure and exploration and development assets in Canada.

The Rosneft transaction will also test the outer limits of Canadian Prime Minister Stephen Harper's eagerness to open the doors to foreign investment in Canada's energy sector.

Gaining a stake in upstream development is one thing; gaining access to technology pioneered and developed in Canada might be seen as either problematic, or the price Canada must pay to diversify its oil and gas markets.

—GARY PARK

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PROPOSAL DROPPED

of Revenue Bryan Butcher and Deputy Commissioner Bruce Tangeman — were barely allowed to present the bill and even the Legislature's consultants, PFC Energy, came under fire.

While new oil and oil from legacy fields were split out in the governor's new bill, Senate Bill 3001, the dollar amount of the overall tax reduction in SB 3001 was within a couple of million dollars of that cut in HB 110.

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

Senators did not accept the administration's reasoning, and Senate Resources co-Chair Joe Paskvan, D-Fairbanks, wanted to know what experts the administration could bring to the table to defend its reasoning that tax reductions were needed on existing production.

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House Resources

The House has not had an oil tax bill to consider this year, and House Resources, meeting with House Energy, began at the beginning, meeting twice a day, and into the weekend the first week of the special session.

The House committees heard from PFC Energy, the consultants working with the Legislature on oil tax issues, beginning with some of the industry overview presentations the Senate heard during the regular session.

They also heard what the Senate heard from PFC Energy's Janak Mayer, that while cutting taxes across the board is the simplest way to incentivize investment, that method moves a lot of cash across the table unnecessarily, because a lot of the work the companies do in legacy fields is economic.

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

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

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

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STEDMAN Q&A

change the tax mechanism instead of just adjusting the rate?

Stedman: (Adjusting the rate) doesn't fix the internal problems with ACES. You can lower the rate of progressivity from 0.4 to some other number, but it's a broader question than that.

I'm hoping in the future that we'll look at getting the progressivity mechanism out of the net and onto the gross.

Petroleum News: Are you planning to introduce something?

Stedman: I think it's time the administration carries the oil bill through the process. There were a lot of comments made that the Senate was stalling, and it turns out there was no validity in that. When we actually sat down and engaged the concept of this bill, it didn't last 20 minutes.

I think there needs to be substantially more substance delivered into the legislative process if we're going to get a piece of legislation through here. It needs to address the complexities of the issue and move beyond the bumper stickers.

Petroleum News: The administration says the bill would reduce revenue by up to $1.4 billion a year, but you say $1.5 to $2 billion. Why the difference?

Stedman: Probably price variances. The current version moves a little bit less cash than the original HB 110, but not that much.

Petroleum News: SB 192 tried to cap tax credits for oil producers, but the governor's new proposal would expand well-lease expenditure credits. How will that get resolved?

Stedman: That's crazy. I'm not going to support it, I'll tell you that.

Excessive support through the credit mechanism is one of the problems we have with ACES. The exposure the state has under that is unacceptable. (According to PFC Energy), at about $120, which is roughly where we are today, it's 90 percent. It's ridiculous.

You need to deal with the credit side as you deal with the high tax burden, and adjust them both.

Petroleum News: What would you like to see happen this special session?

Stedman: A realization that ACES is dysfunctional at high oil prices and a willingness to stay here and fix it.

Petroleum News: How would you like to see it fixed?

Stedman: Well, I think you need to get down into the structural problems with ACES and fix them. You can't just move cash on the table.

Several areas can be addressed through some mechanism changes, such as taking the progressivity from the net and putting it up on the gross.

Petroleum News: How would that work?

Stedman: If you take the progressivity out of the net and put it on the gross, you're going to delink oil and gas and put less subsidy on the expense side. To a certain degree, industry might think that's a negative, but it would encourage them to control their costs more. It's a cleaner calculation, easier to do and understand.

It also allows us to put in place a mech-

see **STEDMAN Q&A** *page 15*

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STEDMAN Q&A

anism like the allowance (in Parnell's legislation), for targeted areas, if we want to target incremental oil, which I think we do.

Petroleum News: Do you think it's possible for this Legislature to agree on a tax bill?

Stedman: Not unless the administration comes to the table with some analysis and wants to participate in the policy discussion. If they want to participate just by moving cash, there's little to no chance we're going to get anything done. Particularly if they want to move $1.5 to $2 billion on the legacy fields, when we've had testimony from our consultants that it's not needed.

Petroleum News: Do you expect to be in Juneau the full 30 days?

Stedman: I don't know. I see less support for fixing the oil issue as the analysis rolls out.

The House did not engage our consultants last year in any meaningful way, other than Roger Marks on bracketing, and they basically threw a piece of legislation into the Senate without doing their due diligence. The more they get involved in the complexity of the issue and the more they understand our tax structure, the less likely it is that they're going to move this bill forward without huge structural changes to it.

Petroleum News: On another subject, do you see a way forward for HB 9, the in-state gas pipeline bill?

Stedman: I think we have a unique opportunity in front of us with the unfortunate circumstances in Japan taking down their nuclear plants. We have an open ocean between us, a short trade route, and a long-standing business relationship. I think we have a high probability of getting a large LNG export facility by the three majors if the state doesn't get in the middle of it and muck it up.

Petroleum News: And the best way to encourage that is to not pass HB 9?

Stedman: When we implemented AGIA (the Alaska Gasline Inducement Act), it was a kiss of death. That was a dysfunctional policy when it was hatched and didn't get any better as time went on.

Petroleum News: Anything else?

Stedman: It does concern me that if we don't get a solution to our tax structure at high oil prices, we're going to have a 2-4 year delay.

The other concern is that we need to get it right, versus just do something and then next year do something again. We need to give the industry as much stability as possible for their fiscal planning.

So you have to try to balance those two issues.

Petroleum News: But it sounds like you want the administration to take the lead.

Stedman: Correct.

Where are their consultants? When we did ACES and PPT, both the Legislature and the administration had consultants. If the departments can't handle the policy discussions, they need to get somebody in here that can.

April 26

Petroleum News: Were you surprised by the governor's announcement?

Stedman: Yes.

It was too early to call it quits. The House was just beginning to engage. I thought in roughly two weeks we'd be in a position where we could start having some discussions on what the final outcome would look like.

Petroleum News: Is it fair for Parnell to blame senators who "believe Alaska's oil production decline is a myth?"

Stedman: I don't think anybody in the Legislature believes that a production number (falling) from 2 million to 600,000 isn't true. But we're going through a natural decline curve, a natural decay of the superfields — Prudhoe Bay and Kuparuk — and it's been going on for 20 years.

Petroleum News: How's your relationship with the governor?

Stedman: Good, as far as I know. I get along fine with him.

I don't think we're that far apart. He has made comments that at $80 and below, he's comfortable with the tax structure. The Senate's comfortable with it at $100 and below. That's only a $20 difference. That's not irreconcilable.

North of $110, there's a lot of support for restructuring ACES, because it's looked on by many in the Legislature, including myself, as dysfunctional. You've got problems in the state subsidy over capital expenditures, and you've got problems with the split of profit between the industry and the state.

Petroleum News: What would you like to see happen now?

Stedman: I think we need to stay here and deal with the embedded problems with ACES. And just because the going gets a little rough — that's just par for the course. PPT and ACES got messy. Some people became very embedded in their opinions and some remained more flexible, but we worked through the situation in both cases and came up with a policy.

I think there's broad realization that at $130, $140, $150, we have problems in our tax structure. So let's fix them.

Petroleum News: You want the governor to introduce something new?

Stedman: I don't know about that. I think all parties need to remain flexible. You can't restructure our tax without the support of the executive branch.

Petroleum News: But technically, the governor would have to introduce it.

Stedman: If he called another special session, he'd have to introduce the legislation. If the Legislature called themselves back in, they would introduce it.

But I'm not going to introduce legislation in the Senate Finance Committee just to have (DOR) withdraw from policy discussions, because it's not just a big cash movement. The issue isn't let's move cash. The issue is let's fix ACES. And that will move the split of profit.

Petroleum News: Any additional thoughts on HB 9?

Stedman: No. I've got it on my desk. I have to start reading it this morning.

I was wrapped up in the oil and watching the House, and was pleased the House was starting to engage. It would have been nice to see what the Resources Committee came up with.

Petroleum News: A large-scale gas line would presumably take longer to develop. What do you say to people in Southcentral who need gas?

Stedman: Cook Inlet.

Petroleum News: And Fairbanks?

Stedman: Fairbanks is one of the communities in the tightest energy spot, and we need to try to help as much as we can. ●

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PIPELINES & DOWNSTREAM

Pipeline corrosion upgrade planned

The operator of the trans-Alaska pipeline system, or TAPS, is planning a significant anti-corrosion project near the line's northern end.

The project is slated for milepost 25 along the 800-mile oil pipeline.

Alyeska Pipeline Service Co., the Anchorage-based energy company consortium that runs the line, has applied to the State Pipeline Coordinator's Office for an amendment to the TAPS right-of-way lease.

The amendment would add four acres to accommodate construction and new equipment for the cathodic protection project.

Cathodic protection is a widely used industry method for preventing corrosion. It involves the use of "sacrificial anodes" and electrical current to reduce the corrosion rate of a metallic structure.

A recent public notice said Alyeska plans construction activity along the Dalton Highway and a TAPS access road.

"A gravel pad will be constructed adjacent to the access road and a generator module will be installed to support a cathodic protection system in the area," the notice said. Fuel for the generator will come from the nearby TAPS fuel gas line.

Alyeska spokeswoman Michelle Egan emailed Petroleum News some project background:

"All pipeline cathodic protection anode beds have a finite life. Anodes are sacrificial materials that deplete and require replacement after a period of time. The Cathodic Protection upgrade at MP 25 is a new cathodic protection anode bed being installed as part of our Cathodic Protection program to assure continuous supply of cathodic protection to protect the pipeline from external corrosion."

The project, Egan added, is not the result of a regulatory action or any particular corrosion problem at milepost 25.

"The installation is part of our program to replace or supplement existing anode beds before cathodic protection in a particular area is no longer effective," Egan wrote.

The cost to complete the project is expected to be under $5 million, she said.

—WESLEY LOY

ENVIRONMENT & SAFETY

A sponge for mopping up spilled oil?

According to a paper published recently in a Nature online report, researchers at Rice University and Penn State University have discovered a technology for developing a reusable sponge for mopping up oil spilled in water. The technology involves the addition of small amounts of boron to microscopic carbon tubes called nanotubes, to form spongy blocks that repel water but readily absorb oil.

In laboratory-scale tests the scientists have floated a sponge made from the material on water, to absorb motor oil floating on the water. After removal of the sponge from the water, the oil can be stored in the sponge, burned off, or expelled by squeezing the sponge. The sponge can be re-used repeatedly and has been shown to remain elastic after as many as 10,000 compressions, the researchers say.

Apparently the sponge can absorb more than 100 times its weight in oil.

"They're super low density, so the available volume is large," said Daniel Hashim, the lead author of the report. "That's why the uptake of oil can be so large."

The researchers found that the use of boron provided the key to connecting nanotubes into lattice-like blocks by inducing the nanotubes to bond at an atomic level to form a complex tangled network.

But can the resulting sponge-like material be scaled up for use in, for example, an offshore oil spill response?

The researchers say that they are investigating ways of making large sheets of the sponge, or welding smaller pieces of sponge together.

Other potential uses for the material include the manufacture of lightweight batteries, the construction of scaffolds for bone-tissue regeneration and perhaps the fabrication of polymers for aircraft and automobile construction, the researchers say.

—ALAN BAILEY

Petroleum news

Oil Patch Bits

Carlile driver receives workplace safety award

As reported by the American Red Cross of Alaska April 24, Zeke Davis, a truck driver for Carlile Transportation received the 2012 Real Heroes Breakfast Workplace Safety Award, sponsored by ConocoPhillips Alaska.

When Zeke Davis left Valdez one morning last January, it never crossed his mind that he would help save the lives of two young women along the way.

Davis was on a route he knew well, but on this drive, he came upon an unfamiliar and frightening discovery — a terrible automobile accident.

ZEKE DAVIS

Driver Janina Sanders had been ejected from the vehicle and sustained major injuries. Terra Phillips, 18, was not ejected but had severe whiplash and was emotionally unstable. Davis first put Phillips in his truck, called for help and grabbed blankets to cover Sanders with while she lay on the road in the minus 30 temperature. He did not move the girl, despite the frigid weather, and that decision, it was later discovered, had saved her life. Had Sanders been moved or exposed to warmer temperatures, she could have bled to death. Thanks to Davis, his calm action and wise decisions, both young women made it to medical attention in time.

CGGVeritas awarded Angola 4-D processing program

As reported on the Your Industry News website April 17, CGGVeritas said that, after negotiations with Total Exploration & Production Angola and Sonangol, it has been awarded a five-year contract for the 4-D seismic processing and imaging of annual and biennial monitor surveys planned to take place offshore Angola.

Over 6,000 km2 of seismic data from five of Total's deep offshore group of fields in Block 17, which is operated by Total in partnership with Statoil, BP and Esso, are expected to be processed over the contract's duration. The large program, including fast-track, base and monitor processing, will be shared between the CGGVeritas processing center in Luanda, which has served the Angolan E&P industry since 1999, and the CGGVeritas dedicated processing center for Total in Pau, France, which has been operating since 2002.

CGGVeritas has already gained considerable experience with this type of project, having successfully delivered 4-D processing and reservoir characterization services to Total in Angola Block 17 over the last decade. The Luanda center, with support and training from the dedicated processing center in Pau, will draw on this expertise to apply a robust, optimized 4-D processing and imaging workflow for each field so as to deliver

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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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FRACKING SECTOR

Brunswick and Nova Scotia border, has no commercial shale production, but has an estimated 130 trillion cubic feet of potential gas in place, according to the Canadian Society for Unconventional Resources.

A number of smaller companies are at various stages of gathering seismic data and conducting geochemical testing and are able to seek permission to stimulate conventional oil and gas wells, Angie Leonard, senior advisor in the Maritimes office of the Canadian Association of Petroleum Producers.

She said "a handful of fracking procedures have been done, mostly in the exploration phase."

Leonard said that although the industry is disappointed with the Nova Scotia delay it would sooner the government "get the regulations right rather than rush into anything.

"It would be good to know where the province stands with regard to hydraulic fracturing so that as companies continue with exploration they know what regulatory environment they are heading into if they do happen to make a commercial discovery," she said.

More study time needed

Nova Scotia Environment Minister Sterling Belliveau said his government, like Quebec and New York State, needs more time to study fracking methods and deal with public concerns over possible contamination of drinking water.

Energy Minister Charlie Parker said the review will take into consideration findings by the U.S. Environmental Protection Agency and Environment Canada, as well as the provincial and state jurisdictions.

Peter Hill, chairman of Elmworth Energy, a subsidiary of Triangle Petroleum, said in a statement he was "very disappointed" that his firm will lose two years of its 10-year lease in Nova Scotia.

"Nova Scotia has as much gas resource potential onshore as offshore and to lose two years or more of time is a sad loss for the economic development of the province," he said.

New Brunswick Natural Resources Minister Bruce Northrup extended Windsor Energy's exploration license to five years from three years, citing his government's desire to create jobs and reduce a budget deficit, despite heated opposition to fracking.

—GARY PARK

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SHALE OUTLOOK

With massive increases in production in North Dakota, Montana and Texas, for example, the official government data cannot keep abreast of what is happening, he said.

Surging production

Pugliaresi said that the Energy Policy Research Foundation has been monitoring four U.S. shale plays and predicts that, with increased production of 2 million barrels per day from these plays, by the end of 2013 no more light sweet crude oil will be imported into the Gulf of Mexico. It is reasonable to assume that North America as a whole can increase oil production by 500,000 barrels per day each year, he said.

Also taking into account new oil production from Brazil, within 10 to 15 years there will be no further need to import Middle Eastern oil into the Western Hemisphere, Pugliaresi said.

Yet as recently as 2008 the Energy Information Administration testified to Congress that, regardless of how much land was leased for oil and gas exploration or how actively people pursue new resources, the United States would need to import substantial new supplies of natural gas, he said.

And, anticipating a surge in gas imports, companies invested $30 billion in liquefied natural gas receiving facilities. But as U.S. domestic shale gas production flourishes, those import facilities are now operating at about eight percent capacity, Pugliaresi said.

Abundant sources

With oil and gas source rocks already being essential ingredients for conventional oil and gas production in the United States, source rocks with the potential for shale oil and gas development are abundant in the country. And the simple models used for government resource forecasts cannot nimbly adjust to paradigm shifting breakthroughs such as the emerging technologies for exploiting source rock shales, Pugliaresi said.

The rapidly evolving technology is causing the cost of finding new resources to drop and the estimates of resource recovery volumes to climb.

"There are source rocks everywhere. It's a manufacturing process. Nobody drills a dry hole anymore," Pugliaresi said. "The technology is moving very fast."

Petrochemicals

Moreover, the production of relatively low-cost ethane, for example, from shale plays will place the United States in a strong position in the global petrochemical industry, Pugliaresi said, adding that the United States is now becoming competitive with the Middle East in this arena and has the lowest petrochemical feedstock costs in the world.

> *"There are source rocks everywhere. It's a manufacturing process. Nobody drills a dry hole anymore."* **—Lou Pugliaresi, president, Energy Policy Research Foundation**

"The United States is the most competitive country for value-added processing in the petrochemical business," Pugliaresi said.

Shell is considering the construction of a very large U.S. ethylene cracker, with the states of Pennsylvania, West Virginia and Ohio vying to provide a venue for the project, he said.

And, although the United States is a net importer of petroleum, including imported crude oil, the country is a net exporter of refined petroleum products such as diesel and gasoline, with refineries on the Gulf Coast especially well placed to act as export platforms, Pugliaresi said.

Cultural shift

The shale oil and gas revolution is also causing a change in the culture of U.S. oil and gas production, with production migrating away from the Gulf of Mexico region. Shale gas production started in Texas and rapidly moved to Oklahoma, West Virginia, Virginia and Pennsylvania, eventually leading to shale oil production in North Dakota, Pugliaresi said.

He attributed the rapid migration of shale development technologies and ideas across these states to the relative ease and speed of land leasing and industrial development in regions with little federal land.

However, infrastructure development for the transportation of oil has become something of an issue, especially with the need to ship oil to coastal refineries. Pugliaresi commented that he views the Keystone XL pipeline debacle as particularly unfortunate, since that pipeline could assist with the transportation of U.S. oil as well as carrying oil from Canada.

Because of pipeline bottlenecks, 100-car trains are shipping some North Dakota oil at considerable expense to Louisiana, while choke points for oil shipment are depressing oil prices quite dramatically in some North Dakota locations, Pugliaresi said.

"We really have to fix this problem," he said.

Government regulation

Pugliaresi said that government regulation and permitting also need to keep up with the rapidly evolving oil and gas situation.

"This is happening so fast and so quick that the way we traditionally regulate and permit new projects in the U.S. is not going to work," he said.

For example, it will likely be necessary to export some U.S. oil into Canada or Mexico, to enable the appropriate combination of crude types to be delivered to Gulf of Mexico refineries. But at present companies are very unlikely to be able to obtain export permits, Pugliaresi said.

Asked about the prospects for a pipeline to export Alaska natural gas to the Lower 48 states, Pugliaresi said that it will likely be a long time before Lower 48 gas prices attain levels sufficient to support the transportation of gas from Alaska. However, the economics of exporting U.S. gas to the Pacific Rim are intriguing at present, he said.

When it comes to Alaska oil development, it is necessary to find a way to deal with oil price uncertainty and to align the interests of those with capital to invest with the interests of the state and the federal governments, Pugliaresi said.

Environmental questions

Criticized by a couple of people in the World Affairs Council audience for not including the cost of environmental factors such as global warming and ocean acidification in his analysis of expanding oil and gas production, Pugliaresi responded that it is necessary to carefully consider the trade-offs between the economic value of oil and gas development and the cost of any resulting environmental impacts.

The value of oil and gas production for a state such as Pennsylvania is very significant, and to make comparisons with alternatives such biofuel production it is necessary to assess the value and cost of these alternatives, he said, adding that any form of energy production has some environmental impact.

Pugliaresi had earlier commented on the relative economics of fossil fuels and renewable energies. A fairly recent world view that oil would become short in supply and high in price is being reversed, thus raising questions over the relatively high cost of technologies such as wind power, solar energy and electric cars: While the value-added processing of petroleum products can create new jobs and fuel economic growth, the development of goods whose value is less than their cost of production is problematic, he said.

—ALAN BAILEY

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OIL PATCH BITS

high-end quality with a significantly reduced turnaround time. This will provide Total Angola's reservoir management teams with the information required and sufficient time for evaluating results to meet field development requirements.

ASRC shareholder wins Boston Marathon wheelchair race

Arctic Slope Regional Corp. said April 23 that a fight to the finish paid off for former Alaskan and current shareholder Shirley Reilly, who edged out the defending champion on April 16 to win the Boston Marathon women's wheelchair race by just one second. It was Reilly's sixth time competing in the Boston Marathon and set a personal best time of 1:37:36. "We are so proud of Shirley," said Tara Sweeney, ASRC senior vice president of external affairs. "Her commitment to the sport has been an inspiration, and we just want to congratulate her."

Being born premature left Reilly paralyzed from the waist down, but that didn't stop her drive to compete. She graduated from high school in 2003 in Los Gatos, Calif., where she was a part of the school's track team. Reilly went on to become a member of the 2004, 2008 and 2012 U.S. Paralympic Teams, and credits her success in athletics to hard work, lots of practice and support from friends, family and teammates.

Reilly's mother Dora is from Barrow and the family visits relatives on the North Slope at least once a year. The 26-year old currently lives and trains in Tucson, Ariz.

Reilly won the 2012 Los Angeles Marathon in mid-May.

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

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CONOCO EARNINGS

Eagle Ford, Bakken and Permian resource plays.

For natural gas, ConocoPhillips produced 59 million cubic feet per day in Alaska in the first quarter, down 12 percent year over year. The company produced 1.5 billion cubic feet per day in the Lower 48, down slightly year over year and quarter over quarter.

ConocoPhillips said second quarter production would be down between 50,000 and 60,000 barrels of oil equivalent per day, companywide, because of maintenance work in Alaska, as well as in Australia, the United Kingdom and two projects in Canada.

When asked by Citigroup Inc. analyst Faisel Khan why the quarterly earnings for Alaska were higher than usual, Chief Financial Officer Jeff Sheets mentioned "a bit of a pricing lag on some of the crude" that can impact quarterly comparisons "in a rising market." On two occasions, Sheets pointed to the fiscal system in Alaska, specifically pointing out that Alaska has "a pretty progressive tax regime at the current price environments."

ConocoPhillips and other companies want the state to change its tax code.

Alaska price premium

While Lower 48 production is gaining on Alaska, Alaska remains the more profitable play for now, largely because of a major pricing disparity between the two regions.

Although ConocoPhillips produced only slightly lower liquids volumes and far higher natural gas volumes in the Lower 48 than in Alaska during the quarter, the company earned only $254 million from the Lower 48, compared to $616 million in Alaska.

That's because ConocoPhillips realized an average sales price of $112.20 per barrel for Alaska crude oil but only earned $76.40 per barrel for Lower 48 crude during the quarter.

Additionally, ConocoPhillips reported an average price of $4.68 per thousand cubic feet for Alaska natural gas compared to $2.65 per mcf for its Lower 48 volumes. While Alaska natural gas is traded on long-term contracts in a relatively tight market, Lower 48 prices are highly liquid and being kept down by a surplus of supply from shale plays.

In a sign of the times, ConocoPhillips did not post any sales from its liquefied natural gas export facility in Kenai, perhaps for the first time in the nearly 45-year history of the pioneering plant. ConocoPhillips announced plans in early 2011 to mothball the plant because it couldn't secure contracts overseas, but a series of unexpected events allowed the company to continue making shipments to Japan and China throughout the year.

During the quarter, ConocoPhillips also reported $9 million in exploration expenses and $135 million in depletion, depreciation and amortization expenses in Alaska.

Companywide $2.9B in earnings

Companywide, ConocoPhillips earned $2.9 billion during the quarter, down from $3 billion in the first quarter of last year. The company produced 1.64 million barrels of oil equivalent per day worldwide during the quarter, its last as an integrated company.

Going forward, ConocoPhillips will become one of the largest independent exploration and production companies in the world and Phillips 66 will become a downstream company managing refining and marketing, midstream and chemicals operations.

ConocoPhillips said the Arctic, particularly Greenland, the Chukchi Sea in Alaska and the Barents Sea in Norway would continue to remain a focus for the upstream player. ●

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PROJECT DECISIONS

He said there will be legally binding timetables on reviews to put an end to "duplicative, cumbersome and uncertain" environmental reviews that the government believes are putting at risk projects such as exports of oil sands crude and LNG.

Restricted participation

Oliver and Harper have previously identified environmentalists and First Nations as interest groups that have hamstrung regulatory hearings, notably for Enbridge's Northern Gateway project that faces 4,500 registered interveners.

The government now intends to restrict participation in those hearings to individuals and groups that are directly affected by projects.

As part of the "wide-ranging" legislative changes, Oliver said the government will also shift the final authority to approve or reject large pipeline proposals from the National Energy Board to the federal cabinet.

The board will continue to review pipelines that cross provincial boundaries, but the regulator will only be able to make recommendations, although the cabinet will not be allowed to alter conditions attached to the NEB's recommendation.

Because of a pipeline's potential impact on the environment and its importance to the economy, the ultimate authority should rest with elected politicians and not appointed officials, Oliver said.

Oliver said that once legislation passes the House of Commons, reviews will be confined to three federal departments and agencies, down from 40, and smaller projects will become the exclusive jurisdiction of provincial governments.

He said the "one project, one review" of major projects will cover pipelines longer than 25 miles, leaving others to the provinces.

Oliver said legislation will impose deadlines of 24 months for environmental reviews, 18 months for projects that come under the NEB, which issues export permits, and 12 months for "standard" assessments.

Northern Gateway included

The new rules will be backdated to include Enbridge's Northern Gateway proposal to export 525,000 barrels per day of oil sands crude to Asia and California and import 193,000 bpd of condensate.

Brenda Kenney, president of the Canadian Energy Pipeline Association, said the federal government is bringing the NEB's authority in line with other independent federal agencies.

She said that "to a large extent, this is cleaning up an historical artifact (dating back to 1959) that is, in itself, a bit quirky."

Joseph Doucet, interim dean of the University of Alberta business school, said the government is unlikely to override the NEB because of the public backlash it could face.

David Collyer, president of the Canadian Association of Petroleum Producers, said Oliver has addressed the "key areas of interest and concern that we've talked about" by offering "more clarity and predictability and process timelines (by) dealing with redundancy and overlap between jurisdictions."

He said there is no reason to believe that opponents of projects will be more inclined to use the courts rather than the regulatory regime to make their case.

"Decisions will still be made by independent regulators. There will be no particular impact on whether people choose to use the courts," Collyer said.

Enbridge spokesman Todd Nogier said that until more details are available his company does not know how the announcement will affect "processes that are already under way" with Northern Gateway, but Oliver's goal of focusing the regulatory phase "makes great sense."

Oliver said adapting the legislation to existing regulatory applications such as Northern Gateway "will take into account how long the review has lasted so far, how much of the scientific evidence has been completed and how many people have been heard."

Double-hulled tankers required

Ottawa will protect the environment by requiring that crude tankers operating in British Columbia waters are double-hulled, carry pilots and are subject to aerial surveillance, while the new rules will apply only to pipelines longer than 40 kilometers, leaving provincial governments to handle the rest, he said.

He said Ottawa will make "environmental protection more robust" by increasing annual audits of pipelines to six from three.

"A gamut of smaller projects that do not have any environmental impact that will not be subjected to a comprehensive environmental review will still be subjected to provincial and federal laws," Oliver said. "They're not getting a free pass."

Premier Brad Wall of Saskatchewan, Canada's second largest oil and gas producing province after Alberta, told a news conference that he and other premiers have been pressing Harper to streamline reviews to ensure prospective investors do not face unnecessary regulatory delays.

"We want to make sure we have a rigorous environmental assessment process," he said. "But we don't think that means we need two."

British Columbia Environment Minister Terry Lake embraced the government plan, saying his province will continue to play its role as a trustworthy steward of the environment.

Environmentalists object

But Matt Horne, of the Pembina Institute, an environmental think-tank, questioned the British Columbia government's ability to "offer the level of environmental protection we need through the assessment process."

"When you add up B.C's big push for mining, shale gas and liquefied natural gas development and no increase in the provincial budget for environmental assessment those concerns become even bigger," he said.

Barry Robinson, an attorney with Ecojustice, an environmental law group, said the regulatory decision on major pipelines is moving from science-based to political.

He expressed concern about the move to limit participants in hearings to those directly affected, adding "that's going to shut out way more people and environmental groups that have been traditionally involved." ●

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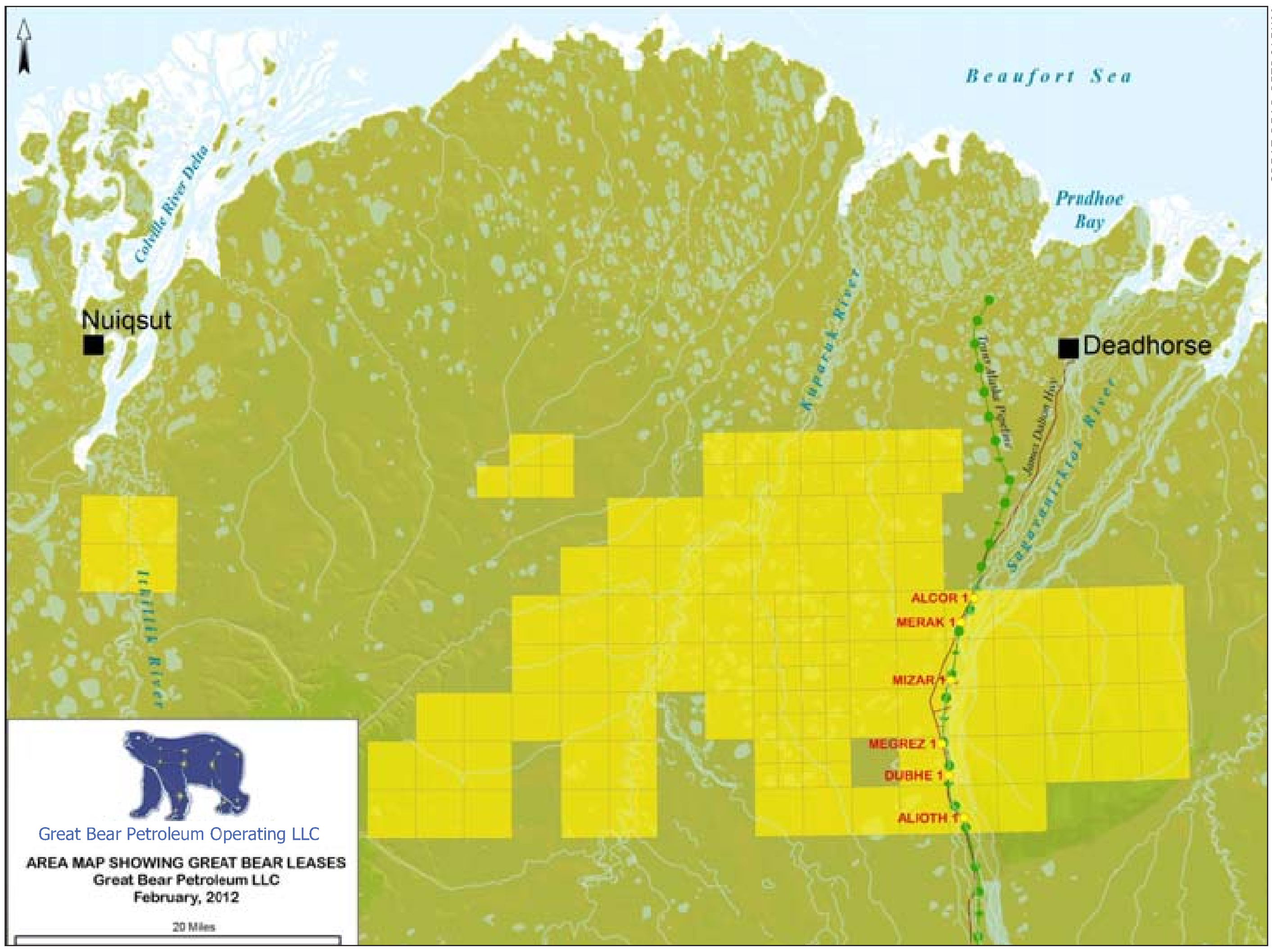
Duncan's focus, however, was on the progress his company was making on its proof of concept drilling and testing program, with drilling start-up just a little over a month away, and what the success of that eight-month program and the year-long pilot production program that is expected to follow, would mean to both the state of Alaska and his company.

Great Bear has permitted six gravel drilling pads in a transportation corridor on the eastern edge of its leases between the Dalton Highway, or Haul Road, and the trans-Alaska oil pipeline, where there are existing year-round roads and industrial activities with lots of pre-disturbed gravel — essential to being able to permit for year-round drilling.

"The ease of access off of the road was a fundamentally important part of our early strategy," Duncan said. "Recognizing that to prove the commerciality of an unconventional reservoir … we needed to be able to drill, complete and fracture stimulate these test wells. Three hundred and sixty-five day access was fundamentally important."

Once Great Bear moves west away from the corridor there are enough wetlands to change the lead permitting agency to the U.S. Corps of Engineers versus the state Department of Natural Resources, which is currently the lead. The issue of ice roads and pads will likely be raised, although once an oil field is proved, in-field gravel roads have been relatively easy to permit.



First well Alcor 1

The first well Great Bear and its farm-in partner Halliburton intend to drill is Alcor 1, from its northernmost pad (see map adjacent to this story), Duncan said.

Great Bear has most of its permits and authorizations in place to start drilling. It also has Nabors 105AC rig under contract as of May 15. Duncan said.

The only permits it appears to be missing are the drilling permits from the Alaska Oil and Gas Conservation Commission, which requires proof of bonding as a condition of the approval process, AOGCC Commissioner John Norman told Petroleum News April 25.

By state statute Norman could not say whether or not Great Bear had yet applied for its permits, which normally are the last permit applied for and take anywhere from a week to 30 days to obtain.

Working on plan for pilot production test

The company has some site work, including laying down rig mats, but otherwise Duncan said the six pads are ready to go.

"Our well plans have been designed, redesigned, improved, and refined. We believe that the technical work program we have today is as good as we could have hoped for," he said.

Most importantly, "we're under way. This is a very exciting time for the state of Alaska, Great Bear obviously, but for the state of Alaska because now we are about to test the commercial viability" of northern Alaska's source rock play.

If the company's proof of concept well testing is successful or encouraging, Duncan said it's Great Bear's "intention to move with considerable pace towards a pilot production test next year. That pilot production test will occur within this same corridor."

Great Bear executive and general counsel Karen Duncan, he said, heads up a team that is "working hard … to build the permitting basis for that pilot production test. That's a huge step for us. We're going to drill, frac and do short production tests on these wells, but the real proof … will be (if this) play produces oil into the pipeline for an extended period of time."

The pilot production test from a single gravel pad and using one or two mobile production modules will run for about a year, Duncan said.

CGG Veritas conducts 3-D seismic program

Another "big step" for Great Bear is represented on page 4 of Duncan's overheads, which shows a map "representing a proprietary 3-D program. It was acquired by CGG Veritas across the Great Bear acreage. This is a huge step for us. It's a huge step for the play. Three-D data will be fundamentally important to designing the orientation of laterals, helping us identify major fracture networks and faulting — it's fundamentally important to drilling these wells in the most efficient and timely manner. … A small programming fact … but a big step for us," he said, praising CGG Veritas for their work.

Drilling through December

Duncan next pointed to page 5 of his slides, "A Plan of Development."

The timeline, he noted, "is modified

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slightly from the early days, partly because of our own hand, and partly because of things imposed on us by external forces … permitting time, rig contracts, things of that nature. This is the pace that gets us — by 'us' I mean the whole room us, Great Bear, the state and everybody else that's going to be participating — to the point, in short order, that allows us to have a very earnest, open, honest and real discussion about commercial viability. … Beginning in a month, we're going to have more or less continuous drilling operations through the balance of the year. … We have a rig under contract from Nabors. And we intend to keep that rig busy, all the way past Christmas, ending sometime on or about the end of this year. (The Nabors rig is under contract to Repsol for next winter's North Slope exploration season, which generally starts in January and ends in mid-April.)

Coring three "world class" source rocks

Duncan said the proof of concept wells would involve "huge data gathering."

Co-chair of Senate Resources Committee, Fairbanks Sen. Joe Paskvan, asked Duncan to talk more about that, specifically the coring that would take cores from all three main source rocks.

"The North Slope basin — we have heard this from various sources, whether it's the state, whether it's me, whether it's other companies — the petroleum province is as prolific a province as exists in North America. Three world class, oil prone, source rocks exist regionally across the North Slope. This is not an assertion. It's a proven fact. They're drilled, they're sampled, they're analyzed; some of the best geochemists in the world have studied these rocks in great detail," Duncan said.

"Three zones exist across the entirety of our leasehold position, the shallowest of which is referred to as the HRZ, or GRZ in some publications. It's a lower Cretaceous age rock unit that has very high organic carbon content and, based on what we know from well results in the area and mapping and modeling work done by the USGS and Schlumberger, these rocks are mature for oil across the entirety of our leasehold."

In meters, Duncan said, the HRZ, "the first source rock that we'll encounter, will occur at about 2,500 meters (approximately 7,500 feet) below ground level. … We expect the section to be somewhere between 400 and 600 feet thick in total."

Great Bear will not core all of that, he said. "We'll selectively core, but it's a very, very thick interval of oil prone source rock.

All Alpine oil from Kingak

The next interval down is the Kingak, a Jurassic age shale, Duncan said.

"Again a prolific source rock; not recognized for its regional prevalence until the Alpine field was discovered. Virtually 100 percent of the oil in the Alpine field was sourced from the basal Kingak," he said.

"Sitting immediately beneath the Kingak is the Shublik, which is a Triassic age rock. The Shublik is the primary oil source rock for the North Slope. It occurs regionally in outcrop from the Brooks Range to nearly the Canadian border, all the way across through the central Brooks Range. … The Shublik is responsible for probably 60 percent-plus of the oil reserves known to exist on the North Slope of Alaska. Incredibly prolific rock. Very rich organic carbon content and importantly mineralogically, it's a carbonate. It's a black limestone. (Not shale.) That's important from a rock mechanics perspective because it's more brittle — we believe it to be more brittle. It certainly fractures well in outcrop. In fact, we have data from approximately 20 tests of naturally fractured Shublik in the Prudhoe/Kuparuk field area ... not unconventional-styled production where you require fracture stimulation in order to get it to flow."

Duncan said "cumulatively" with all three co-located source rocks "we're looking at a section that is six to eight hundred feet thick."

Great Bear's initial work program is going to focus heavily on "stimulating the Shublik, but we'll be collecting data in these proof of concept wells in the HRZ and the Kingak and looking at their mechanical properties in detail to ascertain whether we can actually produce those as well," he said.

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Beyond game-changing?

When asked, "How thick is the Shublik formation?" Duncan said, it "ranges in thickness, ranging to the northeast in our project area, from about 100 feet thick in the northeast to an excess of 250 feet thick as you go southwest across our leasehold."

When asked, "What if these rocks won't frac, or these rocks won't flow, it's just not going to work — if that's the downside, what's the upside? How far up could this go?" Duncan replied, "The downside well described. The upside is an air ball. Well outside the range of my expected outcomes but nevertheless this is mother earth. … If all three zones will frac and flow, ah, then the ultimate volumetric outcome … I haven't calculated, but it's beyond game-changing."

See part 2 in next week's edition of Petroleum News. ●

—Kay Cashman and Marti Reeve contributed to this report.

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Great Bear hires Galvin

PAT GALVIN

In his April 25 testimony to the Senate Resources Committee in Juneau, Great Bear Petroleum Operating LLC President and CEO Ed Duncan said he had hired attorney Patrick Galvin.

The former commissioner of the Alaska Department of Revenue, and more recently with the law firm K&L Gates, Galvin has been representing Great Bear Petroleum on a number of matters, including regulatory affairs and problem solving, Duncan said.

Galvin's title will be vice president of external affairs and deputy general counsel. His role, Duncan said, would include government and external affairs as the company expands its drilling west from the Haul Road (Dalton Highway).

—KAY CASHMAN