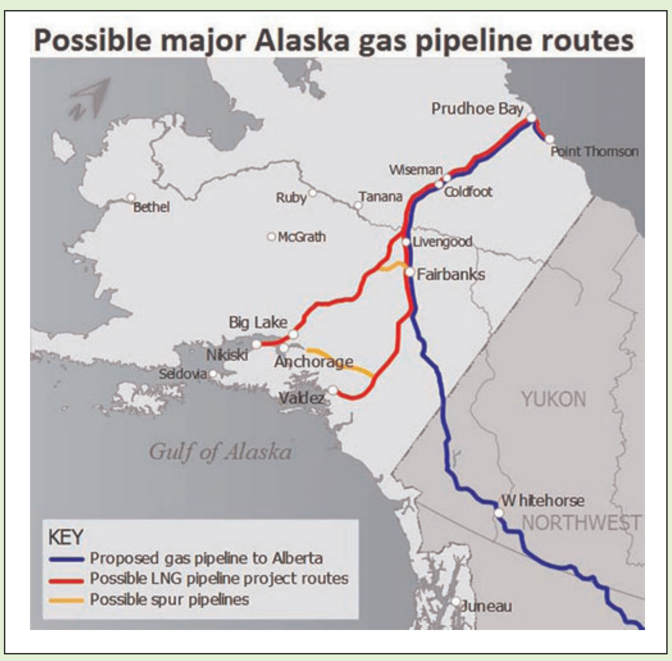
Petroleum news

Vol. 17, No. 20 • www.PetroleumNews.com | A weekly oil & gas newspaper based in Anchorage, Alaska | Week of May 13, 2012 • $2

page 3 Parnell looks back at tax debates, defends oil plan, promotes LNG

Challenge of distribution



OFFICE OF THE FEDERAL COORDINATOR

A gas pipeline from the North Slope would provide natural gas to Alaskans, but getting it to Fairbanks in Interior Alaska off of a main line, and then distributing it throughout the city could cost as much as a billion dollars. See story on page 16.

NordAq plans two wells at Tiger Eye on west side of Cook Inlet

NordAq Energy Inc., the small independent that has been quietly pursuing a program of oil and gas exploration in Alaska's Cook Inlet basin for the past couple of years or so, says that it now plans to drill two exploration wells in its Tiger Eye prospects onshore the west side of the inlet. The well locations are between two and three miles inland, to the immediate north of West Foreland.

Directional drilling will be required at each location, with the North pad well involving extended reach drilling and requiring a drilling rig that is suitable for that type of drilling operation.

In October NordAq filed a plan of operations with the Division of Oil and Gas for the drilling of the Tiger Eye North well. The company has since changed its plans, adding a second well, the Tiger Eye Central well, to its Tiger Eye project,

see **NORDAQ WELLS** page 22

Imperial, Exxon eye LNG for BC Horn River shale gas development

Imperial Oil and ExxonMobil Canada, the Canadian surrogates of ExxonMobil, are taking baby steps towards exporting LNG from their stranded natural gas reserves in British Columbia.

Their key joint holding covers 340,000 acres of shale gas properties in the Horn River basin of northeastern British Columbia where the two companies are working on a pilot production venture to get a better grip on the cost of development, while at the same time examining a potential LNG facility, Imperial Chief Executive Officer Bruce March told reporters at the company's annual meeting.

"Long term, it is a good proposition," he said, rating as "critical" the development of an LNG export industry to advance development of Horn River.

But he conceded Imperial's plans are less advanced than other British Columbia gas producers.

March said the joint venture has drilled 30 to 35 wells at Horn River which have yielded only methane.

see **HORN RIVER** page 24

EXPLORATION & PRODUCTION

Pioneer touts Nuna

A 50 million barrel discovery south of Ooguruk; Ivishak test a bust

By ERIC LIDJI

For Petroleum News

Pioneer Natural Resources Alaska Inc. is announcing a 50 million barrel discovery at its budding Nuna development based on exploration drilling completed this past winter.

The Nuna No. 1 well tested at an initial production rate of 2,000 barrels of oil per day, the Texas-based independent said during a first quarter conference call on May 3. Pioneer suspended the onshore well at the end of the exploration season, but expects to conduct a longer test next winter in addition to drilling an additional appraisal well at the prospect.

Pioneer also announced the results from two other wells drilled this winter, a successful development well into the Nuiqsut formation and an unsuccessful test of the Ivishak.

JUDY PATRICK

TIM DOVE

Altogether, the encouraging results could make Ooguruk more attractive for Pioneer after a more than a year of declining production from its flagship asset in Alaska.

Nuna No. 1 tested the southern extent of the Torok formation, the third and shallowest producing formation at the nearshore Ooguruk unit in Beaufort Sea, and it proved to be "one of the best wells we drilled in the Torok," according to Pioneer Chief Operating Officer Tim Dove. Although Pioneer primarily

see **NUNA DISCOVERY** page 22

EXPLORATION & PRODUCTION

Oil, gas from old assets

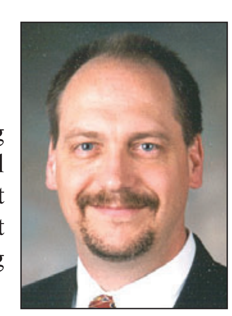
Independent Hilcorp reworking Cook Inlet wells, fields, formerly held by Chevron

By KRISTEN NELSON

Petroleum News

Hilcorp Alaska is focused on finding and producing more oil and natural gas from legacy Cook Inlet assets. It acquired Chevron's Cook Inlet assets last year and is in the process of acquiring Marathon Oil's inlet assets.

Producing from old wells and fields is the company's strength, John Barnes, Hilcorp's senior vice president for Alaska, told the Regulatory Commission of Alaska May 9 and the Alaska Support Industry Alliance May 10; this story combines comments from both presentations. Barnes said there are lots of opportunities in Cook Inlet, and Hilcorp is a fast-moving independent with enough financial clout to do the work that needs to be done.



JOHN BARNES

Among the challenges Hilcorp is working on, he said, are predictable permitting timelines — with predictability the real issue, not how long it takes.

"If it takes a year, you'd better have an inventory that lets you plan out a year ahead of time; if it's a week, that's great," Barnes said.

He said the biggest obstacle he sees is caused by the decline of the service industry in the inlet.

Hilcorp "can't move fast enough because we

see **HILCORP** page 23

FINANCE & ECONOMY

China ready to wait

Some C$20B invested in Canada; investment could grow 10-fold over 10-15 years

By GARY PARK

For Petroleum News

China's stable of state-owned energy companies has invested about C$20 billion in Canada's oil sands and shale gas assets — proof positive that Beijing is ready to ride out a stormy passage for pipelines from Alberta, across British Columbia to ship production across the Pacific, says Zhang Junsai, China's ambassador to Canada.

The delays in approving the key infrastructure elements will not deter China from seeking a key role in the development of those resources, he told reporters in Calgary.

Typifying the Chinese reputation for taking a long-range view of its investments, he said China has access to ample imports of oil and natural gas from Australia, Qatar and Russia, so, if necessary, supplies from Canada can wait.

"World economic power and wealth are shifting in a way that is historic and we as Canadians must decide that we will be on the right side of that history."
—Canadian Prime Minister Stephen Harper

"There`s investment opportunity because Canada is open for international investment," Zhang said.

"If there's opportunity, Chinese companies will

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● GOVERNMENT

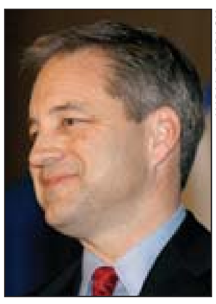
Parnell defends tax plan, promotes LNG

Governor calls criticism that administration wasn't prepared 'nonsense'; sticks with AGIA requirements ahead of gas line negotiations

By STEFAN MILKOWSKI
For Petroleum News

For Gov. Sean Parnell, simple economics dictate that lower oil production taxes will make more North Slope projects profitable. It's also clear that declining oil production is not okay, putting at risk thousands of direct and indirect jobs.

Parnell has made tax reform a top priority but has struggled to win legislative support for his proposals. After his HB 110 died this year in the Senate, he called lawmakers into special session to consider a new proposal. He surprised many when he pulled the bill from consideration on April 25, blaming the Senate for intransigence.


JUDY PATRICK
GOV. SEAN PARNELL

In an interview May 9, Parnell outlined the next steps to getting a gas line, defended his approach to tax reform, and discussed the Point Thomson settlement.

Petroleum News: Let's start with gas. This winter you encouraged North Slope producers to get behind an LNG export line, and on May 2, your administration gave TransCanada permission to focus on that project instead of an overland route through Canada. Why is that a better project?

Parnell: I actually led the charge last October when I announced that I wanted to see the producers, TransCanada, and all parties focus on a line from the North Slope through Alaska to tidewater. It was clear that the Lower 48 market had shifted to shale gas — the large volumes there had depressed the price. And the tsunami in Japan and the Japanese shift from nuclear power clearly created another reason to move to an LNG export scenario.

I then began calling on, working with, cajoling the CEOs of the producer companies towards alignment and towards resolution of Point Thomson, because each of those was necessary to get a large-diameter gas line approved and constructed.

Petroleum News: Will you require that an APP (Alaska Pipeline Project) and producer pipeline adhere to the "must-haves" in the Alaska Gasline Inducement Act?

Parnell: In my state of the state address, I called for alignment of the producers and TransCanada by the end of March, and that occurred. I called for resolution of the Point Thomson settlement among working interest owners, and that has occurred.

The reason I said I wanted the alignment "under an AGIA framework" is because of the benefits the Alaska Gasline Inducement Act provides Alaskans. It assures offtakes for Alaskan communities. It assures that Alaskan lands will be fully explored for gas because the pipeline will be accessible to future explorers. It assures that Alaskans will pay a distance-sensitive tariff on the gas they receive.

So I believe it has significant benefits within its framework, and I would much prefer to start any negotiation over fiscal terms with those benefits in place for Alaskans, instead of starting from scratch.

Petroleum News: Will you stick to all of the must-haves, or are some of them negotiable?

Parnell: Obviously some of them will need to be negotiable. But again, we're starting from a position of strength, where Alaska's must-haves are already clearly defined by law.

Petroleum News: When do you plan to address fiscal terms?

Parnell: The next benchmark for these companies to achieve is a project concept selection of an LNG project, which, under the benchmarks I set in my state of the state address, should occur in September of this year.

If that occurs, if the companies' hardening of their numbers and their alignment of interests come together around this LNG project, then fiscals will be the next step. Assuming all the benchmarks were met, I had offered to take those up during the legislative session of 2013.

Petroleum News: Why did you also support HB 9, which was aimed at jumpstarting a competing, in-state line?

Parnell: In every commercial negotiation, it's in a party's interest to have an alternative. When the producers, between 2001 and 2003, were negotiating with TransCanada over a "bullet line" from Alberta to Chicago, the producers were promoting their own line as an alternative.

I don't want Alaska to be dependent upon the producers' goodwill. Having an alternative, in this case the Alaska Gasline Development Corporation alternative, is very important to getting the best deal for Alaskans when it comes to a large-scale pipeline.

Petroleum News: So what's the next step?

Parnell: The next step is for the producers and TransCanada to get together with the Alaska Gasline Development Corporation to determine whether there is interest and value in merging, combining those efforts. The other benchmark that needs to be met by third quarter 2012 is for the producers and TransCanada to harden their numbers and finish their project concept selection stage of an LNG project.

Q AND A

Petroleum News: Moving to oil taxes, why did you decide to introduce a new bill for the special session?

Parnell: The new bill was merely a continuation of the two-year discussion we've been having. It reflected the methodology used by the Senate in passing tax credits for new fields. The bill I introduced used the Senate's methodology to incentivize not only new fields but also new oil from existing fields.

I made the mistake of thinking senators would be consistent in applying the same rationale to trying to extract new oil from existing fields as they had used to incentivize development at new fields.

Petroleum News: Why did you remove the proposal from consideration?

Parnell: I removed the proposal from consideration because it was clear that there were a few senators in controlling positions who think status quo decline is fine, who think the existing tax structure is fine. These senators don't have a plan for altering our production decline, but they were extremely critical and had hardened their positions against any notion of applying lower taxes to existing fields.

My view is very clear, that both existing fields and new fields have new oil that will not otherwise be produced without a tax change. That's simple economics. And to think that an oil company will extract 100 percent of the oil in a field anyway is not based on fact.

Petroleum News: Sen. Joe Paskvan, one of the Resource Committee co-chairs, requested that Gaffney Cline (a consultant to the administration) testify. Why were they not made available?

Parnell: Our work relied on Gaffney Cline. The Legislature had their consultants in PFC Energy. The issue was that

see **PARNELL Q&A** page 21

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Amy Spittler	MARKETING CONSULTANT
Dee Cashman	CIRCULATION REPRESENTATIVE

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

NEWS
907.522.9469
publisher@petroleumnews.com

CIRCULATION
907.522.9469
circulation@petroleumnews.com

ADVERTISING
Susan Crane • 907.770.5592
scrane@petroleumnews.com

Bonnie Yonker • 425.483.9705
byonker@petroleumnews.com

FAX FOR ALL DEPARTMENTS
907.522.9583

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● NATURAL GAS

TransCanada terminates 1st open season

2010 initial open season ended with bids from 'major industry players;' company says producers not ready to make commitments

By KRISTEN NELSON
Petroleum News

TransCanada Alaska filed a notice with the Federal Energy Regulatory Commission May 3 terminating its first binding open season.

The open season for the Alaska Pipeline Project, APP, began April 30, 2010, and ended July 30, 2010.

APP is the project licensed to TransCanada in late 2008 by the State of Alaska under the Alaska Gasline Inducement Act, or AGIA. ExxonMobil joined TransCanada in APP in mid-2009.

"During the open season, producers expressed significant interest in the Alberta Project in the form of conditioned bids for capacity on that pipeline," TransCanada told FERC. The company said there were "concerted negotiations for many months" between APP and the Alaska North Slope producers, but despite "good faith efforts" by all parties to the negotiations, no precedent agreements — binding commitments to "ship or pay" on the line — were signed.

TransCanada said it is APP's "assessment that the producers are not prepared to make commercial commitments to the Alberta Project at this time," and it is withdrawing the transportation service offerings in the 2010 open season notice.

APP is working with the ANS producers on the feasibility of a project including a pipeline to a liquefied natural gas facility at tidewater in Southcentral Alaska, TransCanada said.

If those evaluations lead to a project that appears commercially viable, or if there is renewed interest in taking gas to Alberta, TransCanada said APP would initiate a new open season.

Amendments to the plan in the AGIA license approved by the state May 2 call for initial work on an LNG project to be completed by September with an open season by the end of the year.

Multiple bids

After the initial open season closed in 2010, Tony Palmer, vice president of Alaska development for TransCanada, said that while results of the open season were confidential, "The Alaska Pipeline Project can report that we have received multiple bids from major industry players and others for significant volumes."

Confidentiality agreements between customers and the pipeline company prevented description of the open season results in any detail, Palmer said at the time. He said the confidentiality agreements "exist because the gas business is so competitive," with gas from Alaska competing with gas supplies coming into North American or international markets.

At the time of the APP open season there was also a competitive pipeline project, the BP-ConocoPhillips Denali project, with an open season which continued two months beyond that for APP, although Denali is no longer a factor. It was discontinued in May 2011 and the company said in a statement that its open season efforts had not resulted in customer commitments necessary to continue work.

Amendments to the plan in the AGIA license approved by the state May 2 call for initial work on an LNG project to be completed by September with an open season by the end of the year.

Typically open seasons for pipelines are confidential, but FERC has special requirements for an Alaska gas pipeline project because the remoteness of the North Slope and the expense of the project preclude competitive pipelines from being built.

The APP open season accepted bids for both the Alberta line and for a line to Valdez for LNG export. While Palmer did not comment in 2010 on which proposal received bids, TransCanada's statements to FERC would seem to indicate that only the Alberta project received bids, or that if there were bids for an LNG project, that negotiations over those bids hadn't been ongoing.

Alignment

Alaska Gov. Sean Parnell has been encouraging participation by all North Slope producers in an LNG project since last fall and at the end of March the three North Slope majors — BP, ConocoPhillips and ExxonMobil — said they had reached an agreement to work with TransCanada, under an AGIA framework, to evaluate a line to Southcentral for LNG export.

The companies told Parnell in a March 30 letter that they were making progress on "the next generation of North Slope resource development." That commitment, released in conjunction with a settlement of the long-standing Point Thomson litigation between the owners of that unit and the state, was directed toward natural gas development.

The companies said that "under the right business climate, the full commercial potential of this world-class resource can be unlocked." Point Thomson contains about a quarter of known natural gas resources on the North Slope (at 8 trillion cubic feet the largest accumulation next to Prudhoe Bay's 24.5 tcf.)

The Alaska Gas Pipeline Project Office said May 2 that Natural Resources Commissioner Dan Sullivan and Revenue Commissioner Bryan Butcher had approved a project plan amendment for the Alaska Pipeline Project under AGIA, allowing a shift of focus to LNG.

The governor has said that if benchmarks are met, the Legislature would address gas taxes next year. ●

Contact Kristen Nelson at knelson@petroleumnews.com

● GOVERNMENT

Murkowski endorses NOAA relocation

Alaska senator says Obama's proposal to move agency from Commerce Department to Interior 'makes sense on a number of levels'

By WESLEY LOY
For Petroleum News

Alaska Sen. Lisa Murkowski says she sees "real merit" in the Obama administration's proposal to move the National Oceanic and Atmospheric Administration from the Commerce Department into the Interior Department.

Murkowski, a Republican, explained her view on the matter in a recent op-ed column published in Alaska media outlets.

The Obama administration on Jan. 13 proposed the NOAA move as one prong of a reorganization plan meant to make the government more efficient and helpful to business with less duplication.

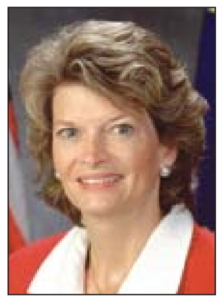
Formed in 1970, NOAA is an agency of considerable importance to the offshore oil and gas industry. NOAA conducts extensive scientific research, and is home to subagencies such as the National Marine Fisheries Service, the National Weather Service and the National Ocean Service.

'Fish out of water'

"There are many issues on which I disagree with President Obama," Murkowski began her op-ed column. "When someone is right on something, however, it is important to give credit where it's due."

The senator said that after reviewing Obama's plan for NOAA, she had concluded it "makes sense on a number of levels."

"From a basic structural perspective, NOAA is increasingly out of place at Commerce — like a fish out of water," she wrote. "Its stated mission is to provide the scientific data necessary to protect lives and property, as well as to conserve and help manage our nation's fisheries, oceans and coastlines. Now consider the two departments it could be located in. Commerce is primarily focused on the promotion of economic growth and international trade, dealing with patents and other commercial issues. Interior, meanwhile, manages natural resources, public lands, and fish and wildlife. Based on that alone, it's easy to see why Interior is a more natural fit."


SEN. LISA MURKOWSKI

She noted the story of how NOAA was placed where it is today: Because President Nixon "was upset with one of Alaska's great statesmen, Wally Hickel, who was serving as Interior Secretary at the time."

Murkowski said both NOAA and Interior focus on the same types of work, such as offshore mapping and managing marine mammals, fish stocks and habitat.

Arctic exploration EIS cited

One unified agency would be better than "two in conflict," Murkowski said.

"For example, NOAA and Interior regularly conduct separate environmental reviews of the same projects, adding time to the approval process and crossing purposes," Murkowski wrote. "Case in point is NOAA's Draft Environmental Impact Statement for Arctic oil and gas development, which contemplates a needlessly restrictive and unrealistic program and is at odds with Interior's own assessment. Instead of coordination, the current arrangement routinely leads to conflict and confusion — and an uncertain path forward for those who wish to invest in our state."

NOAA Fisheries Service is the lead federal agency preparing the EIS, which lays out policy alternatives for issuance of permits and authorizations for seismic surveys and exploratory drilling over a five-year period through 2017. Interior's Bureau of Ocean Energy Management, which handles offshore leasing, is helping write the EIS as a "cooperating agency."

The draft EIS considers how industrial noise, vessel traffic and pollution might affect whales and other marine mammals.

The alternatives concern industry, placing annual limits on the number of seismic surveys and allowing only one or two exploratory drilling programs per year in each of the Beaufort and Chukchi seas.

The bipartisan Alaska congressional delegation, in a joint press release, said it had met April 18 with NOAA Administrator Jane Lubchenco to raise concerns "that the final EIS could create a set of further timing and spatial restrictions beyond those already listed in the leases held by oil companies."

Sen. Rockefeller 'appalled'

Obama can't move NOAA by himself. He has asked Congress to "reinstate the authority that past presidents have had to streamline and reform the Executive Branch."

A May 2 press release from Murkowski's office cites a "growing movement" in Washington, D.C., regarding the NOAA proposal.

Murkowski noted that both Commerce Secretary John Bryson and Interior Secretary Ken Salazar have indicated support for the move.

But consolidating NOAA within Interior certainly has opposition.

"I'm appalled by that thought," Sen. Jay Rockefeller, a West Virginia Democrat and chairman of the Senate Commerce Committee, said in a March 7 hearing on NOAA's budget. "I'm appalled by it. And I want to serve notice that I will do everything I can to make sure that it does not happen. And that's not because of territorial concerns, jurisdictional concerns. It simply doesn't make any sense."

Rockefeller said NOAA is an excellent organization now, with an excellent leader, and "I just want to make sure that NOAA's day-to-day performance stays on track."

Frances Beinecke, president of the Natural Resources Defense Council, has said relocating NOAA within Interior "is not merely some technical, bureaucratic shift."

She wrote in a January blog post: "Housing NOAA within a department whose focus on the oceans is almost entirely extractive (permitting offshore oil drilling and exploration, for example) could erode the capability and mute the voices of the government's chief oceans experts." ●

Contact Wesley Loy at wloy@petroleumnews.com

● UTILITIES

HEA moving ahead with system upgrades

Kenai Peninsula utility in process of building new natural gas generation facilities as part of its independent light program

By ALAN BAILEY
Petroleum News

Connected to the rest of the Alaska Railbelt electrical grid by a single intertie and with its power supply contract with Chugach Electric Association due to terminate at the end of 2013, Homer Electric Association, or HEA, the main power utility on the Kenai Peninsula, has been moving ahead with its so-called "independent light" program for future power supplies.

New generation

The independent light program, decided on by the HEA board in 2008, consists essentially of building and obtaining new power generation capacity on the peninsula to enable the utility to meet its own power generation needs. However, HEA will also purchase power from other Railbelt utilities when that makes economic sense, Brad Janorschke, HEA general manager, told the Regulatory Commission of Alaska on April 11 during an update to the commission on the current status of the utility.

"It's certainly different than treating ourselves as an island like Kodiak," Janorschke said.

Currently the utility obtains most of its power from Chugach Electric, while also obtaining about 39 megawatts from its own gas-fired power station at Nikiski on the west coast of the peninsula. The Bradley Lake hydroelectric facility in the southern Kenai Peninsula also provides about 14 megawatts for the peninsula, according to the HEA website. HEA's total annual demand is 84 megawatts, with a total system generation requirement of about 110 megawatts, the website says.

Of three short-listed options for HEA power supplies after the termination of the utility's Chugach Electric contract, the independent light program offered the lowest cost to HEA's ratepayers, Janorschke told the commission. The other options on the shortlist consisted of HEA participating in the new gas-fired power station that Chugach Electric and Municipal Light & Power are building in South Anchorage; and the continuation of the power supply contract with Chugach Electric, he said.

Main components

The two main components of the independent light plan consist of a major upgrade to HEA's Nikiski plant and the installation of gas-fired power generation in Soldotna, to the east of the city of Kenai.

HEA has also purchased the 69.9-megawatt Bernice Lake gas-fired power station near Nikiski from Chugach Electric, with that deal completing in late 2011.

In April 2011 HEA broke ground for a new power house at its Nikiski power station, to add a new high-efficiency, combined cycle, gas-fired, steam turbine generator to that facility.

"It will go from a 40-megawatt facility to a 58-megawatt facility with no more additional fuel," Janorschke said. The use of additional fuel would enable the plant to produce about 78 megawatts of power, he said.

The new turbine at Soldotna will have a 49-megawatt capacity, according to the HEA website.

The upgraded Nikiski plant should go on line late this year or early in 2013, with the Soldotna unit going on line in the summer of 2013, Janorschke said.

And the utility has built a new dispatch center at Nikiski to manage its power generation systems.

"We've got a lot of new investment in generation and we want to make sure it gets operated and maintained properly," Janorschke said.

Nikiski plant

The high-efficiency power plant in Nikiski will meet HEA's base load needs, while the Soldotna plant, located at the hub of the Kenai Peninsula grid and at the connection point with the transmission intertie to Anchorage, will meet peak power needs and also provide what are referred to as "spinning reserves," the extra power capacity that utilities keep in their back pockets to cover any potential supply shortfalls.

However, since the upgraded Nikiski power station will operate at maximum efficiency at 58 megawatts, upping the power output there or starting up relatively inefficient plants at Soldotna or Bernice Lake would increase the cost of the power. So if, say, HEA needed an extra two or three megawatts to cover a small spike in demand, the utility would first try to obtain cheaper power from active power units operated by other Railbelt utilities rather than starting up some of HEA's own systems to cover the load, Janorschke explained.

Contracted gas

Janorschke said that HEA has contracted with Hilcorp Alaska to meet all of the utility's natural gas needs from Jan. 1, 2014, to March 31, 2016, after the termination of the Chugach Electric power supply contract, with an option to extend the Hilcorp contract up to a further two years. Beyond that HEA faces the same gas supply uncertainties as other Southcentral utilities.

"In the long term we are going to be continuing to work with the other utilities and other entities to try to find out where we are going to get long-term gas for Alaska," Janorschke said.

Small gas producers in the Cook Inlet basin have been unwilling to commit to providing the bulk of HEA's gas supplies because, having very few wells, these producers do not wish to risk becoming a utility's sole-source provider, Janorschke said.

"They said go find a base load supply of gas from a large producer and then come back and talk to us about smaller increments. So that's what we've done," he said.

Hydropower

Looking out into the future, HEA has been working with other Railbelt utilities and with the Alaska Energy Authority on proposed new hydropower systems at Watana on the Susitna River and at Battle Creek. HEA has also proposed building its own small five-megawatt hydroelectric facility at Grant Lake, near Moose Pass on the Kenai Peninsula. The Grant Lake proposal has met with opposition from people concerned about potential environmental impacts — HEA has been addressing the concerns and is continuing with a study for the project, Janorschke said.

HEA has also signed an agreement with Ocean Renewable Power Co. for the development of a pilot tidal current generation system in Cook Inlet at East Foreland near Nikiski. And HEA's net metering system — the arrangement whereby the utility's members can connect their own small-scale renewable energy generators to the grid — has taken off, with 52 members now interconnected with HEA's system, Janorschke said.

Transmission upgrades

In parallel with its independent light power generation program HEA is upgrading the sparse and aging power transmission infrastructure on the Kenai Peninsula. The transmission line upgrades are being funded through a state grant.

Particularly critical are the transmission circuits between Soldotna, Nikiski and Kenai where, because of capacity constraints, there is in effect a single transmission line connecting the critical

see **HEA UPGRADES** *page 9*

● LAND & LEASING

DNR upholds rejection of Cohoe unit

Says Aurora Gas has not shown proposed Kenai Peninsula unit overlies oil or gas pool; lease expiry not a reason for unitization

By ALAN BAILEY
Petroleum News

Since July 2010 Cook Inlet independent Aurora Gas has been trying to persuade the State of Alaska to combine a couple of state leases near the community of Kasilof on the Kenai Peninsula with an adjoining Cook Inlet Region Inc. lease to form the Cohoe unit. The state leases had been due to expire in September 2010, but Aurora said that it wanted to conduct a seismic survey and do exploratory drilling in the proposed unit — unitization of the leases would head off the lease termination.

But all came to naught on May 3 when Dan Sullivan, commissioner of the Alaska Department of Natural Resources, issued a decision upholding an earlier Division of Oil and Gas rejection of the unitization request.

Sullivan said that he affirmed the finding of the division's director, William Barron, that it is "not in the state's interest to allow Aurora to retain the leases and benefit from the lease term extensions provided by unitization without having demonstrated the need for unitization."

"Aurora is obviously disappointed by the commissioner's decision to affirm the director's denial of the Cohoe unitization," Ed Jones, president of Aurora Gas, told Petroleum News in a May 8 email. Aurora does not plan a further appeal of the decision, he said.

Cohoe well

The leases in question include the Cohoe Unit No. 1 well, drilled by Unocal in 1973 to a depth of 15,683 feet, presumably in search of oil. The well bottomed out in the West Foreland formation. Drill stem tests conducted in nine zones at various levels in the well detected small amounts of natural gas in three of the zones, two in the Sterling formation and one in the Beluga formation.

Two consortia acquired the state leases in the 2003 Cook Inlet areawide lease sale, with Aurora subsequently acquiring the leases in March 2004. And in August 2006 Aurora leased the Cook Inlet Region Inc. acreage that forms part of the package that Aurora has subsequently wished to unitize.

According to Sullivan's May 3 decision document, no one has conducted any exploration work on the three leases in question over the past seven years, although Aurora has conducted a re-assessment of seismic and well data relating to the leases — in addition to the drilling of the 1973 Cohoe well, a seismic survey was conducted on the acreage in 1972.

After Aurora submitted its unitization request in 2010 there was a delay of a year or so in dealing with the request, while state officials waited for Aurora to submit a unit agreement that included both the state and Cook Inlet Region Inc.

And under that unit agreement Aurora proposed a two-year plan of exploration involving the re-entry of the old Cohoe well and the gathering of some new 3-D seismic data. Aurora told Petroleum News in 2010 that its preference would be to first conduct the seismic survey, to determine whether the Cohoe well had penetrated the crest of the geologic structure at Cohoe — depending on the seismic results the company might drill a new well in a different location, the company said.

The company also said that it hoped to head off lease termination, if necessary, by re-entering the Cohoe well before the lease expiry date. The company subsequently said that, because of drilling commitments on the west side of the Cook Inlet, it had not proved possible to move the Aurora Well Services No. 1 drilling rig to the Cohoe location prior to that lease expiry date.

Timely development

In his decision document Sullivan said that the primary purpose of state oil and gas leasing is to secure the timely development of state resources and that, under state statutes, the unitization of leases is intended for conserving an oil or gas pool to prevent waste; to ensure the maximum recovery of oil and gas; and to protect the correlative tights of people owning interests in the affected land.

"Thus, to justify a unit, the lessee should demonstrate that the leases contain a pool or field, that unitization will promote the efficient recovery of oil or gas, and that the lessee's plan to move the unitized leases into production requires unitization to conserve the resource and prevent waste," Sullivan wrote.

In the case of the Cohoe leases, Aurora Gas has not demonstrated that the proposed unit area lies over a hydrocarbon reservoir or pool, Sullivan wrote. No well has been drilled and tested that demonstrates the existence of hydrocarbons in paying quantities in any of the leases proposed for unitization, he wrote. And data presented by Aurora do not define and delineate a geologic structure that would be capable of trapping an oil or gas pool, he wrote.

Aurora had argued that the proximity of the Cohoe well to the border of the Cook Inlet Region Inc. land led to a need for unitization of the state and private leases, to enable development of the land to proceed — the Cohoe well is in state land but is located within 20 feet of the boundary with the Cook Inlet Region Inc. land, Aurora said.

However, Sullivan said that the lack of evidence for a hydrocarbon pool in the leases rendered moot any other arguments for unitization.

Lease expiry irrelevant

Moreover, no statute or regulation gives lease expiry as a basis for unitizing leases, and the expiration of the leases does not in itself justify the formation of a unit, Sullivan wrote. And a review of past state unitization decisions does not support a contention by Aurora that the state has pre-

see COHOE UNIT page 9

NATURAL GAS

Nikolaevsk next up for natural gas

The tiny village of Nikolaevsk could soon become the second community in the southern Kenai Peninsula to be added to the Southcentral natural gas distribution grid.

The Armstrong Oil & Gas Inc. subsidiary Anchor Point Energy LLC recently asked state regulators to approve an agreement with Enstar Natural Gas Co. that would deliver supplies from the North Fork unit to the small community just north of the city of Homer.

Approval from the Regulatory Commission of Alaska would allow Enstar to use a $447,000 grant from the state to add an interconnection to the North Fork Pipeline.

With "prompt approval" by the RCA, the Nikolaevsk Community School and the local fire station could convert their heating systems this summer in advance of next winter.

8,930-foot 2-inch line

If given the go ahead, Enstar would build a regulator station at the North Fork Pipeline and a two-inch pipeline running 8,930 feet to a recently built regulator station at the school. While the school will likely be the largest customer, Enstar expects to eventually add the fire station and 12 homes during the initial build out. As of October 2011, Enstar had installed nearly two miles of distribution main pipelines throughout Nikolaevsk.

The RCA added Nikolaevsk to the Enstar service area in 1997.

The community is home to some 308 people, according to the state.

While the North Fork Pipeline is currently feeding into the regional distribution grid, communities in the southern Kenai Peninsula see it as a chance to get off heating oil.

The pipeline is currently delivering supplies to the coastal community of Anchor Point, but is not yet connected down to Homer and Kachemak, home to nearly 6,000 people.

The Alaska Legislature approved an $8.15 million line item for that project, but Gov. Sean Parnell has yet to release his final vetoes for the fiscal year 2013 capital budget.

—ERIC LIDJI

● GOVERNMENT

Interior requires chemicals disclosure

New drilling rules on public land set standards for well construction, wastewater disposal; chemical disclosure after drilling

By MATTHEW DALY
Associated Press

The Obama administration said May 4 it will for the first time require companies drilling for oil and natural gas on public and Indian lands to publicly disclose chemicals used in hydraulic fracturing operations.

The proposed "fracking" rules also set standards for proper construction of wells and wastewater disposal.

Interior Secretary Ken Salazar said the long-awaited rules will allow continued expansion of drilling while protecting public health and safety.

"As we continue to offer millions of acres of America's public lands for oil and gas development, it is critical that the public have full confidence that the right safety and environmental protections are in place," Salazar said.

The proposed rules will "modernize our management of well-stimulation activities, including hydraulic fracturing, to make sure that fracturing operations conducted on public and Indian lands follow common-sense industry best practices," he said.

The new rules, which have been under consideration for a year and a half, were softened after industry groups expressed strong concerns about an initial proposal leaked earlier this year. The proposal would allow companies to file disclosure reports after drilling operations are completed, rather than before they begin, as initially proposed. Industry groups said the earlier proposal could have caused lengthy delays.

Some environmental groups criticized the change as a cave-in to industry, but Salazar said the rules were never intended to cause delays, but to ensure that the public is "fully aware of the chemicals that are being injected into the underground" by companies seeking to produce oil and natural gas.

Some 90% use fracturing

The Bureau of Land Management, which oversees drilling on public lands, estimates that 90 percent of the approximately 3,400 wells currently drilled on federal and Indian lands using hydraulic fracturing techniques.

The rules would not affect drilling on private land, where the bulk of shale exploration is taking place. A nationwide drilling boom in formations such as the Marcellus Shale in the Appalachian region and the Bakken in North Dakota and Montana, as well as in traditional production states such as Texas, Oklahoma and Louisiana, has led to 10-year lows in natural gas prices.

Still, Salazar said he hopes the new rules could be used as a model for state regulators.

"We hope our leadership is followed," he said at a news conference.

Industry groups and Republican lawmakers say federal rules are unnecessary, arguing that states already regulate hydraulic fracturing, in which water, sand and chemicals are in injected underground to break up dense rock that holds oil and gas.

Trade secrets an issue

The industry also has complained that disclosure of chemicals used in fracking could violate trade secrets, although Salazar said the rule would include exemptions for specific formulas. Some of the chemicals used in fracking include benzene, toluene, ethylbenzene and xylene, all of which can cause health problems in significant doses.

Critics say fracking chemicals have polluted water supplies, but supporters say there is no proof.

Tom Amontree, executive vice president for America's Natural Gas Alliance, an industry group, said the Obama administration "may not fully appreciate" significant regulatory steps taken by states such as Colorado, Texas and Wyoming to oversee hydraulic fracturing.

"State regulatory bodies have repeatedly proven that they have the understanding of their state's own unique geologic conditions, the on-the-ground expertise needed to oversee this important work, and most importantly, the ability to respond to rapid change," Amontree said. As drafted, the federal proposal would create reporting requirements and "regulatory impediments" that could substantially affect the ability of companies to drill on public lands, he said.

The proposed rules will be subject to public comment for 60 days, with a final order expected by the end of the year, said BLM Director Bob Abbey. ●

● FINANCE & ECONOMY

EIA forecasts lower WTI crude oil prices

US total crude oil production expected to average 6.2 million bpd this year, up 500,000 bpd from 2011 and highest level since 1998

By KRISTEN NELSON
Petroleum News

Crude oil prices are dropping and U.S. crude oil production is rising, the U.S. Energy Information Administration said in its May short-term energy forecast, released May 8.

EIA is now forecasting a $110 per barrel U.S. refiner acquisition cost this year, down $2.50 per barrel from the April outlook, and a West Texas Intermediate crude oil price of $104 per barrel this year, down about $2 per barrel from the April outlook.

The WTI price is $9 a barrel higher than the average price last year and the U.S. refiner acquisition cost is about $8 per barrel higher than in 2011. EIA said it expects crude oil prices to remain relatively flat in 2013.

US production highest since 1998

U.S. crude oil production is expected to average 6.2 million barrels per day this year, up 500,000 bpd from 2011 — the highest level of production since 1998, EIA said.

In 2011, U.S. crude oil production increased an estimated 190,000 bpd, 3.4 percent, to 5.66 million bpd, with an increase of 450,000 bpd in Lower 48 onshore production partly offset by a 30,000 bpd decline in Alaska and a 230,000 bpd decline in the federal Gulf of Mexico.

The EIA's forecast of 6.17 million bpd for this year is up 150,000 bpd from the agency's April forecast, "and the highest level of production since 1998."

The agency said the rise in production is driven "by increased oil-directed drilling activity, particularly in onshore tight oil formations," with the number of oil-directed rigs reported by Baker Hughes up from 777 at the beginning of 2011 to 1,355 on May 4.

The share of U.S. consumption met by liquid imports (including crude oil and products) has been falling since 2005, EIA said, averaging 45 percent in 2011, down from 49 percent in 2010.

The total net import share of U.S. consumption is expected to "continue to decline to 43 percent in 2012 and 42 percent in 2013," the agency said.

US natural gas increases

EIA said total marketed production of natural gas in the U.S. grew by an estimated 4.8 billion cubic feet per day (7.9 percent) in 2011, "driven in large part by increases in shale gas production."

The agency said it expects year-over-year production to continue to grow this year, but "at a slower rate than in 2011 as low prices reduce new drilling plans." EIA said Baker Hughes reported a natural gas rig count of 613 at the end of April, the lowest gas-related rig count since 2002, and down from a 2011 high of 936 in mid-October.

EIA attributes a drop in natural gas marketed production from January to February to declining production from less-profitable dry natural gas plays such as the Haynesville Shale being offset by more production from liquids-rich areas such as the Eagle Ford and wet areas of the Marcellus Shale.

Gross pipeline imports are expected to fall by 0.3 bcf per day (3.3 percent) this year as domestic supply displaces Canadian sources, with warm weather in the U.S. adding to the year-over-year decline in imports, particularly in the Northeast.

Gross pipeline exports grew by 1 bcf per day last year, driven by increased exports to Mexico the EIA said, and are expected to continue to grow at a slower rate in 2012 and 2013.

Henry Hub natural gas spot prices averaged $1.95 per million British thermal units in April, down 23 cents per million Btu from March "and the lowest average monthly price since March 1999, which also was the last time the Henry Hub price averaged less than $2 per MMBtu," EIA said.

The agency said abundant supplies and lower winter heating demand contributed to recent low prices.

EIA said it expects the Henry Hub natural gas price to average $2.45 per million Btu this year and $3.17 in 2013, down from April forecasts of $2.51 and $3.40 per million Btu, respectively. ●

Contact Kristen Nelson at knelson@petroleumnews.com

EXPLORATION & PRODUCTION

US oil, gas rig count up by 20 to 1,965

The number of rigs actively exploring for oil and natural gas in the U.S. was up 20 the week ending May 4 to 1,965.

Houston-based oilfield services company Baker Hughes Inc. reported that 1,355 rigs were exploring for oil and 606 were looking for gas. Four were listed as miscellaneous. A year ago this week, Baker Hughes reported 1,836 rigs.

Of the major oil- and gas-producing states, Texas gained eight rigs, Louisiana and New Mexico each gained four, California gained two and North Dakota gained one.

Alaska and Colorado each lost two rigs while Pennsylvania and West Virginia each lost one. Arkansas, Oklahoma and Wyoming were unchanged.

The rig count peaked at 4,530 in 1981 and bottomed at 488 in 1999.

—ASSOCIATED PRESS

continued from page 7

COHOE UNIT

viously granted the unitization of leases when needed for exploration, he wrote.

"Unitizing state leases in this situation would make the primary term of the lease meaningless," Sullivan wrote. "If these non-producing leases that have not been adequately explored during the primary term can be unitized on eve of their expiration date, and then remain in force through unitization, this essentially circumvents the lessee's statutory and contractual obligation to explore and develop during the primary term of the lease." ●

Contact Alan Bailey at abailey@petroleumnews.com

continued from page 6

HEA UPGRADES

power generation system at Nikiski to the rest of the power grid. An upgrade of the line that carries power between Nikiski and Soldotna from 69 kilovolts to 115 kilovolts will rectify that particular problem — work on that upgrade will probably start next winter, Janorschke said.

HEA is also upgrading some electricity substations on the peninsula.

The best option for further improvements to the stability of the power supplies on the Kenai Peninsula would be the installation of a second transmission intertie between Anchorage and the peninsula, Janorschke said. That "would do wonders for everybody and I think is where we have to go eventually," he said. ●

Contact Alan Bailey at abailey@petroleumnews.com

LAND & LEASING

Potential Alaska state and federal oil and gas lease sales

Agency	Sale and Area	Proposed Date
DNR	Cook Inlet 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:

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● NATURAL GAS

Touting Alaska gas in nation's capital

DNR commissioner goes to Washington, DC, to talk up state's energy agenda, and to urge prompt Point Thomson permitting

By WESLEY LOY
For Petroleum News

Dan Sullivan, Alaska's natural resources commissioner, recently lit out for Washington, D.C., with a 22-page presentation under his arm titled, "Alaska Gas Opportunities."

By the time his weeklong visit was over, the report was marked up and dog-eared from showing it over and over to senior Obama administration officials, business people, diplomats and one notably contrarian congressman.

SHANE LASLEY

DAN SULLIVAN

Sullivan's inspiration for the April 23-27 trip was the recent evolution of Alaska's energy development strategy.

On March 30, the three major oil companies operating in Alaska — BP, ConocoPhillips and ExxonMobil — said they would work together to assess a possible liquefied natural gas export project. Sullivan's boss, Gov. Sean Parnell, had encouraged the companies to align on the LNG idea, a departure from their previous focus on constructing a gas pipeline into Canada.

On the same day, the state announced it had finalized a settlement with ExxonMobil over the disputed Point Thomson field. The field is considered important for any gas development, holding perhaps a quarter of the North Slope's gas reserves.

'Not just waiting'

Sullivan, in a May 7 interview with Petroleum News, said he took the Washington trip to tout Alaska's "comparative advantages," and to urge federal officials not to allow further permitting delays for the inaugural Point Thomson development.

ExxonMobil is waiting for a wetlands permit from the U.S. Army Corps of Engineers for its planned gas condensate project at Point Thomson, located on the Beaufort Sea coast next to the Arctic National Wildlife Refuge. The company's original target date for first production has slipped by more than a year due to repeated delays in finishing an environmental impact statement. The Corps now expects to issue the final EIS in June.

With the alignment of the major oil companies, and the strong market for gas in Asia, the time to promote Alaska is now, he said.

"We're not just waiting," Sullivan said.

That presentation he took on his trip was designed to explain, starting with the basics, what Alaska has to offer in terms of billions of barrels of oil and many trillions of cubic feet of gas.

Sullivan pointed out that Alaska already has a long and unique record of Asian exports via the ConocoPhillips LNG facility on Cook Inlet.

Further, Sullivan made sure to point out that Alaska gas is "not part of the shale LNG export debate in the Lower 48," as Alaska exports wouldn't affect Lower 48 gas supply and prices.

And he explained that exporting North Slope gas would "help Americans — they're called Alaskans."

Long visitation list

Certainly, Sullivan knows his way around Washington. Under President George W. Bush, Sullivan served as the assistant secretary of state for economic, energy and business affairs.

After that, he served as Alaska's attorney general from June 2009 until December 2010, when Parnell appointed him natural resources commissioner.

Sullivan's Washington visitation list was lengthy. He said he had meetings with:

• Deputy Secretary of Energy Daniel Poneman, the department's second highest ranking official.

• Deputy Interior Secretary David Hayes, the department's second highest ranking official.

• Bob Cekuta, principal deputy assistant secretary in the State Department's new Bureau of Energy Resources, assigned to Tokyo from 2007-09.

• White House official Heather Zichal, the deputy assistant to the president for energy and climate change.

• Daniel Yergin, prize-winning author, CNBC energy analyst and chairman and founder of IHS Cambridge Energy Research Associates.

• Ichiro Fujisaki, Japan ambassador to the United States.

Sullivan said he also made a presentation at the Center for Strategic and International Studies, heard from Goldman Sachs investment bankers on global LNG trends, and met with potential LNG customers.

Export resistance

Sullivan isn't the first Alaska official to come calling in the nation's capital, and he

see SULLIVAN IN DC page 14

● FINANCE & ECONOMY

State, BP heading into arbitration

At issue is potentially hundreds of millions of dollars in compensation for production shortfalls after 2006 spills at Prudhoe Bay

By WESLEY LOY
For Petroleum News

The state and BP are about to begin arbitration proceedings over the 2006 pipeline leaks in the Prudhoe Bay oil field.

The stakes are high, with potentially hundreds of millions of dollars on the line.

The arbitration stems from a civil suit the state filed against BP Exploration (Alaska) Inc. in March 2009 in state Superior Court in Anchorage.

The suit came after a pair of oil spills at Prudhoe, which BP operates for an ownership group that also includes ConocoPhillips, ExxonMobil and Chevron.

One spill, at 212,252 gallons, was the largest oil spill ever on Alaska's North Slope.

The spills were from corroded oil transit lines that feed sales-grade crude into the trans-Alaska pipeline.

BP Alaska was convicted of a federal environmental misdemeanor, which resolved the criminal aspect of the matter.

Back taxes, royalties sought

The state's subsequent civil suit alleged negligence and sought a range of damages from BP.

Most significantly, the suit sought back taxes and royalties to compensate the state for what it contended were production shortfalls of at least 35 million barrels of oil and natural gas liquids from Prudhoe and the neighboring Milne Point field.

These shortfalls, from 2006 through 2008, resulted from "massive production shut-ins" due to the spills and subsequent replacement of corroded pipelines, the suit said.

A judge in December 2010 threw out the state's tax claim, hugely reducing BP's potential liability in the lawsuit.

The case is now on hold while the state and BP take the remaining royalty claim to binding arbitration.

Private proceedings

On May 3, lawyers for the state filed a brief status report saying: "An arbitration panel has been selected, and the arbitration in this matter is scheduled to begin on May 22."

Steve Mulder, the state's lead attorney on the case, did not respond by press time to a Petroleum News request for more information. However, he previously has provided details about the arbitration.

The panel of three arbitrators was agreed to by each side. The arbitration will be conducted privately, but the result will be made public.

"Much of the information likely to be presented at the arbitration is subject to protective orders entered by the Superior Court because it is considered confidential business information," Mulder said in a March 1 email. "For this reason, the arbitration proceeding itself will not be open to the public."

How much money?

The state will ask the arbitration panel to award an amount to compensate the state for the royalties it did not receive due to production shut-ins stemming from the pipeline leaks.

"The arbitration will focus on whether BP 'made-up' the lost production shortly after putting into service replacement pipelines or whether the production opportunity lost in 2006-08 will not be realized until the end of field life, if ever, due to known gas and water handling constraints," Mulder said in a Jan. 10 email.

It's not known exactly how much money the state is seeking.

But conceivably, if at arbitration the state is able to show that it is due a 12.5 percent royalty on the full 35-million-barrel production shortfall alleged in the suit, that would be about $328 million at $75 per barrel. ●

Contact Wesley Loy at wloy@petroleumnews.com

NATURAL GAS

FNG gets Cook Inlet supply extension

Fairbanks Natural Gas LLC recently extended its Cook Inlet supply contract by one year.

The extension now gives the Fairbanks gas distribution utility until May 31, 2014, to switch its supply source to the North Slope, the company recently told regulators.

In March, the Regulatory Commission of Alaska granted Fairbanks Natural Gas-affiliate Polar LNG LLC a certificate to build and operate a common carrier pipeline at Prudhoe Bay that would eventually feed a liquefied natural gas plant to be built at Deadhorse.

Polar LNG recently applied for a pipeline right-of-way lease from the State Pipeline Coordinator's Office. The pipeline would run some 3.5 miles from Flow Station 1 at the Prudhoe Bay unit to the Polar LNG Pas, formerly known as Child's Pad) in Deadhorse.

Fairbanks Natural Gas currently trucks LNG north from Cook Inlet, but in early 2008 secured a 10-year contract to buy North Slope gas from an ExxonMobil subsidiary.

The Cook Inlet supply currently serves as a feedstock for an LNG facility at Point MacKenzie. Fairbanks Natural Gas currently trucks LNG north along the Parks Highway.

While Fairbanks Natural Gas and Polar LNG work to bring the project online, Golden Valley Electric Association and Flint Hill Resources Alaska are also considering a plan to truck LNG from the North Slope to the Interior starting in early 2014. The Polar LNG project would likely require big anchor customers like the power utility and the refinery.

—ERIC LIDJI

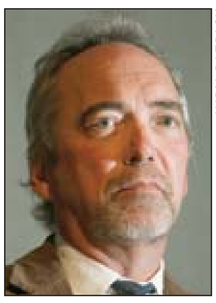
● EXPLORATION & PRODUCTION

Great Bear's Duncan: 'In it together'

A more conservative, but not subdued, Duncan declines to testify to Senate Resources Committee on tax breaks needed for project

By KAY CASHMAN
Petroleum News

Hours before Gov. Sean Parnell abruptly withdrew his revised production tax bill from consideration by a special session of the Alaska Legislature because of lack of support in the Senate, Great Bear Petroleum's top executive, Ed Duncan, addressed the Senate Resources committee, in testimony that was supposed to address the governor's compromise tax bill, Senate and House bills 3001.


JUDY PATRICK
ED DUNCAN

Although more conservative in terms of what his company's pioneering efforts in oil extraction from Northern Alaska's three great source rocks might contribute to the state's declining oil production, Duncan did not offer a positive or negative comment on SB 3001, although he did say that Great Bear officials "are amazed at the cost differential between North Alaska" and the much lower-cost South Texas, "whether it's rig rates, whether it's labor costs, whether it's the cost of pipe, wellheads, you name it, it's there."

But with Great Bear just starting its multi-well, proof of concept drilling and testing phase, expected to last until the end of December, followed by a one-year pilot production test, Duncan made it clear that he still does not know whether Alaska's source rocks can be enticed to produce commercial qualities of oil and natural gas liquids, and thus what the state of Alaska can do to help his company and others.


Great Bear Petroleum Operating LLC

North Alaska Shale Resource Play Realization: Challenges and Business Development Opportunities

- •Gravel Supply: *Regionally available*
- •Water Supply: *Extensive subsurface brackish aquifer sources*
- •Sand (Proppant) Supply: *Intra-State opportunity and global suppliers*
- •Gathering Systems (Tanks/Trucks or Pipelines or Both): *Long term, skilled employment*
- •Fluid Disposal/Recycling: *Existing and new facilities*
- •Gas use/disposal in area: *Power generation, liquids and longer term gas line export*
- •Surface Impacts/Dust and Emissions: *AC Rigs and multi-well development pads*
- •Centralized Service Area with power source: *Modular startup transitioning to centralized*
- •Power distribution – Stand alone per pad; through power lines: *"Utility" grid corridors*
- •Use of Insulation and composite pads to extend ice pads and roads: *Not fit for development*
- •Staging area for pipe, equipment, housing, warehousing: *Existing facilities and purpose built*
- •Road and bridge requirements: *Design to minimize surface impact*
- •Fuel Refining, Storage and Distribution: *Existing facilities and custom*
- •Drinking Water Supply: *Multiple options identified included desalination of subsurface water*
- •Sewage Treatment/Disposal: *Existing and custom in-field facilities planned*
- •Trucking Impacts: *Maximize development design efficiencies*

COURTESY GREAT BEAR PETROLEUM

1 2 SERIES

So when asked by Sen. Lesil McGuire to contribute to the tax dialogue about "any potential (production tax) bill that could come out of this session" and whether he had "a preference in what type of incentive the state would offer," Duncan responded with a question that defined his goal for state participation in what he referred to numerous times in his testimony as shared state/industry/societal concerns and challenges.

Make Alaska competitive with lower 48 states

"What are the things that the state can do, realistically do, to help us push the finding and development costs in North Alaska down to something that competes (with), or is better than — let's make it better than — the Lower 48. Let's turn this thing around," he said.

But Duncan said he "preferred" that the answer(s) "be the product of a different type of discussion than the answer to a simple question because we can lay out to you where our big cost points are, things that keep me awake at night, and let's engage the bigger brain of the state and the industry to solve that problem because it doesn't just solve it for us — it solves it for everybody on the map."

> *"So for our operations in North Alaska we don't see shallow aquifers as being a significant challenge."* **—Ed Duncan, Great Bear Petroleum**

"We're all in this together — that's the other thing that is critical here. The challenge isn't just Great Bear's, or the challenge isn't just the state of Alaska's … the challenge effects everyone from the super majors on the Slope to the smallest company," he said many times, in different ways, in his testimony.

Duncan was "happy" to answer McGuire's question, but not then and there.

Rather, he wanted to begin the discussion after May 8, explaining that "the week after next our all-internal task force on cost-reduction meets. I guess it's the eighth of May. And I would propose … we join with the state following those meetings — and we'll have those regularly — and work through where we see major cost drivers and places where the state maybe could facilitate significant cost reductions. … I consider those things good and proper incentives for us without me trying to prescribe what those would

see **GREAT BEAR** *page 19*

EXPLORATION & PRODUCTION

ConocoPhillips still planning for CD-5

It has been four or five months since the Corps of Engineers approved the Colville River crossing that ConocoPhillips needs for its CD-5 oil field development in the northeastern corner of the National Petroleum Reserve-Alaska, and the company is progressing its planning for the project, with the objective of obtaining board approval for the field development.

"We are evaluating and incorporating the terms of the Corps of Engineers permit into our project plan, and working out engineering and design details in order to take the project to the COP board for sanctioning later this year," ConocoPhillips spokeswoman Natalie Lowman told Petroleum News in a May 4 email. Lowman told Petroleum News in December, after the Corps decision, that ConocoPhillips anticipates starting construction at CD-5 in the winter of 2014, with construction continuing during the following winter and first oil coming on line in 2015.

—ALAN BAILEY

Shell asks court to declare IHAs valid

In the latest of a series of court actions designed to pre-empt last minute litigation against its planned Arctic outer continental shelf drilling this year, Shell has filed a petition with the federal District Court in Alaska, asking the court to rule that the National Marine Fisheries Service properly issued incidental harassment authorizations, or IHAs, for Shell's drilling operations.

The IHAs mandate measures that Shell must take to avoid disturbing marine mammals or subsistence hunting when drilling in the Beaufort and Chukchi Seas, while also allowing the accidental disturbance of small numbers of marine mammals without the company running afoul of the Marine Mammals Protection Act.

The court petition targets 14 environmental groups which Shell says oppose the company's Arctic drilling plans and which the company says have a track record of appealing permit decisions.

"Their prior statements and past practice make it a virtual certainty that they will litigate the approval of the IHAs," wrote attorney Kyle Parker in Shell's petition, filed May 3. Shell's pre-emptive court action will provide the court with sufficient time to make a reasoned evaluation of the Fisheries Service decision, Parker wrote. Shell plans to start its initial drilling operations in July in the Chukchi Sea. The company has already filed a similar petition with the District Court, asking the court to affirm approval of the company's oil spill response plans by the Bureau of Safety and Environmental Enforcement.

The U.S. Court of Appeals for the 9th Circuit is already considering appeals by environmental groups and some Native organizations against the approval of Shell's Chukchi Sea and Beaufort Sea exploration plans, against the air permit for the Noble Discoverer drillship that Shell plans to use, and against the lease sale in which Shell obtained its Chukchi Sea leases.

—ALAN BAILEY

ASSOCIATIONS

COURTESY AEDC

Alaska Sen. Mark Begich addresses attendees at the 2012 Anchorage Economic Development Corp. Resource Extraction 10-Year Project Projection event.

AEDC releases annual resource forecast

On May 2, the Anchorage Economic Development Corp. held its annual event celebrating the release of its latest resource extraction projection report at the Downtown Marriott Hotel.

Sponsored by Northrim Bank, the 2012 AEDC Resource Extraction 10-Year Project Projection focused on the oil, gas and mining projects in the state over the next 10 years and the economic impacts of those developments.

The event, which included hors d'oeuvres and a no host bar, featured a live speech by U.S. Senator Mark Begich, D-Alaska, and a DVD presentation by U.S. Senator Lisa Murkowski, R-Alaska, who shared their thoughts on the oil and gas and mining opportunities in Alaska over the next decade from a federal perspective.

AEDC's President and CEO Bill Popp said the 2012 job estimate for the projects increased this year to 19,341 and also noted that the total dollars proposed for investment decreased slightly from \$33.7 billion in 2011 to \$30.4 billion in 2012.

Most projects moved back another year in the timeline for varying reasons including permit challenges, litigation, project plan changes, etc.

Popp said AEDC has seen modest progress in moving projects forward but challenges still remain for many of the developments.

The research for the report was provided by North of 60 Mining News editor Shane Lasley and by Dan Dickinson and Mary Ann Pease under contract to

see **AEDC FORECAST** page 19

continued from page 10

SULLIVAN IN DC

surely won't be the last.

The fact is, gas development has defied one Alaska governor after another. Any project to develop the state's gas involves long lead times, enormous cost and huge risk. And so the gas has stayed stuck in the ground decades after its discovery.

An explosion of shale gas in the Lower 48 has stoked interest in possible U.S. gas exports, and this in turn has provoked a backlash from people such as Rep. Ed Markey, D-Mass. He has introduced bills to discourage exports, saying the gas is needed at home.

After the announcement about BP, ConocoPhillips and ExxonMobil aligning on a possible Alaska LNG project, Markey put out a March 21 press release saying in part: "When we bought Alaska from the Russians for only \$7 million, we got a great deal. If America now turns around and allows the big oil companies to sell off America's natural gas resources in Alaska and elsewhere to the Chinese, Uncle Sam really would deserve to be called Uncle Sucker."

Markey asserted that exporting Alaska gas could increase domestic prices, hurting American manufacturing.

Naturally, Sullivan made a point of meeting with Markey, too, during his Washington week. ●

Contact Wesley Loy at wloy@petroleumnews.com

● NATURAL GAS

Study says US LNG exports feasible

Brookings Institution study finds that there should be enough L48 natural gas to export some as LNG to the benefit of the US

By ALAN BAILEY
Petroleum News

A year-long study by the Brookings Institution, a non-partisan public policy organization, has found that the export of at least some LNG from the United States is likely to be both feasible and in the country's best interests. The study, which focused on the export of LNG from the Lower 48 states rather than from Alaska, found that although the export of LNG would likely somewhat increase natural gas prices in the United States, the economic benefits derived from the exports would more than offset any negative impacts from the higher cost of gas for U.S. consumers.

And the study authors cautioned against government interference in the LNG market, saying that this type of interference would likely cause undesirable, unintended consequences as a result of, in effect, subsidizing U.S. gas consumers at the expense of gas producers.

To inform its research the institution assembled a task force of 17 experts from consulting firms and academia.

Shale gas

The starting point for the study report is the rapid growth in shale gas production in the United States. This production growth is creating a situation where the country has an excess of gas supply over internal gas demand, thus potentially creating a source of gas to export into international LNG markets.

Experts in the gas industry say that evolving shale gas technologies are overcoming problems with the sustainability of production from shale gas plays, although questions over the environmental impacts of shale gas development are still causing concern and some uncertainty. And there are some significant issues associated with the shortage of sufficient pipeline and storage capacity to handle elevated levels of gas production, and hence to ship gas to future LNG facilities, the study says. The availability of people and equipment for shale gas drilling is also tight.

On the gas demand side of the situation, the study authors say that most internal U.S. gas demand will come from power generation and industrial gas usage, with the U.S. demand for gas in transportation and in the commercial and residential sectors likely to be quite modest.

Taking into account the various U.S. supply and demand factors, together with the associated uncertainties, the increased export of gas as LNG from the United States does appear technically feasible, the study has found.

Global market

But what about the global gas market into which the LNG would need to be sold?

In what the study refers to as the Pacific basin, the region including the countries of southeast and east Asia, growing gas demand, limited local supplies and high, rigid gas prices linked to oil prices provide the United States with a near-to-medium term gas export opportunity, the study says. There are, however, uncertainties relating to the possibility of indigenous shale gas development in, say, China or India. Expanded LNG exports from Alaska and new LNG supplies from Canada could also compete with LNG from the U.S. Gulf coast, the study says.

The study says that the transportation cost of LNG from Alaska to the Pacific Rim could be higher or lower than from the Gulf of Mexico, depending on the scale of Alaska LNG production.

In the Atlantic basin U.S. LNG would be competing with piped gas, especially from Russia, and with global LNG in a market where European countries have been pushing for gas prices lower than the traditional oil-indexed levels.

U.S. prices

Several studies, including a study by the Energy Information Agency, have investigated the potential impact of exporting LNG on domestic U.S. gas prices. All of these studies have concluded that the linkage of the U.S. gas market to the global LNG market would push up gas prices in the U.S., but there is a very wide range in the estimates of the scale of the price impact. A comparison of the assumptions behind these various studies suggests that, taking into account for example constraints on the realistic scale of LNG export facilities, the price impact would be fairly modest, the study concluded. And constraints on export volumes resulting from the relatively stable capacity of the export facilities would dampen any price volatility.

In addition to providing a valuable export, thus lowering the U.S. trade deficit, the overseas sale of LNG would provide a market for surplus "dry" natural gas, large volumes of which are currently being flared as companies push ahead with the production of valuable natural gas liquids from "wet" gas.

Dry gas consists of methane, while wet gas contains both methane and natural gas liquids such as ethane and propane.

In fact, the ability to readily sell dry gas might actually boost wet gas production, thus providing increased volumes of low-cost feedstock for an increasingly competitive U.S. petrochemical industry, the study report says.

Energy security

From the perspective of U.S. energy security, the volumes of LNG likely to be exported would not have any material effect on the availability of gas in the U.S. domestic market, while creating a market for gas produced along with oil could improve the economics of U.S. shale oil development, the study report says.

Internationally, the introduction of competitively priced U.S. LNG into the global gas market would likely put downwards pressure on global gas pricing. And the entry of the U.S. into the global market for gas supplies would strengthen U.S. foreign policy interests and enable the United States to assist its strategic allies in meeting their energy needs, the study concluded. ●

Contact Alan Bailey at abailey@petroleumnews.com

● NATURAL GAS

Distributing North Slope gas challenging

Enough gas exists to meet Alaska's needs for decades, but at a cost; and getting gas to rural areas more difficult and costly yet

By BILL WHITE

Researcher/writer for the Office of the Federal Coordinator

Fairbanks: the cost of getting warm

Fairbanks North Star Borough residents currently are out in the cold when it comes to low-cost energy to heat their homes, stores and office buildings.

Mostly they burn fuel oil to generate heat, with the price chained to today's high oil prices — the highest winter prices ever for Alaska North Slope oil.

1 2 3 SERIES

Fuel oil cost about $27.67 per million Btu of energy (or $3.84 a gallon) during the just-ended winter, according to a preliminary study for the borough released in February. (The price this spring was over $4 a gallon, but for this article we've stuck with the $3.84 used in the new study.)

Fairbanks lies far off the natural gas grid built for Anchorage and other communities near Alaska's Cook Inlet fields to the south. About 1,100 customers in Fairbanks — mostly commercial accounts — burn natural gas that a distributor purchases from Cook Inlet producers, superchills into liquefied natural gas for ease of transport, then trucks 300 miles to town. Of roughly 25,000 homes in the borough, fewer than 500 burn gas, the preliminary study by Northern Economics found.

All that handling and the small economies of scale make delivered natural gas pricey for Fairbanks consumers — $23.35 per million Btu, compared with about $8.60 in Anchorage and a similar price in the Lower 48. But $23.35 looks attractive compared with heating oil prices — Fairbanks households would save an average of $820 a year if they were burning gas at $23.35 rather than oil at $27.67, the study estimated.

BILL WHJITE

If the delivered cost could be slashed to $14 per million Btu through mass conversions to gas heating, economies of scale and other efficiencies, the average household savings would approach $2,600 a year, the study found.

Fairbanks-wide, the heating-cost savings for all users, not just households, would total $114 million a year at today's oil and gas prices, or $238 million if the delivered gas price were $14 and today's high oil prices lingered, the report said.

The North Pole Expansion Plant currently runs on naphtha, but could be converted to natural gas.

The report also noted additional savings in electricity bills if a Golden Valley Electric Association turbine in North Pole that now burns a costly oil-based fuel called naphtha switched to natural gas. But it did not quantify the potential savings to consumers.

A 2009 study for the Alaska Natural Gas Development Authority pegged the potential annual savings to Golden Valley in the low millions of dollars a year if it switched from naphtha to propane extracted from North Slope natural gas. Last year, Golden Valley began investigating how much it might save if it switched to LNG trucked from Prudhoe Bay; its rough estimate is that its fuel savings would reach as much as about $20 million a year at today's oil price of about $120 a barrel.

A billion-dollar build out?

Piping natural gas to Fairbanks homes and businesses would be an expensive undertaking, according to estimates collected from a variety of studies and reports.

Someone would need to snake a network of gas pipelines through town to individual furnaces.

In a sense, the network would resemble a road system. The big North Slope gas line through Alaska would be the freeway. Gas would exit that line into a multimillion-dollar lateral pipe that would channel gas to Fairbanks (think of this pipe as a four-lane highway, as opposed to an interstate freeway). Once in Fairbanks the gas would enter transmission lines that would route gas to different parts of town (like main streets routing traffic), then into feeder pipes (neighborhood feeder streets), then distribution lines (neighborhood streets) and finally service lines to houses and buildings (driveways).

No one has definitively nailed down the cost of such a system. But rough estimates put the total cost at possibly $580 million to $930 million for infrastructure to handle gas after it leaves an Alaska gas pipeline somewhere outside of Fairbanks. That price range is obtained by combining estimates from two studies released in the past 12 months. Consider the cost range to be soft.

Here's how that cost breaks down:

Delivering gas to Fairbanks

From a North Slope methane and gas-liquids pipeline
$210 million • Straddle plant
$60 million • Spur pipeline
$309-$662M • Gas pipelines within town
$25-$200 million? • Conversion of homes to use natural gas

Sources: Northern Economics; Alaska Gasline Development Corp.

$210 million

This is an estimated cost of a straddle plant alongside a big gas trunkline.

The plant would solve two problems:

• Gas in the big line would be under high pressure, and that pressure must be reduced.

see FAIRBANKS ENERGY page 17

Prudhoe to Valdez – big pipeline

Tariff per million Btu	$2.96 to $3.85*
Kind of gas	Wet gas**
Pipeline volume	2.7 billion cubic feet/day
Notes: Includes initial treatment at Prudhoe Bay	

Source: TransCanada/ExxonMobil, 2010

Prudhoe to Big Lake – small pipeline

Tariff per million Btu	$7.75
Kind of gas	Wet gas**
Pipeline volume	500 million cubic feet/day
Notes: Includes initial treatment at Prudhoe Bay; tariff is rough estimate that could be 30% higher or lower depending on construction costs	

Source: Alaska Gasline Development Corp., 2011

Prudhoe to Fairbanks – big pipeline

Tariff per million Btu	$2.59 to $3.37*
Kind of gas	Wet gas**
Pipeline volume	2.7 billion cubic feet/day
Notes: Includes initial treatment at Prudhoe Bay	

Source: TransCanada/ExxonMobil, 2010

Prudhoe to Fairbanks – small pipeline

Tariff per million Btu	$8.99
Kind of gas	Wet gas**
Pipeline volume	500 million cubic feet/day
Notes: Includes initial treatment at Prudhoe Bay; tariff is rough estimate that could be 30% higher or lower depending on construction costs	

Source: Alaska Gasline Development Corp., 2011

* Tariff varies based on length of contract and volume shipped; range shown is for 20- and 25-year negotiated contracts.

** Wet gas includes methane plus such gas liquids as propane and butane.

Note: Tariffs do not include costs charged by gas producer or local gas utility.

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FAIRBANKS ENERGY

• Gas in the big line would contain a blend of ethane, propane, butane and other natural gas liquids besides the main component, methane, which is the gas burned in furnaces.

Gas in the big pipeline would be compressed to a potent 2,500 pounds per square inch, or psi, to propel the molecules through the pipe.

But methane when it passes a home's gas meter is pressurized to as little as a lazy quarter-pound psi, less than the pressure exerted when a child blows bubbles into a glass of milk through a straw.

So a lot of decompressing needs to happen along the way.

Much of the decompression would occur at the straddle plant.

This plant also would extract propane and other liquids so that just methane would flow toward the Fairbanks users. The extracted liquids then would get reinjected into the main pipeline flow, unless an industry sprouted there that could process and sell the liquids.

The Alaska Gasline Development Corp. in July 2011 estimated that a straddle plant would cost about $210 million.

The plant likely would be located well outside of where most Fairbanks residents live. Development is restricted in the Fairbanks core because of poor air quality, especially during winter's cold-weather inversions as oil, coal and even wood are burned for fuel.

Cleaner air would be a welcome bonus of piping natural gas to Fairbanks. The February 2012 Northern Economics preliminary report says widespread use of natural gas rather than oil or coal would cleanse Fairbanks air now dirtied by particulate matter — soot, smoke and such — as well as carbon monoxide, nitrogen oxide and sulfur dioxide.

$60 million

This is a rough cost estimate for a 35-mile pipeline connecting the straddle plant to town.

The estimate also comes from the July 2011 Alaska Gasline Development Corp. report. The report said the gas would be pressurized at 1,400 psi within a 12-inch-diameter pipe.

$309 million to $662 million

This is the estimated cost range for a pipeline network within Fairbanks.

The Northern Economics preliminary study figured Fairbanks would need 111 miles of 8- to 10-inch transmission pipe, 118 miles of 6-inch feeder lines, 804 miles of 2-inch distribution lines and 325 miles of 5/8-inch to 1-inch service lines (the smaller diameter for houses, the larger for businesses).

Fairbanks also would need nine pressure-regulating stations – stops along the pipeline network where the gas pressure gets reduced.

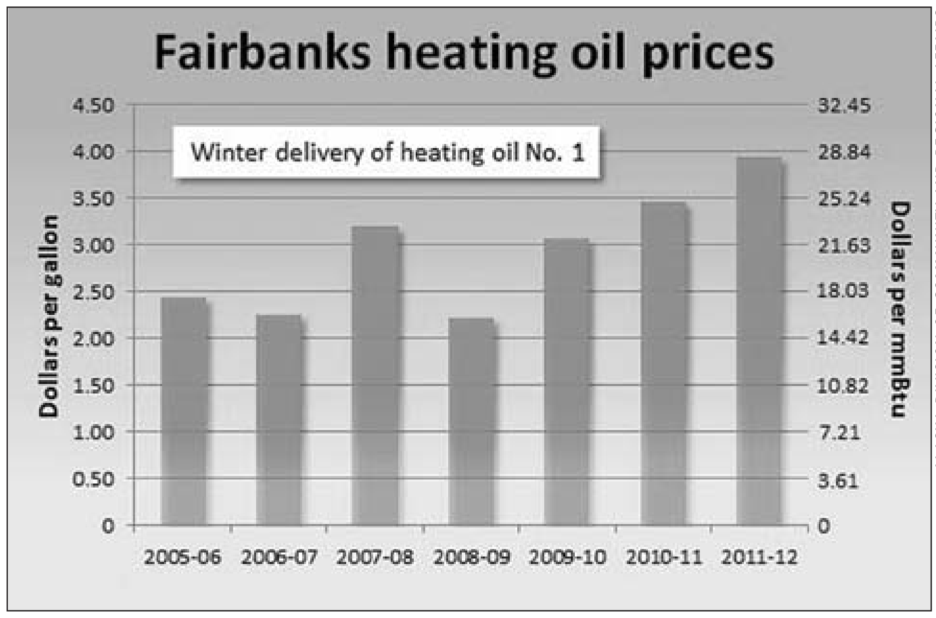
Separately, Fairbanks residents would need to convert their homes and businesses to gas systems. This would be expensive, too.

$25 million to $200 million or more?

This is a cost range for converting Fairbanks home water heating and furnace systems to natural gas. To be blunt about it: The wide range reflects imprecise cost estimates.

For hot-water boilers, Fairbanks Natural Gas, the local gas utility that trucks in LNG from the Cook Inlet area, estimates converting an oil-fired gun to a gas-fired gun costs $1,000 to $1,500.

The National Energy Technology Laboratory in 2006 pegged the cost in Fairbanks at $1,400 for replacing the burner to $3,000 for replacing the entire unit.



ALASKA DIVISION OF COMMUNITY AND REGIONAL AFFAIRS

Changing out furnaces could be more pricey. The 2012 preliminary Northern Economics study estimated the furnace replacement cost at $8,000 to $15,000, depending on the extent of work needed. The authors said they will refine their cost estimates in their final report later this year, and they're still investigating the cost of commercial-building conversions.

What price for Fairbanks gas?

It's unclear how much delivered gas would cost Fairbanks consumers.

The 2012 Northern Economics preliminary study said, "It is too soon to develop preliminary distribution costs. ... As the project evolves, the number of miles of pipeline and prospective connections per segment will generate preliminary distribution costs."

If the delivered cost could be slashed to $14 per million Btu through mass conversions to gas heating, economies of scale and other efficiencies, the average household savings would approach $2,600 a year, the study found.

Among other variables, the cost would depend on who paid for the infrastructure, how many customers signed up, where they live and how quickly gas became the fuel of choice in Fairbanks.

There's some sentiment in Fairbanks to ask the state for money to build a local gas pipeline network. Separately, the Alaska Legislature has considered a measure to create a state loan fund to help Fairbanks homeowners convert their heating systems to natural gas. ●

Please see part 1 of this story in the May 6 issue and part 3 in the May 20 issue.

Editor's note: This is a reprint from the Office of the Federal Coordinator, Alaska Natural Gas Transportation Projects, online at www.arcticgas.gov/challenges-distributing-north-slope-gas-alaskans.

EXPLORATION & PRODUCTION

Red Wolf exploration well comes up dry

The Red Wolf No. 2 exploration well in the eastern North Slope's Badami unit was "a dry hole," operator Savant Alaska's president told Petroleum News May 8.

"The well was a dry hole. … our target zone was wet (contained water)," Greg Vigil said.

Red Wolf No. 2 targeted the Kekiktuk formation, which contains the oil reservoir for the Endicott field, west of Badami. The Kekiktuk is a deeper formation than the Brookian, where previous Badami development occurred.

Savant drilled the B1-38 well into the Red Wolf prospect in early 2010 and found oil in two horizons: the Kekiktuk and the shallower late Cretaceous Killian sands. Although Red Wolf is still an exploration prospect, it is currently producing from the Killian.

Red Wolf No. 2 was about two miles northwest of the bottom hole for B1-38.

Savant is on an ongoing mission to improve production rates at Badami, which has been shut down and restarted numerous times since startup in 1998.

Alaska Oil and Gas Conservation Commission figures for March show 1,197 barrels of oil per day from Badami, an increase of 8 percent from February.

In addition to drilling Red Wolf No. 2, this past winter Savant did workovers in the B1-16 and B1-21 wells, installing gas lift to be able to produce the wells to the Badami plant.

The company has already started planning next winter's drilling program, Vigil said.

—KAY CASHMAN

● LAND & LEASING

Great Bear divides North Slope holdings

Eni hands over Mustang prospect leases to Alaska Venture Capital Group, numerous small deals approved in March, April

By ERIC LIDJI
For Petroleum News

Great Bear Petroleum LLC formed a number of affiliates earlier this year to manage its massive North Slope land holdings, according to recent state leasing reports.

The Alaska independent transferred complete working interest and sizable royalty interests — between 83 and 87 percent — in its North Slope acreage to two companies: Great Bear Petroleum Ventures I, LLC and Great Bear Petroleum Ventures II, LLC.

Great Bear Petroleum Ventures I now holds 126,186 onshore acres and Great Bear Petroleum Ventures II now holds 372,856 onshore acres, according to state lease records.

Great Bear Petroleum formed four affiliates on March 12. The first, a holding company called Great Bear Petroleum Operating LLC, is the owner of the other three: Great Bear Petroleum Ventures I, Great Bear Petroleum Ventures II and Great Bear Petroleum Ventures III. Currently, Great Bear Petroleum Ventures III holds no acreage.

Alaska statues limit the amount of acreage a single entity can hold in the state.

Eni Petroleum US LLC transferred its remaining 20 percent working interest and 16 percent royalty interest in six North Slope leases in and around the Southern Miluveach unit to Alaska Venture Capital Group LLC. The Italian major originally retained the interest when it farmed-out the North Tarn prospect to the company in January 2010.

Through its operating arm Brooks Range Petroleum Corp., AVCG and its partners recently announced a 40 million barrel discovery at the prospect, now called Mustang.

Southern Miluveach sits on the southwestern boundary of the Kuparuk River unit.

Union Energy (Alaska) LLC transferred 100 percent working interest and 81.25 percent royalty interest in two foothills leases — ADL 391326 and ADL 391327 — to Auxillium Alaska Inc. A man named Frank J. Hariton incorporated Auxillium in August 2011.

BP Exploration (Alaska) Inc. transferred a minor royalty interest in three leases at the Milne Point unit — ADL 047433, ADL 047437 and ADL 047438 — to Black Stone Acquisitions Partners I, LP, an arm of the global investment firm. BP also allowed three Beaufort Sea leases to expire — ADL 391469, ADL 390836 and ADL 390828.

Five corporate and independent investors transferred varying interests in four Oooguruk unit leases — ADL 355036, ADL 355037, ADL 355038 and ADL 355039 — to operator Pioneer Natural Resources Alaska, Inc. The entities include Anadarko Petroleum Corp., Oxy USA Inc., XH LLC, Herbaly Exploration LLC and George Alan Joyce Jr.

Bill Armstrong, president of Armstrong Oil & Gas, transferred a small royalty interest — all less than 0.1 percent — in numerous North Slope leases to Jeffery A. Lyslo.

The state also finalized leasing activity related to the Point Thomson unit settlement.

In Cook Inlet, the Victor Wynden LP transferred a small royalty interest in three leases at the Redoubt unit to independent investor Victor Rogers. The interests were all less than 0.03 percent. The leases were ADL 381003, ADL 381201 and ADL 381203.

The Alaska Division of Oil and Gas denied the transfer of small to moderate royalty interests in seven leases contiguous to the Kitchen Lights unit to Escopeta Oil Co. LLC.

The four entities requesting to transfer interests were A. Lawrence Berry (0.984375 percent), Danny S. Davis (0.859375 percent), Taylor Minerals LLC (0.65625 percent) and Escopeta Oil of Alaska LLC (10 percent). The leases were ADL 391598, ADL 391599, ADL 391603, ADL 391604, ADL 391605, ADL 391606 and ADL 391607.

Cornucopia Oil & Gas LLC transferred a 1 percent working interest and 0.75 percent royalty interest in 30 leases at Kitchen Lights to operator Furie Operating Alaska LLC.

Annette Troseth transferred a small royalty interest in five leases in an around the Nicolai Creek unit to Gregory Scott Pfoff, president of unit operator Aurora Exploration. ●

Contact Eric Lidji at ericlidji@mac.com

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GREAT BEAR

be today. Because quite frankly we are working very, very hard across the board with some very smart people internally and close to us consultants to say, 'look we can move this cost significantly by doing things this way,' and 'maybe doing things this way will require the state to help us' … 'maybe in a regulatory way to become more efficient' — again, that's not Great Bear exclusively but the industry as a whole."

A more conservative Duncan

Although clearly pleased at the thought of spudding his first well in late May or early June, nonetheless in his April 25 presentation of Great Bear's plans and expectations Duncan talked in terms of the company's play being "drilled out at a very high rate for at least the next 10 or 15 years, maybe longer" with 200 wells per year for a total of 3,000 wells," as compared to previous presentations where three consecutive drill-outs totaling 9,000 wells were proposed.

Also, in his recent presentation Duncan went into more detail about the geologic risk of the North Slope's three major source rocks, the HRZ/GRZ, Kingak and Shublik than he has in the past.

While emphasizing the three source rocks were very well known, "there is a modeled outcome based on the dominance of oil, natural gas liquids, gas-phased production that has a huge impact on the commercial outcome. If the rocks are too ductile, if they're too plastic, too play-rich, too gooey to frac well, that could cause a significant challenge that could be terminal to certain portions of the play early on."

But, he said, the problem was "not necessarily long-term," his inherent optimism back in place.

"Technology is evolving very, very rapidly. I am a great believer that if we put the challenge out to the Halliburtons, the Schlumbergers, the Baker Hughes, the Weatherfords and the others of the world, that it'll get cracked — the code will get cracked. Whether today, next year, or subsequent, I am a great believer in that," Duncan said, noting that geologic risk would be addressed "very early on" in Great Bear's work program.

Duncan: State could help with sand

Challenges to source rock exploitation have been compiled by the state Division of Oil and Gas' shale task force, Duncan said, having composed a list of them with his response to each in blue in the Slide 6 he used in his April Senate Resources Committee presentation (see adjacent graphic titled North Alaska Shale Resource Play Realization: Challenges and Business Development Opportunities).

The items that "appear to be hot buttons in the discussion," Duncan said, are as follows:

- Access to gravel for infrastructure support.
- Water for supporting the work force in the context of drinking water, but also frac water used in the stimulations.
- Developing an in-state supply of proppant for hydraulic fracturing operations.

Proppant, Duncan said, is "sand, silica rich sand." Something, "in a state this size with the big rivers and mountain belts and things of that nature, the mining operations that have gone on in this state for years, my expectation is that, with time, we'll sort out an in-state supply of proppant, or silica rich sand. It's something we are working on right now, but the state certainly could facilitate that, too.

Mother Nature's gift of water

Sen. Bill Wielechowski asked Duncan to "talk a little bit about fracking, where you intend to get the water, whether you foresee problems with the fracking here in Alaska impacting the aquifers or causing other environmental problems."

Wielechowski also asked whether Great Bear was looking at using propane instead of water in fracking operations.

"Water's a big one," Duncan replied. "There's little doubt that the public outcry in certain regions of the U.S., the need for better oversight of the industry in all of these operations, (has been) clearly played out in newspapers over the last couple of years. For Alaska, we have a number of gifts that are provided us by Mother Nature on the North Slope."

"There is, to my knowledge, virtually no fresh water aquifers that are not frozen as permafrost on the North Slope of Alaska," he said. "The water sources that we see as potentially available to us regionally lie subsurface between the base of the permafrost and depth of about 5,000 feet. There are very thick, regionally extensive, sandstone aquifers that contain, predominantly, brackish waters — saline water that has a salinity that is not acceptable for human consumption (and) agricultural use, if that was ever an issue on the Slope, but serendipitously, chemically very suitable for fracking.

"There's very active research on, in the direction of making or providing, seawater as an allowable component for frac make-up. Obviously if that bit of research is successful then there isn't a shortage of water that would be suitable for fracking operations.

"The operation of fracture stimulating a well and flowing it back and testing it for commercial production involves capture of the flowback water. The water that you pumped into the subsurface, as well any water that comes back out of it as part of post-frac operations; that water is captured and cleaned," Duncan said.

"We expect, as I think most of the industry now, that recycling operations and technologies of captured water for flowback operations will become very prevalent. I know that our current venture partner Halliburton (is) very actively involved in that kind of research of using filtering, actually reverse osmosis filtering, in part of flowback water before it's reinjected and then the captured chemicals that are oftentimes naturally occurring, that flow back with the flowback water are disposed of appropriately."

"So for our operations in North Alaska we don't see shallow aquifers as being a significant challenge. We believe that water supply regionally through the subsurface aquifers is something that ultimately will be extremely valuable to the players that are exploiting this play," he said.

But access to gravel is another issue, Duncan said.

"We see challenges with access to gravel, perhaps being one that we're going to need help with. There's plenty of gravel around but we have to access gravel in an appropriate and reasonable way. So that's certainly something we need to work on."

"As far as propane fracking is concerned, that's not part of our plan at this point," he said.

Level of activity

Wielechowski also asked the amount of activity that could be generated by Great Bear's development program; specifically the number of wells that would be drilled.

Referring to an article he'd recently read, Wielechowski said, "a shale well may initially produce oil at a high rate, perhaps a 1,000 barrels a day, (but) production tends to decline rapidly … stabilizing at a long-term rate of maybe 100 to 200 barrels a day. It goes on to say that in the Bakken play of North Dakota, for example, total production from the play (at the time) was running at about 488,000 barrels a day from 6,000 wells, indicating an average daily well production of just 80 barrels. Could you comment on what that would mean — the number of wells you would need to drill to fully commercialize the shale development that you're looking at?"

Duncan said, "It's our expectation that a well spacing in North Alaska will ultimately be somewhere around 160 acres per well" with 200 new wells and eight pads per year. … If we're trying to develop the Shublik, the Kingak and the HRZ all at the same time it portends a significant number of wells."

Great Bear's focus, he said, "in addition to getting an effective test of the play, is also to focus on reducing surface footprint and have more things going on under the ground with pipe than above the ground with wellheads and things of that nature. So 200 wells a year, which is less than the number drilled per month in the Eagle Ford will support an operation here that goes well past my career and probably most of the folks in this room, in fact," Duncan said. ●

Contact Kay Cashman at publisher@petroleumnews.com

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AEDC FORECAST

Petroleum News and compiled by AEDC.

This highly anticipated event drew more a hundred business professionals again this year.

AEDC also released its 2011 Annual Report focusing on its accomplishments and projects from 2011.

Both reports and AEDC Connections 2nd Edition Digital Newsletter, Live. Work. Play., went paperless — i.e. digital — this year.

They can all be found at AEDC's website at www.aedcweb.com/

—PETROLEUM NEWS

Petroleum news

Oil Patch Bits

ASCE invites participants to the 2012 symposium

The ASCE said April 25 that it is requesting a call for papers for the upcoming 10th International Symposium on Cold Regions Development in Anchorage, Alaska, June 2-5, 2013.

The Technical Council on Cold Regions Engineering of the American Society of Civil Engineers and the Alaska Section of ASCE will sponsor the ASCE 10th International Symposium on Cold Regions Development in Anchorage at the Dena'ina Civic and Convention Center.

The symposium theme is "Planning for Sustainable Cold Regions." You are invited to submit paper abstracts and session proposals online at http://content.asce.org/conferences/coldregions2013/index.html. Authors are expected to orally present their papers in a technical session or poster session. Deadline for abstracts and or papers is June 20, 2012. Papers and poster presentations are encouraged on all aspects of cold regions engineering and development, including: frozen ground and permafrost; building design; construction techniques; oil and gas; structure and foundation failures; water and wastewater systems, and much more. For information, please contact Steering Committee Co-Chairs Thomas G. Krzewinski at tkrzewinski@golder.com, or Jon E. Zufelt at jon.e.zufelt@usace.army.mil.

Harvey Gulf and Shell Vessel winner tours New Orleans

COURTESY SHELL

Shell said April 18 that Rita Ramoth, winner of the Harvey Gulf International Marine and Shell Vessel naming competition, was accompanied by her Aunt Janet Mitchell and Shell Communications Specialist Michelle Malerich for a three day trip to New Orleans including a tour of the city and of the vessel "Sisuaq" on April 9.

Shell and Harvey Gulf International Marine held a vessel naming competition throughout the Northwest Arctic Borough in December of 2011. Ramoth won with her submission of "Sisuaq," the Inupiat word for beluga. Along with a $5,000 dollar grant to the Inupiat language and culture program and a $500 dollar gift card to the local store, Ramoth was also given an all expenses paid trip to New Orleans.

During Ramoth's visit, she and her aunt experienced the French Quarter, the Audubon Zoo and Aquarium, the French Market, participated in a Swamp Tour, witnessed the beauty of the Mississippi River and sampled plenty of local

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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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PARNELL Q&A

Sen. Paskvan appeared not to trust the Legislature's own consultants, when PFC Energy's work actually agreed with our administration's position.

There's no sense in us putting forward our experts when the Legislature already had its experts testifying the way they were.

Petroleum News: If Gaffney Cline had testified to the Legislature, what would they have told lawmakers?

Parnell: I don't know. I'm not going to make assumptions or speculate because I don't know what the questions would be. I can just tell you that we set forth a proposal that was in Alaska's interest to develop existing fields and new fields.

Petroleum News: Did Gaffney Cline help draft the legislation?

Parnell: I worked directly with the commissioner and deputy commissioner on it. I do not know exactly what occurred within the Department of Revenue. Literally, they had two years of working together. So I don't know exactly when and where those communications happened.

Petroleum News: How do you respond to charges from people like Senate President Gary Stevens that your administration couldn't adequately defend the proposal?

Parnell: I think that notion was simply nonsense. What the senator is failing to tell you is they could not get 11 votes within the Senate for a comprehensive change to bring about an increase in oil production.

We had hundreds if not thousands of people who testified, sent messages, and whose livelihood in our state depends upon more work in the oil patch. To say that we can maintain ourselves and that everything is fine while we're experiencing this production decline really is a slap in the face to Alaskans who want to work, who want to grow this economy, and who depend upon oil and gas.

And it's not just oilfield workers — it's restaurant owners, office supply store workers, realtors, auto dealers and their employees. We are all dependent upon this industry.

I will continue to do everything I can to assure that we grow production and grow Alaskan opportunity rather than saying that status quo decline is fine.

Petroleum News: Sen. Bert Stedman, one of the Finance Committee co-chairs, claimed there was widespread agreement the tax doesn't work at very high oil prices. Did you consider just focusing on that?

Parnell: We did, and therein lies the rub. Because we could only get to 10 votes in the Senate. It was split down party lines. Ten Republicans were willing to engage in that discussion and vote for change. Ten Democrats were not. That's the raw truth of what happened there.

Petroleum News: Well, I'm guessing this issue won't go away.

Parnell: Not as long as production decline continues.

Petroleum News: What's your next step?

Parnell: I'm going to continue working to convince a few more senators that production decline is not fine, that we can pull new oil from existing fields with tax changes, and work these issues again in 2013.

Petroleum News: Will you try a different proposal or just hope that a new Legislature sees things differently?

Parnell: It's too early to tell now. I'll be making those decisions in November, December. That's when I put in my legislative package of bills.

Petroleum News: Does the difficulty settling on an oil tax affect the gas line project in any way?

Parnell: It very well could. The Legislature is not structured to take up both oil tax terms and gas tax terms related to a pipeline in the same session. Those are two weighty issues that require a lot of time and effort, and we're likely going to have to choose one or the other to take up in 2013.

Petroleum News: About Point Thomson, former Oil and Gas Division director Mark Myers criticized your administration for giving up too much control in the settlement with Exxon Mobil. How do you respond to his critique?

Parnell: The attorney general, the commissioner of natural resources, and I all firmly believe that the state resolved the Point Thomson litigation in the state's interest, for a number of reasons.

First, it maximizes development of Alaska's resources for Alaskans. We obtained solid work commitments requiring billions of dollars of spend by these companies. If they don't meet those work commitments, the companies lose acreage at the unit.

Second, the settlement will provide jobs for Alaskans now and into the future. Third, it brings us closer to a major gas line. And fourth, it resolves a case that has already been going on for seven years and by all estimations could have gone another 10-15 years.

Everything in this settlement was measured and weighed with Alaskans' interests in mind. Frankly, this settlement is pointed at getting Alaskans a major gas line.

Petroleum News: Does the language specifically require Exxon to complete its gas cycling project?

Parnell: I'm going to point you to our department personnel on that.

Mark Myers was arguing to delay any major gas sale in favor of what's called full-field cycling. The information he was relying on, from a 2008 PetroTel study, has since been updated, both by PetroTel and by DNR, with a more realistic view of Point Thomson's reservoir performance. Full-field cycling, as he's urged, is simply not a viable option.

The choice in the settlement was really between the initial production system and continued litigation, as well as balancing our interest as a state in getting to a major gas sale. ●

Contact Stefan Milkowski at stefanmilkowski@gmail.com

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OIL PATCH BITS

Cajun cuisine, including beignets from the infamous Café Du Monde. They also met and dined with several Harvey Gulf and Shell employees.

The trip concluded with an escorted tour of the Harvey Gulf's New Orleans office and of the "Sisuaq" by Harvey Gulf President Robert L. Guinn III, where Ramoth signed her name on one of the vessel doors, and box seats to an NBA game, courtesy of Harvey Gulf.

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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NUNA DISCOVERY

produces from the Nuiqsut and Kuparuk formations at Oooguruk, essentially every well in the unit passes through the Torok.

Three laterals in test

In a recent pilot project to test the potential of the Torok, Pioneer drilled three lateral wells from its existing gravel island at Oooguruk and the directional Nuna No. 1 well starting on ADL 25528, some 2.5 miles northwest of Kuparuk River unit drill site 3S.

The Torok formation would underpin the Nuna development that Pioneer proposed for the region last year and recently revised in an updated plan of operations for its leases.

As outlined, Pioneer would drill between 35 and 65 horizontal wells from two onshore pads, primarily targeting the Torok but also possibly the Kuparuk, Nuiqsut and Ivishak.

Under the terms of its recent expansion of the Oooguruk unit to include its Nuna area leases, Pioneer must decide by June 30, 2014 whether or not it will sanction the project.

When the state approved the Torok participating area at Oooguruk last summer, Pioneer estimated area contained 690 million barrels of original oil in place and said it could recover as much as 25 percent using primary and enhanced recovery techniques.

Sikumi non-commercial

While Nuna No. 1 appears to be a success, Pioneer wasn't as fortunate on its other exploration well this winter, the offshore Sikumi No. 1 two miles southwest of Oooguruk.

A "deep test" of the Ivishak formation was wet and although the well encountered some gas another zone, it was "basically non-commercial," Dove said. Pioneer plugged and abandoned Sikumi No. 1 and wrote down a $19 million loss for the unsuccessful well.

The exploration wells cost Pioneer slightly more than $50 million, combined. Pioneer budgeted $135 million of its $2.4 billion drilling program this year to activities in Alaska.

Pioneer holds a 100 percent working interest in the Nuna No. 1 well and a 70 percent in the Nuiqsut development well with the remaining 30 percent held by Eni Petroleum.

While the company used two rigs to conduct its exploration and development campaigns this winter, activity continues through the summer with one rig on the Oooguruk gravel island in Harrison Bay currently drilling into the Kuparuk, Nuiqsut and Torok formations.

Nuiqsut test successful

Pioneer is also reporting success from its development efforts.

Using a "plug and perf" completion technique borrowed from its Eagle Ford Shale operations, a development well Pioneer drilled into the Nuiqsut formation produced at an initial rate of 4,000 barrels per day, making it "by far our best Nuiqsut well," Dove said, adding that the results suggested the technique could be used on other Nuiqsut wells.

The "plug and perf" method, also known as a "mechanical diversion" fracturing system, is thought to be more effective because it can stimulate a larger portion of a reservoir.

If the well continues to produce near its initial levels, it could have a substantial impact on production rates at Oooguruk and could make Alaska more attractive to Pioneer.

Pioneer produced 4,000 barrels per day from Alaska in the first quarter, flat from the fourth quarter of 2011 and down from 5,000 barrels per day in the first quarter of 2011.

Companywide, Pioneer produced 147,000 barrels per day in the first three months of the year, a 37 percent increase year over year attributable largely to the growth of three unconventional plays in Texas: the Spraberry, Eagle Ford and the Barnett Shale Combo.

Staying put in Alaska?

Analysts have wondered whether Alaska is a divestment candidate for the company as it continues to grow its unconventional oil production in Texas and the midcontinent.

When asked last August about the future of its Alaska and South Africa assets, CEO Scott Sheffield said "it's always an option in regard to whether or not to look at divesting those two assets," but said he saw South Africa as "running out" and Alaska as "growing significantly over the next several years." Pioneer recently sold its South Africa assets to the national oil company Petroleum Oil and Gas Corporation of South Africa (PetroSA).

When asked again recently about the future of Alaska, Sheffield said the decision would be made "down the road" but noted that Oooguruk production has been flat or declining for a year. "If the team up there can show us they have huge potential to grow production and frac several more Nuiqsut wells and look at some Torok, then we'll look at keeping and keep growing it," he said. "And so that's the key: Do we have enough upside on growth to able to reinvest the cash flow and grow the asset. And we love growing assets." ●

Contact Eric Lidji at ericlidji@mac.com

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NORDAQ WELLS

NordAq's president, Bob Warthen, told Petroleum News May 10. The plan is to drill first at Tiger Eye Central, probably later in this summer once all the permits are in place, Warthen said.

NordAq Energy Inc. has submitted an oil spill prevention and response plan for both wells to the Alaska Department of Environmental Conservation. According to this plan the drilling will be conducted from two separate gravel drilling pads, with each pad connected by a temporary gravel road less than three miles long to an existing lease road along the coast — the prospect area, situated in two state leases, is close to the existing Trading Bay and West McArthur River oil and gas facilities on the Cook Inlet coast.

Directional drilling

Directional drilling will be required at each location, with the North pad well involving extended reach drilling and requiring a drilling rig that is suitable for that type of drilling operation. Warthen said that NordAq is still working out which rig or rigs to use.

Both wells will be drilled to a depth of about 12,000 feet, targeting "oil-bearing zones within the Tyonek and Hemlock formations," NordAq's spill response plan says. The drilling of each well will take about 45 days, with well testing taking another 10 to 30 days, the plan says.

The plan of operations for Tiger Eye North said that the company is seeking both oil and natural gas.

According to a spacing exception

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HILCORP

have to get the service industry moving with us."

The problem is that the service industry needs to know its crews will be working day in and day out on "continuous drilling programs," which will allow both the service industry and Hilcorp to be more efficient.

Urgency is one of Hilcorp's core values, Barnes said, noting he'd recently told his managers that if their plates were full now, they'd better get platters, because things would get busier.

The same would apply to the service industry, he said.

Increasing production the goal

Houston-based Hilcorp Energy Co. is the "third largest privately held oil and gas producer in the United States," giving it the financial strength to do the work that needs doing on the Chevron Cook Inlet assets it acquired last year and on the Marathon Cook Inlet assets it is in the process of acquiring, Barnes said.

The focus is not on new drilling: In all its operations Hilcorp drilled 60 new wells last year; but it did 1,500 workovers.

"That's the hard work to get production going," he said.

He told RCA commissioners clearly concerned about declining Cook Inlet natural gas production that Hilcorp's production in the Lower 48 has gone up year after year.

"And it goes up because of hard work and capital being spent in existing legacy assets. That's one opportunity that exists in the inlet; that's one that we are choosing to pursue primarily.

"I can't probably overemphasize the amount of work that's actually required to try to take the risk and spend money and try to improve recovery from these fields," Barnes told the commissioners.

Offshore drilling

Hilcorp has a "derricks' down" project under way, with derricks being taken off three platforms in the Trading Bay unit and from the Granite Point platform.

Those derricks were old technology, he told the Alliance audience.

"One way or another we're going to get a modern drilling rig here," whether Hilcorp builds it or someone else builds it. It's similar to the model Marathon used,

> *"We are not a company that will be performing lots of big projects: We make our living through lots of small projects and ... working every wellbore, every sand and seeing what's there."*
>
> **—John Barnes, Hilcorp senior vice president for Alaska**

he said, where you get a rig with modern technology and just knock out wells; Hilcorp will do the same thing with a workover unit, he said.

The company will also be drilling onshore.

Barnes told the Alliance it's embarrassing, but the company is excited about just running a workover rig in the Swanson River field. "That's how low the bar is," he said.

Drift River

Barnes said Hilcorp has a C-plan, an oil discharge prevention and contingency plan renewal, out for public comment which references work at the Drift River Terminal. The company plans to raise the berms protecting the tanks this summer and install some new ones, with a goal of storing oil at Drift River again.

Storage of oil stopped at Drift River due to activity at the Mount Redoubt volcano, but the berms around the tanks did what they were supposed to do and protected the tanks, Barnes said.

Hilcorp is working closely with the Department of Environmental Conservation on the C-plan, he said.

"It's very important to try to get that terminal open again so that you're allowed to manage your tanker traffic more effectively in the inlet," Barnes said. Right now oil has to be stored at production facilities where there is a finite amount of storage "and it can result in tankers being curtailed, production shut-in, when you run out of storage."

It's not the way Hilcorp wants to manage oil storage, he said.

In response to a question about an alternative for storage at Drift River, Barnes told the Alliance audience that there has been discussion about a subsea pipeline, but sizing it would be a problem.

Because Hilcorp intends to grow production, "I don't know how to size it yet," Barnes said.

It's the Goldilocks' problem, he said: You don't want it too small and you don't want it too large.

A subsea pipeline may be a consideration for the future, but Barnes said Hilcorp needs to "establish a track record of getting production up" so that it could better determine a pipe size for such a project.

Gas production down

Barnes showed the commission recent Cook Inlet natural gas production figures. From 2008 to 2011 production declined from more than 400 million cubic feet per day to just over 300 million last year, he said.

"That represents about a 23 percent decline and I think we're all aware that most majors have significantly slowed their spend in the Cook Inlet and that is not surprising because of this decline."

But others are coming into the inlet, he said, calling it "an opportunity for companies to come in and try to perform and make a business."

Different companies play to different strengths, Barnes said, mentioning Apache's large lease position and extensive exploration program.

"Hilcorp's strength is we acquire old assets," he said.

About half shut-in

The Marathon assets Hilcorp is acquiring include 157 wells, 75 producing and 74 shut-in.

"Hilcorp looks at those shut-in wells as assets," Barnes said. "We're very much about trying to stare into every well, every wellbore and look at every sand and maximize production from the assets that we're acquiring."

Marathon is exiting the Cook Inlet basin, and that was important for Hilcorp in the acquisition, Barnes said, because, "It's a chance for us to consolidate interests in legacy fields, which we believe present tremendous opportunities for additional work and additional development."

Barnes noted that McArthur River and Ninilchik represent about 50 percent of Marathon's production, and those are both fields in which Hilcorp already has an interest. Consolidation of ownership in fields which are late in life allows for commercial alignment which may not exist with multiple owners, he said.

Barnes said Hilcorp's long-range plan is "pretty simple: It's all hard work."

"You want to invest significant amounts of capital to exploit the assets that we will be acquiring and in in-fill drilling, recompletions and workovers and compression."

As for what Hilcorp will be doing in Cook Inlet, Barnes said, "We are not a company that will be performing lots of big projects: We make our living through lots of small projects and ... working every wellbore, every sand and seeing what's there." ●

Contact Kristen Nelson at knelson@petroleumnews.com

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NORDAQ WELLS

request submitted to the Alaska Oil and Gas Conservation Commission, the surface location of the Tiger Eye Central well will be 690 feet from the west line and 550 feet from the north line of section 19 of township 8 north, range 14 west, Seward Meridian. The bottom hole location will be 839 feet from the west line and 1433 feet from north line of section 24 of township 8 north, range 14 west, Seward Meridian. The well location is in State of Alaska lease ADL 391104.

Response services

NordAq is contracting with O'Brien's Response Management and Alaska Chadux Corp. for oil spill response services. The company says that in the unlikely event of a loss of well control it will call in Boots & Coots Well Control International for assistance. Oil spill prevention measures include careful well planning and design, as well as the use of blowout preventers on the wells. NordAq also says that it has access to well capping technology and could drill a relief well, should these response techniques prove necessary.

NordAq's oil spill response plan is available for public review and comment until June 1.

—ALAN BAILEY

Contact Alan Bailey at abailey@petroleumnews.com

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CHINA INVESTMENT

come to take some shares, as I say, to learn from Canada.

"We buy our resources, our energy, from other channels. There are a lot of channels. But we'll work on Canada's exports to China or oil and gas. That will happen in the next few years."

He said the investment to date is primarily directed at improving China's knowledge of developing unconventional resources and turning a profit.

Prime Minister Stephen Harper has pledged to turn Canada into a global energy superpower by diversifying exports of Canadian oil sands crude and LNG to Asia, but opposition to plans by Enbridge and Kinder Morgan to build pipeline from Alberta's oil sands to tanker terminals on the British Columbia coast has raised concerns about Harper's chances of achieving his goal.

However, on the first anniversary of his sweeping election victory, Harper said Canada must align itself with the economic winners of the world to ensure continuing prosperity.

"The financial and debt crisis of the past few years may not in many countries be a passing phenomenon," he said.

"World economic power and wealth are shifting in a way that is historic and we as Canadians must decide that we will be on the right side of that history."

Harper said the latest federal budget, which contained provisions to streamline regulatory approval of major energy projects, is aimed at sustaining a "vibrant, growing economy for all Canadians, while protecting our environment."

He said the government's economic plan looks at the bigger picture and focuses on the longer term.

Investment growth expected

The importance of winning over the Chinese was emphasized by Gordon Houlden, director of the University of Alberta's China Institute.

He said Chinese investment could grow ten-fold from the current level of C$20 billion over the next 10 years to 15 years.

Beijing-based lawyer Robert Kwauk of Blake, Cassels & Graydon, said that if Enbridge's Northern Gateway project is approved it is likely Chinese investments in Canada's energy sector will top the largest single deal so far, when Sinopec acquired ConocoPhillips' 9 percent stake in the Syncrude Canada oil sands consortium for C$4.65 billion.

"The ball is really in our court to get that pipeline built," he said.

Xu Xiaojie, a senior researcher at the Beijing-based Institute of World Economics and Politics, said China's firms want to profit by taking cheap Canadian gas and building LNG pipelines and export facilities and selling the LNG to Asian buyers — not just those in China — who are willing to pay eight times more than North American buyers.

He noted that the gap between supply and price in Asia is currently running as high as US$16 per million British thermal units. ●

Contact Gary Park through publisher@petroleumnews.com

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HORN RIVER

"For it to be developed more aggressively, it will need something like LNG or a big change in gas prices," he said.

An Imperial spokesman said it is too early to put a nameplate capacity, cost, location or timing for a project by his company, but indicated that Imperial might be open to linking up with other developers.

Oil-linked contract key

The numbers game in the LNG equation was also underscored by Steven Farris, chairman and chief executive officer of Apache, which is operator of the Kitimat LNG project, currently the larger of two schemes to obtain Canadian National Energy Board export permits.

But Farris told a conference call that obtaining an oil-linked contract will be critical to making the Kitimat project work for partners Apache, Encana and EOG Resources, who have backed away from previous indications that a corporate sanctioning decision would be made early this year.

Farris said the front-end engineering and design work is "pretty much done" and the partners are now in the "throes of negotiations for a tenant to underpin that development. But we're not there until we're there."

He also said efforts to clear a right of way for a pipeline and make progress toward constructing an LNG terminal are also needed before a final go-ahead can be given.

> *"In the Horn River, we are committed to sustained drilling activities that practically will never stop for the life of the development."*
> **—Imperial CEO Bruce March**

Farris said the most important missing piece is to have a memorandum of understanding "that is good enough on the sales side to take the project forward on an economic basis."

March noted that LNG developments based on shale gas feedstock "face higher technical and capital cost challenges than those being built in Qatar and Australia, which draw on big long-life conventional gas reserves."

"In the Horn River, we are committed to sustained drilling activities that practically will never stop for the life of the development," he said.

Mike Dawson, president of the Canadian Society of Unconventional Resources, suggested that even if it costs $10 to liquefy and ship one thousand cubic feet of gas, producers are banking on landed prices of $17-$18 per million British thermal units.

—GARY PARK

Contact Gary Park through publisher@petroleumnews.com

NWT sees LNG as option

The Northwest Territories government is open to supporting an LNG export project to develop Canada's stranded Arctic gas resources, said NWT Industry Minister David Ramsay.

He said that although his government prefers to build a pipeline down the Mackenzie River Valley to southern markets, LNG is not off the table.

That notion got support from the Aboriginal Pipeline Group, which could own one-third of a Mackenzie pipeline if it is able to secure matching gas supplies from outside the main gas owners group, led by Imperial Oil.

APG President Bob Reid told Reuters said his group is "absolutely" open to a route change for the pipeline to participate in an LNG project.

"We're not constrained by routing at all," he said. "But, at the moment, there's not a plan to … go from the Mackenzie Delta westward (to the North American coast)."

Reid said that could see Mackenzie gas moved to the Alaska coast.

"There is an obvious connection there, but it does have some challenges," he said, referring to any proposal that would require gas to be shipped across the Arctic National Wildlife Refuge.

Imperial Chief Executive Officer Bruce March was hesitant about using Mackenzie gas for world-scale LNG development.

"It is too early for us to comment on that today because we're still in the early stages of looking," he said.

Ramsay said that although the NWT supports the stalled Mackenzie Gas Project over all other options "we're willing to discuss any opportunities or options with anybody who's interested in developing our resources."

—GARY PARK