Petroleum news

Vol. 18, No. 5 • www.PetroleumNews.com | A weekly oil & gas newspaper based in Anchorage, Alaska | Week of February 3, 2013 • $2

page 4 Senate TAPS Throughput Committee focused on increasing production

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page 10 BNSF counts on 40% hike in oil cargo; set sights on "longer-term" prospects

Vol. 1, No. 20 • www.PetroleumNewsBakken.com | A semi-monthly newspaper for industry and government | February 3, 2013

QEP leads NDIC well, unit apps

VERN WHITTEN PHOTOGRAPHY

Recent winter shot shows oil wells on section line near Mandaree, N.D. Spacing unit and well applications to NDIC in January put QEP Resources in lead with up to 176 new wells in new and existing spacing units. Highest estimated expected ultimate recovery, or EUR, for combination Middle Bakken/Three Forks wells was claimed by QEP with 1.4 million barrels per well. Slawson Exploration came in first for Middle Bakken EURs at 750,000 barrels of oil. See story on page 3.

BLM North Dakota lease sale nets $11.4M; Slawson high bidder

Slawson Exploration was the top bidder at the U.S. Bureau of Land Management's North Dakota oil and gas lease auction on Jan. 30. The Wichita, Kan., independent offered the highest single-parcel bid of $1,596,000 for an 80-acre tract in Mountrail County, which was also the top per-acre bid, $19,500, at the sale.

BLM netted a total of $11,433,090 from the sale of 2,831.38 acres in 25 federal leases, 48 percent of which it has to share with the State of North Dakota.

The tracts were in the western North Dakota counties of Mountrail, Burke, Dunn, Williams, Stark and McKenzie, where oil companies have been successfully drilling horizontal wells

see LEASE SALE page 17

Hess Bakken output up by 87%; well costs, capex down by 30%

Bakken oil and gas production for Hess Corp. was 87 percent higher in 2012 than in 2011, while well drilling and completion costs were cut by more than 30 percent during 2012, from $13.4 million per well in the first quarter to $9 million in the fourth quarter.

In a Jan. 30 conference call with analysts, John B. Hess, chairman and chief executive officer, said North Dakota Bakken net production averaged 56,000 barrels of oil equivalent per day in 2012, and is likely to average between 64,000 and 70,000 boe per day in 2013.

see HESS OUTPUT page 18

Hess to keep Bakken assets

Although he is clear there are no "sacred cows" in the boardroom, Hess Corp.'s top executive says the company is keeping its Bakken assets despite pressure from minority shareholder Elliott Associates L.P. and its associated entity Elliott International Ltd. to sell them.

"We have transformed Hess into a predominantly exploration and production company, which is part of a multi-year strategy to grow shareholder value. This strategy is focused on developing lower risk, higher return assets such as those related to our leadership position in the Bakken oil shale of North Dakota."

In a Jan. 30 conference call with analysts, Hess said keep-

see HESS ASSETS page 19

LAND & LEASING

Judge rules for ND

District court decision on shore zone dispute favors State of North Dakota

By MIKE ELLERD

For Petroleum News Bakken

On Jan. 29, North Dakota District Judge David W. Nelson ruled in favor of the State of North Dakota in a suit filed by private interest holders against the state over ownership of mineral estates in the area between the ordinary high and low watermarks of navigable waterways in the state, commonly known as the "shore zone."

LANCE GAEBE

The ruling applied to two cases, one filed by Stanford Reep, a Williams County landowner, and the other filed by Brigham Oil and Gas, both of which argued that the mineral rights in the shore zone belong to the adjacent or "riparian" landowner. Nelson, however, ruled otherwise. "The Court concludes that it is the State of North Dakota — as part of its title to the beds of navigable waterways — that owns the minerals in the area between the ordinary high and low watermarks on these waterways, and that this public title excludes ownership and any proprietary interest by riparian landowners," Nelson said in his ruling.

North Dakota Land Commission Lance Gaebe said he was pleased with outcome. "Trust Lands

see ZONE RULING page 8

COMPANY UPDATE

Herculean reserve growth

CLR's Bakken proved reserves nearly double; overall annual output jumps 58%

By RAY TYSON

Petroleum News Bakken

Bakken pioneer Continental Resources Inc. saw its year-end 2012 proved reserves across all of its properties jump 54 percent to 785 million barrels of oil equivalent. Likewise, total annual production rocketed 58 percent from 2011 levels to 35.7 million boe.

HAROLD HAMM

However, of the 785 million boe in total year-end proved reserves, nearly three-quarters or 564 million boe are situated in the Bakken petroleum system. And that's almost double the proved reserves in the play at the end of 2011, the company reported.

"We continue to increase our concentration in high-value, high-growth, crude oil assets, especially in the Bakken," said Harold Hamm, Continental's chairman and chief executive officer.

Oklahoma-based Continental is the largest producer and leaseholder in the Bakken petroleum system of North Dakota and Montana, with roughly 1.1 million net acres.

With the 2012 increase in proved reserves, Continental has now grown its overall proved reserves at a staggering compound annual growth rate of 45 percent since year-end 2009.

Reserves valued at $13.3 billion

The company said its 2012 proved reserves had a

see RESERVE GROWTH page 20

MOVING HYDROCARBONS

Obama spreads XL jitters

Canadians worried US president won't honor Nebraska governor's decision

By GARY PARK

For Petroleum News Bakken

The Canadian government has suddenly turned edgy about hopes of seeing TransCanada's Keystone XL pipeline clearing its final regulatory hurdle and spreading fresh optimism among Alberta oil sands and Bakken producers.

Now that Nebraska Gov. Dave Heineman has sent a letter to President Barack Obama endorsing TransCanada's proposed rerouting of the pipeline to avoid the state's ecologically sensitive Sandhills region, the final verdict rests with the U.S. State Department which must issue a Presidential Permit

see XL JITTERS page 19

Hoeven, Baucus drive Keystone letter

U.S. Sens. John Hoeven, N.D., and Max Baucus, Mont., garnered the support of a bipartisan group of 53 U.S. senators in signing a Jan. 23 letter to President Obama urging the president to expedite approval of the Keystone XL pipeline on the heels of Nebraska Gov. Dave Heineman's recent endorsement of the pipeline following a favorable environmental review of the

see KEYSTONE LETTER page 19

Alaska pipeline teems with work to prevent spills, keep oil warm

The trans-Alaska oil pipeline is buzzing with activity. It's the fallout from an early 2011 spill at Pump Station 1 that forced extended shutdowns of the line and drew intense scrutiny from federal regulators.

The work, which involves rearranging station pipes and installing measures to help the pipeline better cope with extreme cold weather and cooling crude temperatures, approaches a budget of $200 million, Alyeska spokeswoman Michelle Egan told Petroleum News.

A "consent agreement" Alyeska signed with regulators is guiding the work. It's essentially a long to-do list stemming

see PIPELINE ACTIVITY page 13

Idemitsu, AltaGas enter LNG race

Add another name to the list of contenders to export LNG from Canada — a new joint venture and limited partnership by Japan's refining, manufacturing and products sales giant Idemitsu Kosan and fast-growing Canadian energy infrastructure company AltaGas.

If all goes according to plan they hope to start LNG shipments of 2 million metric tons a year as early as 2017 while adding 600,000-700,000 metric tons a year of LPG to the mix.

Although entering a crowded field, the partners believe they can use their combined strengths to exploit a "niche opportunity," said AltaGas Chief Financial Officer Debbie Stein.

The answers are expected to be known later this year for the LPG proposal and by early 2014 for LNG when they

see LNG RACE page 20

FINANCE & ECONOMY

$2.3B in Alaska

ConocoPhillips's 2012 earnings in state rise, but taxes double earnings

By ERIC LIDJI

For Petroleum News

ConocoPhillips Co. reported adjusted earnings of $2.3 billion from Alaska in 2012, up nearly 13 percent from $2 billion in 2011 despite falling production and higher spending.

The largest producer in Alaska paid $4.9 billion in state and federal obligations in 2012.

As has been the norm in recent years, ConocoPhillips' annual earnings come as state lawmakers are debating whether and how to change the fiscal system covering oil production in the state. And, as has also been the norm in recent years, the figures provide plenty of statistics to bolster arguments both for and against those revisions.

ConocoPhillips spent more in Alaska in 2012 than it did in 2011, but its investment in the state remains far below other regions in its portfolio and only a sliver of overall spending.

Earnings increased in 2012, but ConocoPhillips continues to shoulder a larger tax rate in Alaska than it does in some other regions. Capital spending in Alaska increased year-over-year, but the bump is largely attributable to ConocoPhillips sanctioning the CD-5 Alpine satellite in late 2011; ConocoPhillips is spending much less in Alaska than in its other seg-

see CONOCO EARNINGS page 19

NATURAL GAS

A certainty issue

DNR & utilities present different perspectives on Cook Inlet gas supplies

By ALAN BAILEY

Petroleum News

Amid concerns over the continuity of natural gas supplies for Southcentral gas and power utilities, apparent disconnects between statements by the Alaska Department of Natural Resources, or DNR, and the utilities about the abundance or otherwise of remaining gas in the Cook Inlet basin have created a sense of confusion for those who worry about the specter of an Alaska winter with inadequate energy supplies.

Residents of Southcentral Alaska depend on gas from aging gas fields in the basin for heating homes and other buildings, while about 90 percent of the region's electricity comes from gas-fueled power plants. Utilities say that, with production from those gas fields declining at around 16 percent per year, supplies are likely to run short around 2014-15, necessitating actions such as running some power generation on expensive diesel fuel or importing some natural gas from outside the region.

The core issues at stake seem to be the certainty that utilities need for gas supplies for their customers and the time required to bring new gas on line.

Frustration

The Alaska Legislature has held a series of

see GAS PERSPECTIVES page 17

FINANCE & ECONOMY

Competitiveness issue

Econ One: Parnell's bill would put Alaska back in running, benefit new players

By KRISTEN NELSON

Petroleum News

State revenues would drop under oil fiscal regime changes proposed by Alaska Gov. Sean Parnell, but investment in oil projects in the state would compare more favorably to opportunities available in similar areas in the Lower 48 and abroad.

And new participants, who fare worse than incumbents under the present tax system, would fare better than incumbents under the proposal.

Economist Barry Pulliam of Econ One Research told the Senate Special Committee on TAPS Throughput in a Jan. 24 background briefing on the tax proposal that the biggest changes are

Pulliam said the goal "was to have a government take that was competitive with what is available elsewhere and that range is generally viewed ... if you look at these other areas that are having success ... somewhere in that 60 to 65 percent range."

elimination of progressivity, capital credits and the state purchase of losses under the current production tax system, ACES, Alaska's Clear and Equitable Share.

The governor's proposal also contains a gross revenue exclusion to provide an incentive for

see OIL TAX BILL page 15

contents

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Alaska - Mackenzie Rig Report

The Alaska - Mackenzie Rig Report as of January 31, 2013.
Active drilling companies only listed.

TD = rigs equipped with top drive units WO = workover operations
CT = coiled tubing operation SCR = electric rig

This rig report was prepared by Marti Reeve

Alaska Rig Status

North Slope - Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Doyon Drilling			
Dreco 1250 UE	14 (SCR/TD)	Prudhoe Bay DS-07-34	BP
Dreco 1000 UE	16 (SCR/TD)	Milne Point MPG-15	BP
Dreco D2000 UEBD	19 (SCR/TD)	Alpine CD3-127	ConocoPhillips
AC Mobile	25	Prudhoe Bay Z-61	BP
OIME 2000	141 (SCR/TD)	Kuparuk 3K-105	ConocoPhillips
Kuukpik	5	Mobilizing to Umiat	Linc Energy Operations Inc.
Nabors Alaska Drilling			
Trans-ocean rig	CDR-1 (CT)	Prudhoe Bay	Stacked
AC Coil Hybrid	CDR-2	Kuparuk 3C-11	ConocoPhillips
Dreco 1000 UE	2-ES	Prudhoe Bay	Available
Mid-Continental U36A	3-S	Prudhoe Bay	Available
Oilwell 700 E	4-ES (SCR)	Prudhoe Bay	Available
Dreco 1000 UE	7-ES (SCR/TD)	Mobilizing to Colville River	Repsol
Dreco 1000 UE	9-ES (SCR/TD)	Prudhoe Bay	Available
Oilwell 2000 Hercules	14-E (SCR)	Prudhoe Bay	Available
Oilwell 2000 Hercules	16-E (SCR/TD)	Prudhoe Bay	Available
Oilwell 2000	17-E (SCR/TD)	Prudhoe Bay	Stacked
Emsco Electro-hoist -2	18-E (SCR)	Prudhoe Bay	Stacked
Emsco Electro-hoist Varco TDS3	22-E (SCR/TD)	Prudhoe Bay	Stacked
Emsco Electro-hoist	28-E (SCR)	Prudhoe Bay	Stacked
Emsco Electro-hoist Canrig 1050E	27-E (SCR-TD)	Kuparuk NDST-2	Pioneer Natural Resources
Oilwell 2000	33-E	Prudhoe Bay	Available
Academy AC electric Canrig	105-E (SCR-TD)	Mobilizing to Colvile River	Repsol
Nordic Calista Services			
Superior 700 UE	1 (SCR/CTD)	Prudhoe Bay Drill Site 5-35AL1	BP
Superior 700 UE	2 (SCR/CTD)	Prudhoe Bay Well Drill Site 6-22B	BP
Ideco 900	3 (SCR/TD)	Kuparuk Well 2T-08	ConocoPhillips
Parker Drilling Arctic Operating Inc.			
NOV ADS-10SD	272	Prudhoe Bay Acceptance meeting scheduled for Feb. 11, 2013	BP
NOV ADS-10SD	273	Prudhoe Bay DS 02-12D	BP

North Slope - Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
BP			
Top drive, supersized	Liberty rig	Inactive	BP
Nabors Alaska Drilling			
Commander 1500 HP	19-E (AC)	Oooguruk ODSN-24	Pioneer Natural Resources
OIME 2000	245-E	Oliktok Point	ENI
Doyon Drilling			
Sky Top Brewster NE-12	15	Spy Island SP22-FN1	ENI

Cook Inlet Basin – Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Kenai Land Ventures LLC (All American Consultants, labor Contract)			
Taylor	Glacier 1	Kenai Loop Drilling Pad #1	Buccaneer Energy Ltd
Aurora Well Service			
Franks 300 Srs. Explorer III	AWS 1	In winter maintantance mode through February	Hilcorp Alaska
Cook Inlet Energy			
Atlas Copco RD20	37	Beluga I-78	MGM Energy
Doyon Drilling			
TSM 7000	Arctic Fox #1	Swanson River 14B-27	Hilcorp Alaska LLC
Nabors Alaska Drilling			
Academy AC Electric CANRIG	99AC	Mobilizing to Colville River	Repsol
Continental Emsco E3000	273E	Kenai	Available
Franks	26	Kenai	Stacked
IDECO 2100 E	429E (SCR)	Stacked in Kenai	Available
Rigmaster 850	129	Kenai	Available
Academy AC electric Heli-Rig	106-E (SCR/TD)	Tiger Eye 1	NordAq

Cook Inlet Basin – Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
XTO Energy			
National 110	C (TD)	Idle	XTO
Spartan Drilling			
Baker Marine ILC-Skidoff, jack-up		Spartan 151 Upper Cook Inlet KLU#1	Furie
Cook Inlet Energy			
National 1320	35	Osprey Platform RU-1, workover	Cook Inlet Energy
Hilcorp Alaska LLC (Kuukpik, labor contract)			
		Steelhead Platform Well M-31, redrill, KD management Contract	Hilcorp Alaska LLC
	428	Anna Platform, preparing rig for drilling, KD Providing Labor	Hilcorp Alaska LLC
		Monopod Platform, Rig prep work, KD management contract	Hilcorp Alaska LLC

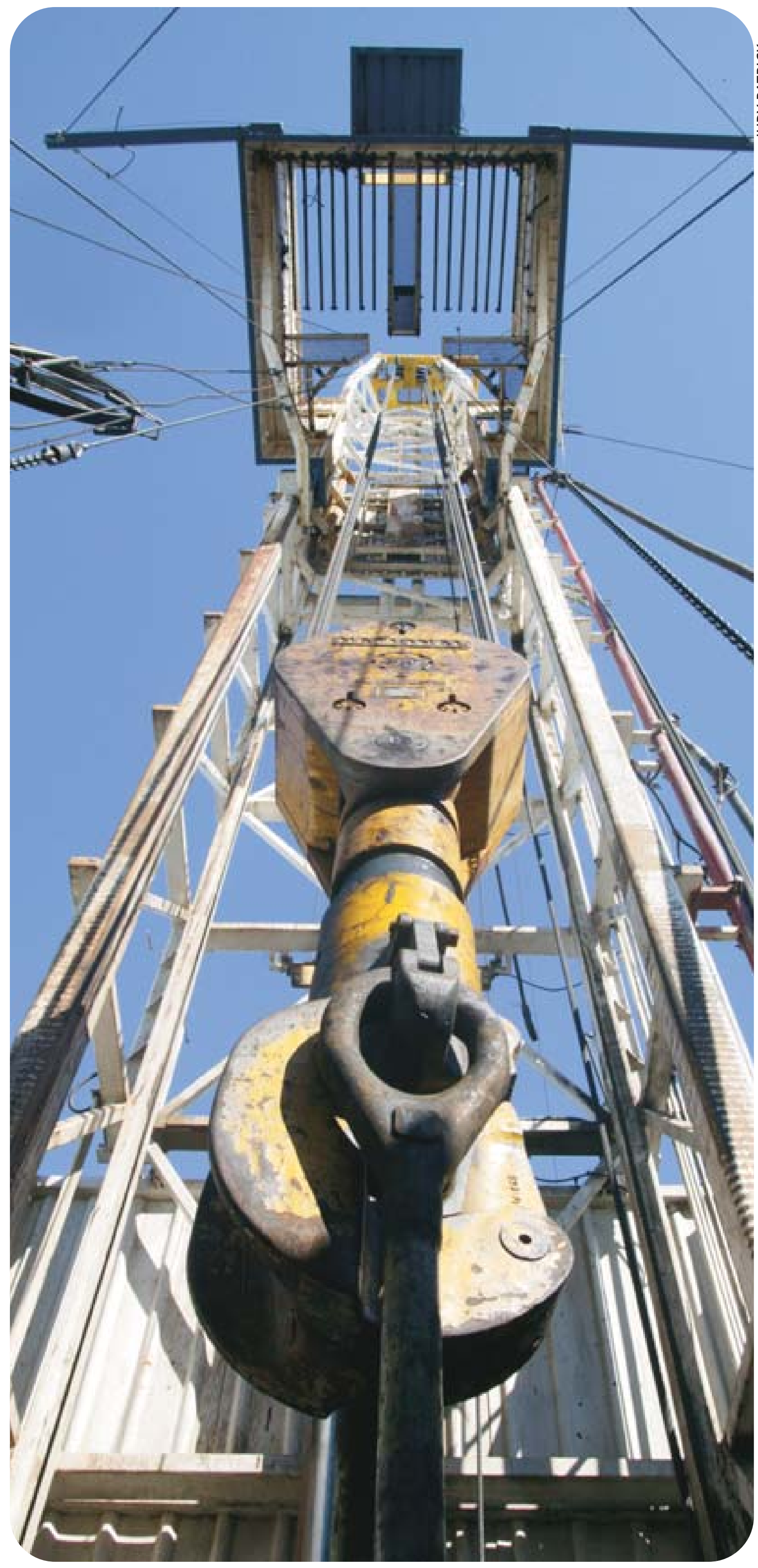
Mackenzie Rig Status

Canadian Beaufort Sea

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
SDC Drilling Inc.			
SSDC CANMAR Island Rig #2	SDC	Set down at Roland Bay	Available

Central Mackenzie Valley

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Akita/SAHTU			
Oilwell 500	51	Still out of the NWT, but is again available	Available
TSM 7000	34	On the move to East Mackay I-78 in the Sahtu	MGM Energy Corp.


JUDY PATRICK

Baker Hughes North America rotary rig counts*

	Jan. 25	Jan. 18	Year Ago
US	1,753	1, 749	2,008
Canada	621	601	682
Gulf	51	48	42

Highest/Lowest

US/Highest	4530	December 1981
US/Lowest	488	April 1999
Canada/Highest	558	January 2000
Canada/Lowest	29	April 1992

*Issued by Baker Hughes since 1944

The Alaska - Mackenzie Rig Report is sponsored by:

ARMSTRONG

● GOVERNMENT

Throughput committee focused on oil

Governor's oil tax bill has 1st hearing in committee co-chaired by Peter Micciche, who's looking for more production from tax changes

By STEVE QUINN

For Petroleum News

Sen. Peter Micciche has been in office just a few weeks and he's quickly immersed himself in the heavy-hitting items facing the Legislature the next two years: oil and gas tax reform, and advancing a natural gas pipeline project. Micciche, a Soldotna Republican, sits on the Senate Resources Committee and the Special Committee on In-State Energy. He also co-chairs the Special Committee on TAPS Throughput. This committee quickly began holding hearings on Gov. Sean Parnell's oil tax reform bill, SB 21.

He's not new to public service. Before coming to Juneau, he served as Soldotna's mayor for five years; he also held a city council seat before that. Micciche also found himself on the hot seat from reporters for prospective conflict of interests. Micciche works for ConocoPhillips, which stands to benefit from any tax reduction he backs.

SEN. PETER MICCICHE

Micciche, also a commercial fisherman with a drift gillnet permit, never ducked the questions and confidently defended his committee assignments and positions on statewide resource development in an interview with Petroleum News.

You've already received pushback on possible conflict of interest. How do you respond to the criticism?

Micciche: if you go back to the forefathers of the United States, the folks who wrote the Constitution, the folks who served in early Congress, they were all in agriculture and in similar industries and they regulated agriculture and similar industries. Now, if you walk forward to almost 60 years ago in Alaska, the primary industries in those days had excellent representation in the Legislature. They were fishermen, they were miners, they were loggers who represented our primary industries. Oil and gas is just another primary industry in Alaska. Looking today there are people in the Legislature that are in many industries the Legislature deals with: attorneys who deal with labor issues, union issues in their day job, if you will; we've got educators someone could view as the fox in the henhouse for PERS and TERS issues; and we've got oil and gas people. I frankly would like to see legislators who have it going on; they've got a background in these industries and they understand some of the details of issues facing the Legislature. I listed those examples, not because they are in conflict of serving, but for all of us conflicts will arise. What's imperative is that we are transparent about conflicts when they occur and we get a review by ethics and we make sure the public is aware of any potential conflicts and we move forward. Every member of this body will likely be declaring.

Petroleum News: So you knew what you were going to face this sooner rather than later?

Micciche: I did. I'm proud to be here. I'm proud of the industry. I'm proud of the industry's place in Alaska's community. Clearly, as we've seen in the last few weeks, it's beneficial for the people of Alaska to have someone that intimately understands these issues for the people of Alaska. I'm here as an Alaskan elected by my constituents who were aware of where I partially earn my living. I say partially because I'm also a commercial fisherman in Cook Inlet. Although there were one or two bad apples in the past that in my view when you compromise the public's trust should spend a long time in a small room with no windows, we can't include the other people who serve honorably. If there is a problem, I want the public to contact me or our office anywhere along the way in my career, which I expect will be a long one, to talk about any issues where they believe there is a potential conflict. I'm not here as an oil and gas employee; I'm here as a concerned Alaskan. One of the primary reasons I'm here is I see us moving away from providing opportunities we had as young people and I think I have the tools to help.

Petroleum News: What is the purpose of that committee (Senate Special Committee on TAPS Throughput) and what are your priorities?

Micciche: The purpose of that committee is to reverse decline. We can talk about oil taxes, but it's not an oil tax committee. We are the first to be given SB 21, the governor's oil and gas tax proposal, however our primary focus is to look at the operational permitting, leasing and conditional issues for discovered oil to become produced oil — to decrease the decline in throughput of TAPS. We recognize that if there is an oil tax change, folks are concerned about lost revenue. I'm one of those people. However the biggest threat to Alaska's revenue stream — that 92 percent revenue stream — is the decline of production that produces that revenue of for the state. Our goal is to flatten that decline. Our ultimate goal is to increase production to Trans Alaska Pipeline System.

Petroleum News: How can the committee pave the way for that?

Micciche: We specifically are going to be looking at things like water and gas handling limits or bottlenecks to production; access to existing production and future exploration production locations; efficient permitting; we're as concerned as anyone with protecting the environment, but we want to eliminate any waste and redundancy in the permitting process; the Alaska lease program; tariff issues; leveling the Arctic environment and conditional challenges; limited available equipment, workforce and support industries; limited and aging infrastructure; state and federal regulatory hurdles; environmental litigation, specifically looking to narrow lead time; understanding global competition for industry investment capital; understanding the effects of past incentives and the potential for increasing Alaska hire; the effects of decoupling viscous oil and natural gas from traditional North Slope oil production; incentivizing specifically for new oil in middle earth exploration development, so south of 68 and north of Cook

see MICCICHE Q&A page 14

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Petroleum News and its supplement, Petroleum Directory, are owned by Petroleum Newspapers of Alaska LLC. The newspaper is published weekly. Several of the individuals listed above work for independent companies that contract services to Petroleum Newspapers of Alaska LLC or are freelance writers.

OWNER: Petroleum Newspapers of Alaska LLC (PNA)
Petroleum News (ISSN 1544-3612) • Vol. 18, No. 5 • Week of February 3, 2013
Published weekly. Address: 5441 Old Seward, #3, Anchorage, AK 99518
(Please mail ALL correspondence to:
P.O. Box 231647 Anchorage, AK 99523-1647)
Subscription prices in U.S. — $98.00 1 year, $176.00 2 years, $249.00 3 years
Canada — $185.95 1 year, $334.95 2 years, $473.95 3 years
Overseas (sent air mail) — $220.00 1 year, $396.00 2 years, $561.00 3 years
"Periodicals postage paid at Anchorage, AK 99502-9986."
POSTMASTER: Send address changes to Petroleum News, P.O. Box 231647 Anchorage, AK 99523-1647.

● FINANCE & ECONOMY

‘Bitumen bubble’ to cost Alberta C$6B

Province’s premier hammers home message ‘we absolutely must’ find ways to get Alberta oil to multiple customers around the world

By GARY PARK
For Petroleum News

Alberta Premier Alison Redford started what she called a conversation with Albertans by doing all the talking in an eight-minute TV address about the dismal state of her province’s petroleum-fueled finances.

The response over the past week has been a lot of head scratching as Albertans try to figure out how Redford will deal with a projected fall of C$6 billion in oil and gas royalties over the coming year without raising taxes while meeting her pledge “not to take an axe to government spending across the board.”


ALISON REDFORD

Just in case anyone had trouble grasping C$6 billion, Redford explained that it was equivalent to her government’s entire education spending for a year and noted that 30 percent of the province’s budget is funded by oil and natural gas revenues.

The root of the problem is simply stated: Oil prices, especially those for Alberta’s bitumen, are sinking and creating what Redford calls a “bitumen bubble”; natural gas prices have been in the doldrums for more than two years; and whatever chance Alberta producers have to open up new markets is entangled in a national debate over whether new pipelines should be built to the east, south and west.

“We have a duty to ensure that our resources ... get to new markets at a much fairer price,” she said. “We absolutely must find ways to get Alberta oil to multiple customers around the world and get a competitive price.”

Chasing Brent

That means chasing customers in Asia who pay benchmark Brent prices rather than relying on U.S. markets where the price gap between bitumen and West Texas Intermediate has been hovering around US$30-$40 per barrel in recent weeks.

For the 2012-13 budget year which ends March 31, the Redford government had forecast a WTI price of US$99.25 per barrel and a Western Canadian Select price at the province’s Hardisty Hub of C$83.28 per barrel.

The challenge facing Alberta is mirrored in its Sustainability Fund, comprising surplus oil and gas revenues that are drawn down in difficult times. Over the past three years alone that fund has slumped to C$5 billion from C$14.9 billion.

“It isn’t the (WTI) price that is causing the real problem,” she said. “Historically, the price we receive for our oil has been a few dollars lower than (WTI) and that difference has been manageable.

“But since September, that gap has grown considerably and the trend is getting worse for the foreseeable future.

“The vast majority of our oil is now bitumen from the oil sands. And because of the rapidly growing levels of oil production in the United States and the fact we have virtually nowhere else to sell our oil but the U.S. market, Alberta is getting just over US$50 a barrel for our oil.”

No option

Redford said Alberta has no option but to put its finances on a more stable footing. A province as prosperous as Alberta should not be as susceptible as it is to swings in the price of oil and gas.

“It’s why I will continue to fight for a Canadian energy strategy that gets our oil both to the west and east costs in Canada and to refineries in the U.S. Gulf Coast and to markets overseas, particularly growing economies in Asia.

“That means we absolutely must find ways to get Alberta oil to multiple customers around the world and get a competitive price,” she said, while conceding that won’t happen overnight.

“It will take focus and determination over the next several years to open new markets,” Redford said.

The problem for Alberta is that it can’t act alone to gain access to Redford’s cherished goal of Asia, not when the British Columbia government of Premier Christy Clark is so reluctant to clear the way for Enbridge and Trans Mountain pipelines that could carry a combined 1.42 million barrels per day to tanker terminals on the Pacific coast and final approval is needed from the Obama administration to ship another 830,000 bpd to the Gulf Coast.

> *“And because of the rapidly growing levels of oil production in the United States and the fact we have virtually nowhere else to sell our oil but the U.S. market, Alberta is getting just over US$50 a barrel for our oil.”*
> **—Alberta Premier Alison Redford**

Glimmer of hope

However, there is a growing glimmer of hope on Canada’s East Coast where New Brunswick Premier David Alward is rolling out a welcome mat for a pipeline that could carry 500,000 to 1 million bpd to the Irving Oil refinery and a deepwater port at Saint John.

Alward plans his first trip to Alberta in early February to meet with Redford, visit the oil sands region and speak with industry leaders, making it clear he would welcome a pipeline that would provide cheap feedstock for the Irving refinery, which currently relies entirely on imported crude for its feedstock.

Redford and Alward have also been wooing Quebec Premier Pauline Marois, who faces determined opposition to pipelines from Alberta, despite the dependence of Quebec refineries on imported crude.

Redford views a cross-Canada pipeline as “critically important,” claiming it is “quite feasible” and “economically viable.”

TransCanada Chief Executive Officer Russ Girling told a CIBC World Markets conference Jan. 24 his company will decide “within the next few months” whether it will hold an open season to test shipper interest in crude oil pipelines to the North American East Coast to compete for business with 1 million-2 million bpd of imported crude.

He said the future of those plans hangs on “probably five big players,” who are likely to sign up if they see a chance to reduce the current price differential between light and heavy crudes. ●

Contact Gary Park through publisher@petroleumnews.com

EXPLORATION & PRODUCTION

Kulluk remains stable in Kiliuda Bay

Naval architects have confirmed that damage sustained by the Kulluk, Shell's floating drilling platform, following the grounding of the vessel on Dec. 31, "poses no threat to the stability or integrity of the Kulluk while anchored in Kiliuda Bay," the unified command for the Kulluk grounding incident announced in a Jan. 30 news release.

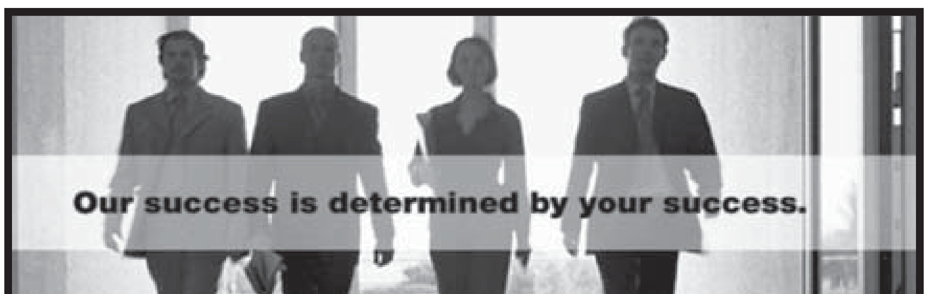
The Kulluk was towed to a safe anchorage in Kiliuda Bay on Jan. 7 after being refloated.

The unified command has yet to decide on when and how to relocate the Kulluk for permanent repairs and is waiting for further analysis of data gathered from inspections of the vessel and for relocation recommendations from the U.S. Coast Guard and Det Norske Veritas, the engineering firm commissioned to assess the condition of the vessel.

Meantime, the response team has made some preparations for the eventual towing of the Kulluk from its present anchorage. The team has obtained some necessary tow equipment and has secured openings such as windows and hatches on the vessel's main deck — some of this work has involved the installation of temporary steel structures to make the vessel water- and weather-tight, the unified command said.

The Native village corporation for Old Harbor, the village close to the grounding site, is collaborating with the unified command to develop plans to clean up lifeboat debris that ended up on the shore after the grounding.

—ALAN BAILEY



● F I N A N C E & E C O N O M Y

Talisman takes knife to costs

By GARY PARK

For Petroleum News

Talisman Energy has sent jitters through the Canadian oil patch by putting out word it will cut at least 20 percent of its general and administrative costs by eliminating jobs and divesting non-core assets.

"What we're doing is rationalizing the size of the G&A through looking at how we optimize efficiencies, both in the corporate center and in the regions," Executive Vice President Helen Wesley told an institutional investor conference in Whistler, British Columbia.

The downsizing, which targets C$1.3 billion of annual G&A costs, was initiated four months ago when Hal Kvisle, former chief executive officer at TransCanada, replaced John Manzoni in the top job and set to work overhauling the far-flung operations of the Calgary-based independent.

Richard Herbert, executive vice president of exploration, said that could include the sale of assets in Poland and Peru and reducing the company's footprint in North America, while concentrating on three core regions — Southeast Asia, which generates Talisman's only free cash flow today, the North Sea and North America's unconventional resources.

Herbert said Talisman has weighed a full range of options from asset sales to joint ventures and splitting up the company, conceding that "we wouldn't have been able to set up a North American business independently with the current debt that we've got."

Wesley said the objective is to reduce the company's widely spread focus and concentrate on being more "streamlined in terms of the portfolio."

Cautious on asset sales

Herbert said Talisman is moving cautiously on asset sales, predicting "some action in 2013," but emphasizing that considerations include "some very important relationships we have as a company with state oil companies like Petronas in Malaysia, or Pertomina in Indonesia, or Ecopetrol in Colombia."

Herbert said Talisman has weighed a full range of options from asset sales to joint ventures and splitting up the company, conceding that "we wouldn't have been able to set up a North American business independently with the current debt that we've got."

But he said that selling Talisman is "not something that we're putting any focus on right now," although there are no plans to increase oil and natural gas production this year.

Herbert said Talisman has now completed three wells and is drilling two more in Iraq's Kurdistan region and estimates finding and development costs are "probably among the lowest left in the world."

He said the company has found an oil column that is almost 150 meters thick and is now faced with a decision on whether to "bring in partners or monetize it entirely (after) growing value by appraising what is clearly a very exciting play." ●

Contact Gary Park through publisher@petroleumnews.com

Taqa North also shrinking

Taqa North, the Calgary-based company owned by state-owned Abu Dhabi National Energy Co., has added its name to the list of companies that are shrinking their payrolls.

It confirmed Jan. 28 that 50 of its 950 employees will be laid off as part of a reorganization to streamline operations by reducing costs and increasing efficiency.

It confirmed Jan. 28 that 50 of its 950 employees will be laid off as part of a reorganization to streamline operations by reducing costs and increasing efficiency.

"In a tight natural gas market you really need to be top quartile, top decile in your ability to operate and your ability to execute your capital and drilling plans and we weren't there," said Taqa President Ed LaFehr.

He said that since Taqa entered Canada four years ago by acquiring three companies for C$7.5 billion it has run the assets through three geographical divisions.

It now plans to change to a "functional" single stream model, he said.

Taqa averaged North American oil and natural gas production of 84,500 barrels of oil equivalent per day in the first three quarters of 2012, exiting the year at 91,000 boe per day after acquiring NuVista Energy to add 5,000 boe per day.

LaFehr said 80 percent of the 2013 capital budget is earmarked for oil and liquids-rich gas plays as Taqa targets an increase in its 30 percent liquids production weighting.

—GARY PARK

● ALTERNATIVE ENERGY

Court faults EPA on biofuel projection

American Petroleum Institute hails ruling on mandate for refiners to use a renewable fuel that so far is commercially 'nonexistent'

By WESLEY LOY
For Petroleum News

A federal court recently dealt a setback to the government's advancement of biofuels as a substitute for oil.

The Jan. 25 decision from the U.S. Court of Appeals for the District of Columbia had to do with the Environmental Protection Agency's forecast of cellulosic biofuel production for 2012.

Under federal law, EPA implements regulations to ensure that transportation fuel sold in the United States has a minimum volume of renewables such as cellulosic biofuel blended in.

Cellulosic biofuel is an "advanced biofuel," less polluting than other kinds of renewables, derived from sources such as switchgrass and agricultural wastes.

"When Congress introduced the cellulosic biofuel requirement in 2007, there was no commercial-scale production at all," the court ruling said.

But on the expectation of significant development in the biofuel industry, Congress mandated the use of millions of gallons of cellulosic biofuel each year. EPA forecasts annual cellulosic biofuel production, forming the basis for how much refiners are required to buy to comply with the federal renewable fuel standard.

The trouble is, cellulosic biofuel hasn't yet become commercially available, argued the American Petroleum Institute, which went to the court to challenge EPA's 2012 projection.

In its 14-page opinion, the court said "we agree with API that because EPA's methodology for making its cellulosic biofuel projection did not take neutral aim at accuracy, it was an unreasonable exercise of agency discretion."

'Absurd mandate'

API is a national trade association for oil and gas producers, refiners and marketers.

"We are glad the court has put a stop to EPA's pattern of setting impossible mandates for a biofuel that does not even exist," API's Bob Greco said in a Jan. 25 press release. "This absurd mandate acts as a stealth tax on gasoline with no environmental benefit that could have ultimately burdened consumers."

Refiners and importers of gasoline and diesel would have had to pay over $8 million for credits to cover the 2012 mandate of 8.65 million gallons of the nonexistent biofuel, API said.

"This decision relieves refiners of complying with the unachievable 2012 mandate and forces EPA to adopt a more realistic approach for setting future cellulosic biofuel mandates," Greco said. "The court has provided yet another confirmation that EPA's renewable fuels program is unworkable and must be scrapped."

The court noted that while EPA based its 2012 cellulosic biofuel production forecast on information from the Energy Information Administration and elsewhere, EPA also was interested in promoting the growth of the biofuel industry. And EPA indicated a concern that setting too low a production outlook could depress the market for cellulosic biofuel.

It was as though EPA was saying, "Do a good job, cellulosic fuel producers. If you fail, we'll fine your customers," the court opinion said.

This effectively put refiners in a tough spot, as they have no control over how much cellulosic biofuel is produced.

It was as though EPA was saying, "Do a good job, cellulosic fuel producers. If you fail, we'll fine your customers," the court opinion said.

Biofuel producers react

The ruling wasn't entirely favorable for API. The court rejected API's challenge of EPA's refusal to lower required volumes of other advanced biofuels. In its 2012 regulation, EPA concluded other sources of advanced biofuels, such as imported sugarcane ethanol and biomass-based diesel, could make up for the shortfall in projected cellulosic biofuel.

The Renewable Fuels Association, in a Jan. 25 press release, said the court "vacated the cellulosic biofuel standard because it believed that EPA had impermissibly set the volume with the objective of promoting growth in the industry, rather than simply making an accurate prediction. The biofuels organizations strongly disagree with the court's characterization of what EPA did — EPA did not determine a reasonably achievable volume and then inflate it. Rather, it set the volume based on the best information available to it at the time."

In affirming EPA in part, the court decision "once again rejects broad-brushed attempts to effectively roll back" the federal renewable fuel standard, the association said. ●

Contact Wesley Loy at wloy@petroleumnews.com

FINANCE & ECONOMY

Buccaneer gets $100M credit facility

Buccaneer Energy Ltd. has executed a credit facility with the Chicago-based Victory Park Capital worth as much as $100 million, the company announced on Jan. 29.

Through the two-part credit facility, Buccaneer can use its ownership of the Kenai Loop gas field and its tax credits under Alaska's Clear and Equitable Share to borrow funds.

The first part of the deal allows Buccaneer to borrow up to $75 million through a metric based on the value of the proved developed producing reserves of the Kenai Loop field, with the possibility to add capacity based on the proved undeveloped reserves. Through the nature of the arrangement, Buccaneer could theoretically borrow larger amounts in the future, should its work at Kenai Loop increase the proved reserves of the field.

The second part of the deal allows Buccaneer to pre-fund drilling and development work eligible for ACES credits, up to $25 million. Between the two parts of the agreement, Buccaneer expects to be able to fund its drilling at Kenai Loop and West Eagle for 2013.

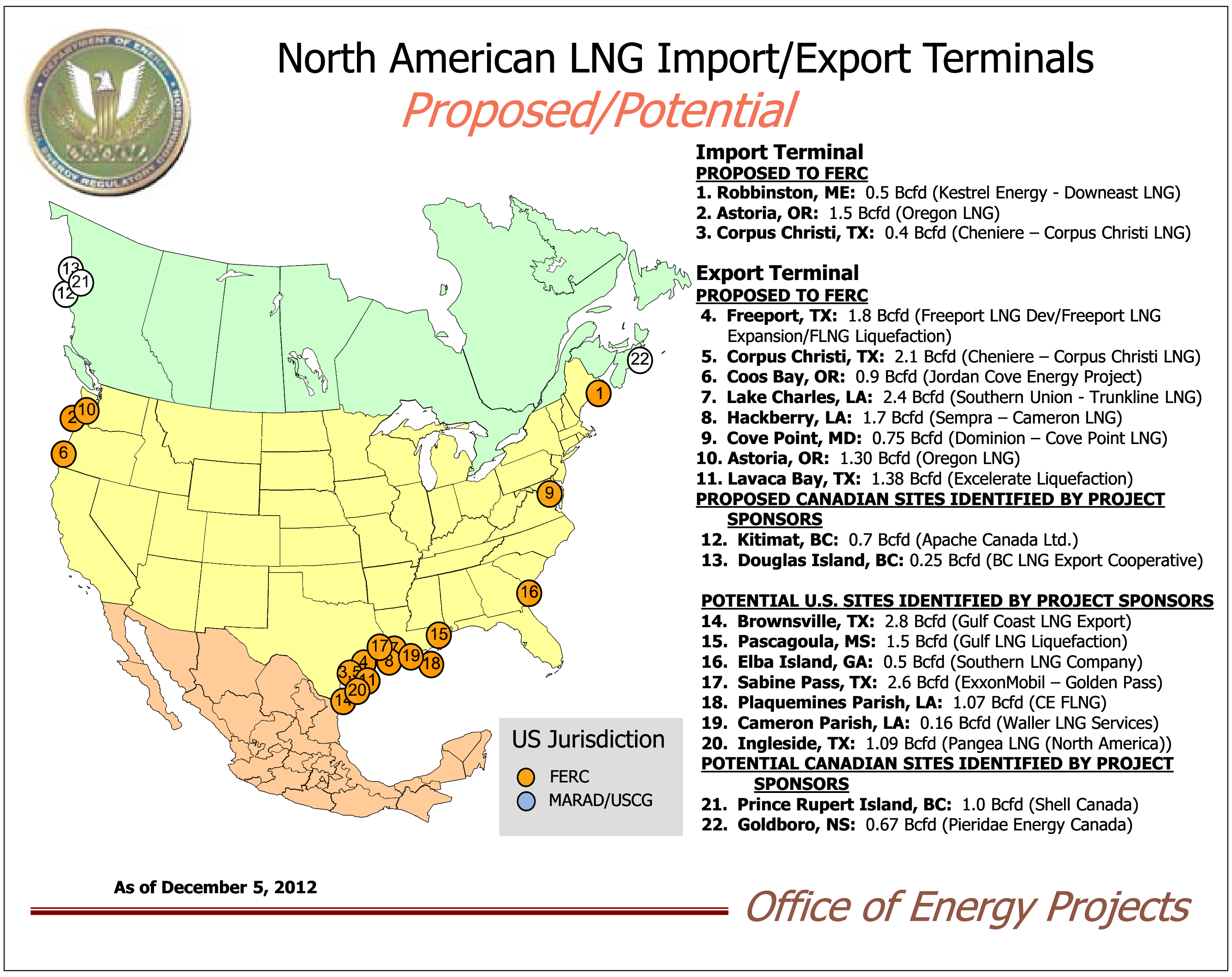
Buccaneer said it has already drawn on the Victory Park credit facility "to refinance its previous lender and to pay fees and expenses associated with this transaction."

—ERIC LIDJI

● NATURAL GAS

NA LNG looks to exporting to survive

In a change from a decade ago, the North American liquefied natural gas industry is now gearing up to export billions of cubic feet



By BILL WHITE

Researcher/writer for the Office of the Federal Coordinator

North America's liquefied natural gas industry is gearing up to shift into reverse.

Normally a business in reverse connotes retreat and possibly doom. But LNG ports hope just the opposite will be true, that they will find their future and salvation.

A decade ago the industry was certain North America would be importing billions of cubic feet of gas a day to slake consumers' growing thirst for the fuel in an era of declining domestic production.


BILL WHITE

Executives of major oil and gas companies hopped on board. Bankers got in line. Politicians pressed regulators to speed up approvals. Even the chairman of the Federal Reserve Board rattled cages about the need for LNG.

And from all that commotion, LNG-import proposals sprang up and multiplied. (Also during this time, 30-year-old plans were revived for an Alaska North Slope pipeline to flow gas to a continent believed to be on the brink of a new energy crisis.)

Before 2000, North American had just two operating LNG-import terminals. But in the next 11 years, two mothballed import terminals restarted and expanded, and eight new terminals were built in the United States, plus one in Canada and two in Mexico.

Collectively, the terminals can feed about 20 billion cubic feet a day of natural gas into the North American pipeline grid, enough to satisfy one-third of U.S. consumption on an average day.

But mostly those terminals are idle, as obsolete as a Rust Belt factory. At least five of them didn't import a droplet of LNG in 2012 through November.

All the executives, bankers and politicians were wrong. U.S. gas production didn't decline, it grew astoundingly thanks to new techniques to blast oil and gas from stingy strata of shale deep underground.

1 2 SERIES

Now the North American LNG industry's new vision involves exporting that overabundance of gas. It's a radical redirection. It's like Sir Edmund Hillary, part way up Mount Everest, deciding to become a deep-sea diver instead.

The LNG industry's about-face is part of a larger upheaval that the shale oil and gas boom has sparked. Many power plants that once burned coal now favor natural gas. Former oil pipelines plan to carry gas. And, as supply and demand adjust to the new world of shale-gas production, pipelines that once flowed methane south or east now aim to push it north or west.

For the LNG industry, the question has become: Can it pull off its audacious reversal?

Export mania

In the United States, one export terminal already is under construction. Cheniere Energy is adding liquefaction production to its mostly idle import terminal at Sabine Pass, La.

Cheniere hopes to produce its first batch of LNG in 2015.

As of mid-January 2013, 16 other U.S. proposals exist at least on paper, based on filings with the U.S. Department of Energy. Department approval is required before gas can go to Japan, China, India, Europe or any of the other countries targeted by the applications.

Three of the 16 have applied to the Federal Energy Regulatory Commission for permission to build liquefaction facilities. Five more are doing preliminary work with FERC in advance of applying for authority to build and operate export plants.

In Canada, at least six projects are under active consideration. Five are proposed for the nation's West Coast and one for the East Coast.

All together, the U.S. and Canada projects propose to export up to 30 billion cubic feet a day. That's a breathtaking quantity — equal to roughly a third of all gas production from the two countries in 2012.

No one thinks that much gas will exit North America. Some proposals will remain nothing more than ideas. Some will get approved but never built for lack of financing or customers.

But the global gas industry abounds in frenzied fascination over the possibility of North American LNG exports. Such exports, especially if sizable, could shake up how gas is bought, sold and priced across the world.

Global LNG consumption averaged about 30 billion to 35 billion cubic feet a

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LNG EXPORT

day in 2012. That quantity is predicted to grow strongly in coming years as gas demand from China, India and other developing economies blossoms.

Most speculation on how much North America LNG actually gets shipped generally ranges from 5 billion to 10 billion cubic feet a day — or the output from four to six projects.

Two U.S. energy consultancies in October 2012 jointly predicted foreign buyers would want about 10 bcf a day. LCI Energy Insight and Energy Ventures Analysis Inc. were more specific: The winners would be two Lower 48 projects, one in Alaska and three on Canada's West Coast.

As for the predicted winners: "It was deemed that the combination of their transportation advantage (nearness to market), (oil and natural gas) liquids revenues and partnership with either foreign partners or the majors, would provide them with a competitive advantage ... in what appears to be an intensely competitive market," they said.

Separately in October, a Shell executive predicted about 8 bcf a day of exports.

More recently, Kenneth B. Medlock III, an energy economist at Rice University in Houston, said: "I doubt we'll see more than 6 billion."

Brownfield vs. greenfield

To better understand the proposed export projects and their prospects of success, in can be helpful to grasp some industry jargon.

The projects are either "brownfield" or "greenfield."

Brownfield is an industry term for projects where some, if not much, of the infrastructure already is in place. Export projects proposed for sites where import terminals stand are brownfield.

By contrast, greenfield projects start from scratch, developing a new site.

If you're trying to play in the LNG export game, you've got a big advantage if you propose a brownfield project.

Brownfield proposals already have expensive tanker berths, high-tech LNG storage tanks, pipeline connections, roads and utilities installed. The major extra infrastructure they need is muscular machinery that superchills methane to minus 260 until the vapor becomes liquid. Liquid gas takes up less space than a vapor, making it easier to ship in bulk across oceans.

Lower 48 brownfield projects might cost half as much to build as greenfield — perhaps $5 billion to $10 billion for big brownfield projects, compared with possibly $20 billion and up for big greenfield LNG terminals.

Another real advantage in a world where time is money: Typically brownfield can be permitted more quickly than greenfield.

Of the pending U.S. export proposals, seven would be brownfield projects. Almost every U.S. import terminal is maneuvering to add export services.

Another nine big U.S. proposals — and all of the Canadian projects — involve greenfield development. (The Canadian West Coast projects, however, lie much closer to Asia's major LNG markets — Japan, South Korea, China and Taiwan — than the U.S. brownfield projects, all of which lie along the Gulf of Mexico or East Coast. Their advantage lies in that proximity and the resulting lower cost of transporting LNG to Asia.)

Cheniere's Sabine Pass export project under construction illustrates how a brownfield project can get approvals quickly.

Cheniere obtained FERC permission to build its import terminal in 2004. Years of construction ensued and the terminal took its first LNG cargo in 2008.

But by 2008 it was becoming clear the terminal wouldn't be very busy. Shale-gas production was catching on and North America needed far less imported LNG than predicted just a couple of years earlier.

Almost immediately, Cheniere applied for and received Energy Department permission to "re-export" LNG. A Sabine Pass customer would buy a cargo of foreign-made LNG, offload it to hold in cold storage, then pipe it back onto a tanker for delivery to a foreign buyer when the price was right.

But occasional re-export cargoes is a poor long-term business strategy for a multibillion-dollar investment.

In 2011, Cheniere took the next step in its evolution. The company asked for permission to liquefy U.S. natural gas for export. In less than nine months, the Energy Department authorized exports anywhere in the world, provided FERC sanctioned construction. FERC gave its OK in 2012, 15 months after getting Cheniere's application.

Before acting, FERC conducted an environmental assessment. Assessments are less comprehensive and take less time than full-blown environmental impact statements, which can run into the thousands of pages and cost an LNG-project developer hundreds of millions of dollars.

The assessment tallied 142 pages, plus attachments. FERC staff did an assessment instead of an environmental impact statement "because all the proposed facilities would be within the footprint of the existing LNG terminal, which was previously the subject of an EIS, and the relevant issues that needed to be considered were relatively small in number and well-defined," FERC said.

Other permitting agencies took a similar tack. Because the import terminal was rarely used, the air emissions, ship traffic and other issues for an export terminal would be no greater than allowed already.

In general, with some exceptions, FERC has environmental assessments planned or under way for the proposed brownfield export projects that have applied to the agency so far, and full EISs for the greenfield sites.

Will LNG buyers step up?

All of the export frenzy, the engineering and marketing under way, the possible tens of billions of construction dollars needed, they're all based on a simple premise:

LNG can be made cheaply in North America and sold at a profit in Asia and Europe.

That premise is rock solid in describing today's market and prices. But not everyone believes the premise has staying power.

The raw material of LNG — methane — is available at ultra-low prices right now in North America because so much shale gas is flooding the market. Last year, the market price at the Lower 48's Henry Hub averaged $2.75 per million Btu (roughly 1,000 cubic feet of methane). That was the lowest average since 1999. (The price has risen in the past several months, reaching $3.50 as of mid-January and climbing to $4 in the futures market for deliveries next winter.)

But overseas, LNG spot market prices are sky high. They average $15 to $18 in Asia at present, according to trade journal Heren Global LNG Markets. Spot gas prices in Europe range from $10 to $12. (Deliveries under long-term contracts can cost less than these prices.)

That gap between low North America prices and high prices elsewhere has created what finance professionals call an "arbitrage opportunity" — profiting when the same commodity fetches different prices in different markets. Profits amass by buying in one market and selling in another.

Even after adding possibly $5 to $7 in cost to liquefy North American gas and ship it long distances from the Lower 48, the arbitrage opportunity remains — at today's prices.

Unfortunately for those who would like to take this arbitrage profit now, they can't. The sole working U.S. LNG export plant — ConocoPhillips' 44-year-old plant at Nikiski, Alaska — is small and winding down operations as its federal export authority expires in March. The only other plant authorized for exports to anywhere in the world is Cheniere's Sabine Pass site, which is under construction and won't be ready to ship before 2015.

Cheniere and other LNG export entrepreneurs are gambling that the price gap will remain wide enough, and long enough, to make their industry's new direction viable. (In all cases, the proposed North American export terminals merely plan to liquefy somebody else's gas — called "tolling services" within the industry — while the gas sellers and/or buyers would bear risk of guessing wrong on commodity prices.)

But forecasting future natural gas prices is as maddening and impossible as accurately predicting earthquakes.

Since 2000, the average annual U.S. price has been $5.33 per million Btu. Within those years, however, the annual average has swung between an $8.86

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● GOVERNMENT

NMFS revising its proposed Arctic EIS

Agency plans to include an alternative allowing four drilling programs in the Beaufort and four programs in the Chukchi annually

By ALAN BAILEY
Petroleum News

The National Marine Fisheries Service, or NMFS, has announced that it is preparing a revised version of its draft environmental impact statement for Arctic offshore oil and gas exploration, taking into consideration comments the agency received on an earlier draft of the document. That earlier draft caused considerable concern in the oil industry because it would have limited exploration drilling, at best, to two programs per year in the Beaufort Sea and two programs in the Chukchi Sea, with those limitations applying across both the federal outer continental shelf and state waters around the coast.

During the public comment period on the draft environmental impact statement, or EIS, industry representatives pointed out that the number of drilling programs allowed per year would be substantially less than the number of companies operating offshore leases, a situation that would have prevented some companies from exploring in leases that they had purchased from state or federal authorities.

New alternative

NMFS now says that it is adding an alternative to the EIS, allowing up to four drilling programs in the Chukchi Sea and up to four programs in the Beaufort Sea. Other alternatives under consideration include a no-action alternative, in which the federal government would not in the future issue any seismic permits. This alternative would also stop the issuance of any authorizations for the disturbance of marine mammals during drilling operations, in effect prohibiting offshore drilling.

Other alternatives under consideration envisage allowing different amounts of offshore drilling and seismic activity, with one alternative requiring the use of some new seismic technologies and another requiring scheduled closures of some environmentally sensitive areas.

NMFS says that it will publish its new document for public review in the form of a draft supplemental EIS. The Bureau of Ocean Energy Management, or BOEM, has been working with NMFS on the document, with the North Slope Borough and the Alaska Eskimo Whaling Commission also involved.

Long history

Some people have questioned why NMFS is preparing the EIS, given that there does not appear to be any specific proposed activity of a type that would normally trigger an EIS development. The history of the EIS goes back to 2006 when the U.S. Minerals Management Service, BOEM's predecessor agency, elected to conduct a programmatic environmental assessment for envisaged multiple seismic surveys on the outer continental shelf. Over time, with concerns about the possible cumulative impacts of multiple offshore exploration programs, that original assessment morphed into an EIS that encompassed exploration drilling as well as seismic surveys, with NMFS becoming the lead agency in the EIS development. NMFS is an agency within the National Oceanic and Atmospheric Administration, or NOAA.

Delegation comments

Alaska's congressional delegation has lauded NMFS' willingness to listen to people's concerns about the draft document. And Sen. Mark Begich attributed the NMFS rethink in part to the actions of the federal Interagency Working Group, established by the Obama administration to coordinate federal Arctic permitting.

"The fact that NOAA heard what the delegation and I had to say and expanded the document speaks volumes for the process and framework established by the Interagency Working Group," Begich said. "I commend NOAA for taking another look at this."

Sen. Lisa Murkowski continues to express concerns about the need for the EIS.

"When we met with (NOAA) Administrator Lubchenco in April, I was clear that the original environmental impact statement was deeply flawed and went beyond the agency's expertise and mission," Murkowski said. "I appreciate the willingness to take a second look, but I continue to believe that this document is unnecessary and that NOAA is interfering with matters that rightfully belong under the jurisdiction of Interior." ●

continued from page 9

LNG EXPORT

high in 2008 to a $2.75 low in 2012. The daily average soared and plunged like a runaway rollercoaster, from a high of $18.48 to a low of $1.69 during that span.

Asian and European price swings have been nearly as wild. For a time in mid-decade, North American prices even exceeded gas prices overseas.

No one forecasted all that price volatility, although thousands of consultants, market watchers, investors and industry professionals tried.

The arbitrage opportunity began opening up around 2009 or 2010.

Asian buyers and others are starting to move on it. Companies from Japan, South Korea, China, India and Malaysia have recently invested in North American gas fields or LNG export plays. It's partly a matter of protecting themselves against high LNG prices. ●

Editor's note: This is a reprint from the Office of the Federal Coordinator, Alaska Natural Gas Transportation Projects, online at www.arcticgas.gov/north-american-lng-industry-looks-survival-through-exports.

Note: Part 2 of this story will appear in the Feb. 10 issue of Petroleum News.


ALASKA DEPARTMENT OF FISH AND GAME

Cleanup operations at the Ivan River reserve pit

● ENVIRONMENT & SAFETY

Chevron earns kudos for pit cleanup

Project involved excavating huge volume of drilling wastes at Ivan River gas field; Alaska officials call it a job well done

By WESLEY LOY
For Petroleum News

The Alaska Department of Fish and Game is commending Chevron for a cleanup operation at the Ivan River gas field.

The project involved excavating a reserve pit adjacent to the Ivan River pad within the Susitna Flats State Game Refuge.

Reserve pits once were commonly used in Alaska's oil and gas fields to hold drilling wastes such as rock cuttings and drilling muds. Such pits are no longer in favor as the industry has moved to other methods for handling wastes, such as grinding them for injection underground.

To fulfill a corrective action plan for closure of the Ivan River pit, Chevron proposed removing a huge volume of drilling wastes and then backfilling the pit with gravel.

The project, years in the planning, required a "substantial commitment on Chevron's part," said a Jan. 10 letter of commendation Randy Bates, director of Fish and Game's Habitat Division, sent to Chevron's George Cowie.

The project, years in the planning, required a "substantial commitment on Chevron's part," said a Jan. 10 letter of commendation Randy Bates, director of Fish and Game's Habitat Division, sent to Chevron's George Cowie.

"Extensive research was completed over the last several years and the project was well thought out and implemented," the letter said. "Approximately 10,500 cubic yards of material were excavated from the pit and transported to a facility in Oregon via barge for proper disposal. A similar amount of gravel fill was transported in from an off-refuge location and replaced within the pit. This work took place over approximately four months during the summer and fall of 2012 with little impact to refuge resources or users."

see CLEANUP KUDOS page 12

FINANCE & ECONOMY

Weiss is named to head BP Alaska

Janet Weiss has been named regional president of BP Alaska, succeeding John Minge who has been named chairman and president of BP America Inc.

The appointments are effective Feb. 15, BP said in a Jan. 29 statement.

Minge has headed BP's Alaska business since Jan. 1, 2009. In his new position he will be based in Houston and will be BP's lead representative in the U.S.

Weiss is currently regional vice president, resources, in Alaska, responsible for resource progression and subsurface activities, BP said.

JANET WEISS

Weiss holds a Bachelor of Science degree in chemical engineering from Oklahoma State University and has held engineering and executive posts in Alaska and the Lower 48.

Weiss began her career in Alaska in 1986, and has worked in Alaska as a process engineer, reservoir engineer, petroleum engineer and reservoir engineering advisor.

Her executive appointments include vice president of special projects for BP Exploration & Production and vice president for unconventional gas technology. She has also led BP's western Wyoming businesses and base operations for the company's Gulf of Mexico shelf.

JOHN MINGE

Eighteen years in Alaska

"BP's history in Alaska stretches back more than five decades and it is one of the largest and most important businesses in BP's global portfolio," Minge said. "Having spent 18 of her 27 years in the industry in Alaska, I am confident that Janet Weiss' background and experience are what BP Alaska needs to continue thriving as a major global energy producer."

Weiss will continue to be based in Anchorage, and in addition to responsibilities for BP's exploration, development and production activities in Alaska, she will be responsible for its interests in the trans-Alaska oil pipeline.

"BP Alaska is home to some of the most capable people in the industry and I am honored to be asked to lead them," Weiss said. "I've seen first-hand what they can achieve in even the most challenging of environments."

BP Alaska has more than 2,200 employees and more than 6,000 contractors and operates four fields on the North Slope, including Greater Prudhoe Bay, which together account for about two-thirds of the state's oil production.

BP has 23,000 employees in the U.S., the largest concentration of BP employees in the world, and its U.S. capital investments over the past five years exceed $52 billion, more, the company said, than it invests in any other country.

—KRISTEN NELSON

● NATURAL GAS

AIDEA weighing LNG trucking interest

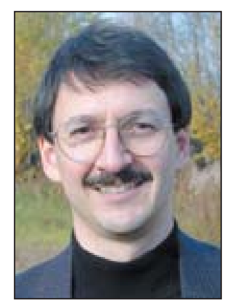
Therriault says public corporation received 16 letters of interest for a state-backed project to bring gas to the Interior

By ERIC LIDJI

For Petroleum News

While efforts to truck liquefied natural gas to the Interior have largely focused around four players to date, it appears many more are interested in bringing the project to life.

The Alaska Industrial Development and Export Authority received 16 responses to its request for letters of interest, the public corporation of the state recently announced.



GENE THERRIAULT

The list includes Golden Valley Electric Association, Pentex Alaska Natural Gas Co., Spectrum LNG LLC and the Interior Alaska Natural Gas Utility — four entities that have publicly expressed an interest in recent months in facilitating an LNG trucking project, either in part or in whole. It also includes many familiar names: the Alaska Gasline Port Authority, Alaska Power and Telephone, Arctic Slope Regional Corp., ASRC Energy Services, Black & Veatch, CB&I Services Inc., CH2MHILL, Guggenheim Partners, HDR Inc., KeyBanc Capital Markets, Northrim Bank and PND Engineers Inc.

AIDEA expects to have a preliminary analysis of the responses in February, but Gene Therriault — deputy director for statewide energy policy development for the Alaska Energy Authority and a former state senator — recently told the Senate Resources Committee the responses include both turnkey projects and proposals to collaborate.

The three goals of the Parnell administration, Therriault said, are: to provide the lowest cost gas to as much of the Interior as possible, to get gas to the Interior first while making the facility available to all Alaskans and to use the private sector as much as possible.

Aiming for $15 per Mcf

All the respondents, though, are seeking some part of the $355 million financial package that Gov. Sean Parnell proposed late last year to help bring natural gas to the Interior.

With those incentives, the state believes it can help develop a 9 billion cubic foot per year operation capable of delivering gas to consumers between $13.49 and $17.29 per thousand cubic foot, Therriault said. The state reached those figures using engineering information from Golden Valley Electric Association and Pentex Alaska Natural Gas Co., but Therriault told lawmakers that AIDEA and AEA have developed a model that can forecast the delivered price under various volumetric and financing configurations.

A benchmark price for the project, Therriault said, is $15 per mcf, or roughly half of what Interior consumers currently pay to heat their homes and businesses with fuel oil.

The proposed financial package includes a $50 million allocation, $150 million in direct AIDEA bonds and another $125 million in Sustainable Energy Transmission and Supply funds managed by AIDEA, and $30 million in preexisting tax credits for storage projects.

A benchmark price for the project, Therriault said, is $15 per mcf, or roughly half of what Interior consumers currently pay to heat their homes and businesses with fuel oil.

To help hit that target price, the state wants to divide the end users, Therriault said, by using the $50 million allocation to pay down only the utility customers' share of the project and thereby lower the price of an estimated 4.5 bcf per year piped to homes and businesses or used to generate electricity. The energy intensive industrial customers that are crucial for anchoring the project would pay a price with a higher debt component than the general public, but would still benefit from the size of the project, Therriault said.

The short presentation before the Senate Resources Committee on Jan. 25 was a prelude to a more involved consideration of the project scheduled to take place before the Senate Special Committee on In-State Energy on Jan. 31, after Petroleum News went to print.

Petroleum News will have a report on that hearing in the Feb. 10 issue. ●

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CLEANUP KUDOS

Revegetation planned

The Ivan River field is on the west side of Cook Inlet, northeast of the ConocoPhillips-operated Beluga River gas field.

A number of wells were drilled at Ivan River following its discovery in 1966. Production didn't start until 1990, however, after Unocal completed a pipeline to connect the field to the Enstar Natural Gas Co. line.

Chevron acquired the Ivan River field when it bought out Unocal in 2005. Hilcorp took over as Ivan River unit operator in January 2012 after it acquired Chevron's Cook Inlet assets.

Chevron's reserve pit cleanup involved filling "super sacks" with waste material, and then trucking the sacks off-site, according to the company's permit from the Habitat Division. The sacks were designed to contain the waste safely for transport.

Between 500,000 and 900,000 gallons of water also were to be removed from the pit.

Come spring, the area will be revegetated.

Groundwater monitoring will take place for at least three years at the site, the permit said. ●

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GOVERNMENT

Parnell reappoints Foerster to AOGCC

Among the appointments Gov. Sean Parnell delivered to the Legislature Jan. 30 was a reappointment of Cathy Foerster, currently the chair, to the Alaska Oil and Gas Conservation Commission.

Foerster, who holds the petroleum engineer seat on the commission, was first appointed 2005 and reappointed in 2007.

This reappointment is effective March 1; the term expires March 1, 2019.

—PETROLEUM NEWS

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PIPELINE ACTIVITY

from the Pump Station 1 incident.

The Jan. 8, 2011, discovery of spilled oil in the basement of a booster pump building at the station forced two shutdowns extending over several days.

On Feb. 1, 2011, the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration hit Alyeska with notice saying that as the result of an investigation, "it appears that multiple conditions exist on your pipeline facility that pose a pipeline integrity risk to public safety, property or the environment."

The notice focused on the pipeline's declining oil throughput, cooling crude temperatures and the potential for a pipeline freeze-up during a winter shutdown.

Keeping oil warm

PHMSA also raised concerns about inaccessible, below-ground station piping of the sort that leaked at Pump Station 1.

The ensuing consent agreement between the agency and Alyeska, reached in August 2011, laid out extensive work that Alyeska is busy trying to complete.

A recent Alyeska update to PHMSA, dated Jan. 14, described some of this work.

At Pump Station 1, major work is under way to replace below-ground piping. Alyeska also plans to replace below-ground piping at several other pump stations along the 800-mile line.

In November, Alyeska installed and tested a new mainline pump engine at Pump Station 12, the update said. The pump and engine are meant to enhance the pipeline's cold restart capability.

Alyeska also finished "enhanced recirculation" projects at Pump Station 4 and Pump Station 7 in December. The projects involved changing out values or making other adjustments to run oil through the pump stations more than once, which Alyeska has found to be an effective way to add heat to the crude.

PHMSA inspectors have been visiting some of the work sites.

To date, the agency has not levied any fines against Alyeska for the 2011 spill and pipeline shutdowns.

Pump Station 1 reconfiguration

Under the consent agreement, Alyeska is to replace or remove any piping along the pipeline system that can't be assessed with pigs and would, upon failure, compromise the safe operation of the pipeline.

Pigs are tools that move through a pipeline to check for problems such as corrosion.

Egan, the Alyeska spokeswoman, said the volume of work "is very significant and has been in the planning stages for several years."

The work to bring Pump Station 1 piping above ground is something that was in Alyeska's project plan even before the 2011 leak, she said.

"The benefit of elevating the piping at that station is to make it fully inspectable," Egan said.

She noted that the piping work coincides with the electrification and automation of Pump Station 1. It's the last station to undergo such a makeover in a long-running program Alyeska once referred to as "strategic reconfiguration."

The trans-Alaska pipeline has been moving North Slope crude oil since 1977. Alyeska runs the pipeline on behalf of the owners including BP, ConocoPhillips and ExxonMobil.

—WESLEY LOY

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GOVERNMENT

Rokeberg named to replace Giard as RCA commissioner

Gov. Sean Parnell has announced the appointment of Norman Rokeberg as a commissioner in the Regulatory Commission of Alaska effective March 1. Rokeberg replaces Kate Giard, who resigned as a commissioner on Jan. 4.

Rokeberg represented the Sand Lake area of Anchorage in the Alaska House of Representatives from 1995 to 2007. He is the owner and broker of The Rokeberg Co., an Anchorage real estate agency. He also co-owned Powerhouse Gym of Anchorage from 2001 to 2008. He earned a bachelor's degree in political science from Willamette University and is a member of numerous organizations such as the Anchorage Chamber of Commerce and Commonwealth North. As a member of the House, Rokeberg sponsored oil and gas legislation that created areawide leasing and modified royalties for marginal fields.

Rokeberg represented the Sand Lake area of Anchorage in the Alaska House of Representatives from 1995 to 2007.

In August Parnell appointed Rokeberg to the Alaska Royalty Oil and Gas Development Advisory Board, the board that advises the Department of Natural Resources on approval or disapproval of new royalty agreements with the state.

RCA says that departing commissioner Giard has taken a new job, working for Resource Data Inc., an Anchorage technology consulting firm. Giard had served nearly 10 years as a commissioner, having first been appointed on June 1, 2003. During Giard's tenure as commissioner, the RCA became embroiled in a number of high-profile, oil and gas related hearings, with Giard never shy of speaking her mind. These hearings included rate cases involving contentious Southcentral utility gas supply agreements with Cook Inlet gas producers; regulatory approvals for Cook Inlet Natural Gas Storage's Kenai Peninsula gas storage facility; approval of reversed gas flow in the Cook Inlet Gas Gathering System; and the hearing with the Federal Energy Regulatory Commission over whether the owners of the trans-Alaska oil pipeline should be allowed to recover the cost of their strategic reconfiguration project.

—ALAN BAILEY

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MICCICHE Q&A

Inlet; and investigating transition zone incentives for greater percentage of (Outer Continental Shelf) revenues.

Petroleum News: Was the committee your idea?

Micciche: The committee was the idea collectively of the Senate majority, realizing that simply reducing oil taxes was not going to magically increase throughput. It's going to help, but there are many factors that need to be considered.

Petroleum News: So the committee is not another layer of government, or duplicative?

Micciche: It isn't at all. Resources is going to have a significant load this year. The reason for these two committees — there is the TAPS throughput committee and the In-state Energy Committee — is to preprocess bills that are destined for Resources. They are temporary committees if you will. I imagine if they are successful in improving the outlook in Alaska's revenue stream, they may end up being something that stands. The idea right now is we feel we are at a critical intersection if you will of Alaska's revenue history. We want to give it an extra effort, bringing in the right people to make some productive policy decisions to flatten the decline of TAPS throughput. If you look at the makeup of all three committees there are common members. My primary expertise is natural gas processing and liquefied natural gas. I see natural gas and LNG as becoming our No. 2 industry the moment we open the valve on a natural gas pipeline. Alaskans are struggling, so our primary focus is natural gas energy for Alaskans through the spine of densely populated areas of the state, potentially some secondary products would offset the cost of energy in rural areas, hopefully a project that's designed for excess natural gas for export.

Petroleum News: What are your thoughts on the governor's oil tax bill and what have you learned?

Micciche It's doubtful from my perspective that it's going to remain unchanged, but it's a good start. It's a good place to begin some negotiations and a good way to bring more support from the Legislature and the people of Alaska while understanding the value of becoming competitive without giving away Alaska's fair share.

There are a lot of levers in oil tax policy that can affect throughput; remember I've got a pair of glasses on that looks at throughput. We haven't spent enough time with the bill to know if this is the right answer or perhaps if adjusting existing legislation is the right answer. What I can say is that my philosophy is that I don't believe in regressive tax structure. I believe there should be an element of progressivity that at least keeps the proportion of revenue flat through the various price ranges. I agree with eliminating credits that don't lead to increased production, but I would like to see the various committees process potential credits that do lead to increased production. The prime example in the past that doesn't lead to production: paving runways doesn't lead production.

So I agree with the governor's concept of eliminating non productive credits, however we do want to incentivize additional investment and we especially want to incentivize future investment in areas we may not know today contain considerable reserves of North Slope oil.

The realities of any adjustments to taxes in Alaska is that it's not a party issue. Our committee is committed to hearing concerns of all sides of the issue to make sure any reductions in revenue ties directly to companies investing back in Alaska. It's a legitimate concern and it's one that we want a loud message to producers on the North Slope that our only two reasons for a more competitive regime is to encourage those dollars to be invested in this state and to draw quality companies to expand their operations in Alaska.

Petroleum News: On the issue of the natural gas pipeline, what are your views of the status of things, whether it's an LNG export operation or a bullet line?

Micciche: My focus is on energy for Alaskans. Coming right up behind it includes employment, revenue benefits of a larger line. If we cover the part about energy for Alaskans, think about potential for Alaska's young people with the work that could be created from industries that are marginally using diesel as a fuel source and become attractive with lower cost natural gas energy. I envision mines that are marginal today could become more attractive processing facilities. The reduction in cost of operating things like universities and schools and all things that come along with it, that incremental cost reduction of energy, are dollars that can be spent on employing people for more effective education and ultimately more revenue for the state. When we talk about going to a larger diameter line, again, it's a No. 2 product for the state of Alaska immediately that would employ thousands and put us back in the global market place for distributing LNG throughout the Pacific Rim.

Petroleum News: Do you think Alaska is a good export option separate from the Lower 48?

Micciche: Whatever the decisions are about exporting from the Lower 48, it's imperative that Alaska is not included in an export moratorium. Looking at the value of natural gas we do not compete with Henry Hub pricing. We do not affect the gas available to the Lower 48. Restricting exports from Alaska would be an unfair regulatory taking from the people of Alaska.

Micciche: Do you have any final thoughts to offer?

I always have a focus on quality of life issues. I believe in taking care of the folks who need us most: kids, seniors, veterans and the disadvantaged. I absolutely believe that quality education for our young people is key: it must be adequately funded. All of those issues are dependent on a healthy revenue stream.

My top three priorities are: reasonable amount of spending in both the operating and capital budgets; increasing throughput in TAPS; and a statewide energy plan that focuses on rural as well as urban areas with a primary focus on bringing North Slope natural gas to Alaskans first and a global market place second.

I have a pretty incredible life. I have a great family and I enjoy my job as producing LNG. The reason I'm here specifically is to help create opportunities that I enjoyed as a young man. I feel policy issues the last few years essentially stymied what our future can look like for our kids and grandkids.

An important thing to me — and we've been meeting with a lot of groups — what I promise people not only who were here today, but others is that I'm looking to ensure employment for our best and brightest for generations. Without processing these three priorities, the opportunities for these young people, our best and brightest will be working somewhere else. ●

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OIL TAX BILL

development of new oil by eliminating 20 percent of new oil from production taxes. The requirement that carry forward losses may only be applied against production eliminates upfront payouts from the state and focuses on the governor's goal of increasing production.

Investment elsewhere

Why make a change?

High oil prices have meant increased investment elsewhere, but not in Alaska, Pulliam said.

Investment matters because less than half of the oil considered recoverable from the North Slope has been produced to date.

With production to date of 16.2 billion barrels, federal government estimates put remaining oil at 5.6 billion barrels of discovered conventional resources; 19.2 billion barrels of undiscovered conventional resources; 9.9 billion barrels in the Arctic National Wildlife Reserve; and 5.5 billion barrels of unconventional resources.

That's a lot of oil, Pulliam said, but "it's not low-hanging fruit."

It's challenging, it's offshore, and what is onshore "is higher cost and going to be more challenging to get at than the oil we've produced to date."

Impact of ACES

Alaska oil production was taxed under a gross system referred to as ELF for economic limit factor until the Petroleum Profits Tax, PPT, was introduced in 2006.

PPT had a 22.5 percent base tax rate, with progressivity increasing the rate at 0.2 percent per $1 over $40 net, a 20 percent capital credit and a maximum rate of 50 percent.

PPT was amended in 2007 with ACES, which has a 25 percent base net tax rate and progressivity increasing the rate at 0.4 percent per $1 over $30 net, 0.1 percent per $1 over $92.50 net and a maximum rate of 75 percent.

State revenues have grown dramatically under ACES: about $20 billion in additional revenues since it took effect, compared to projected revenues under the old gross system.

Pulliam showed figures for the period under ACES comparing revenues with those projected under PPT and ELF: ACES $26.4 billion; PPT $17.2 billion; the old gross system $6.3 billion.

Capital spending impact

But there has also been an investment impact.

Pulliam said North Slope capital spending came down in the mid-2000s, "started to rise in 2005 as oil prices rose, went up again in '06 and it's come up a little bit since then, but has been relatively flat over the last four or five years" while "capital spending elsewhere has really exploded over that time period."

Of total spending, about 70 percent was by large producers and the remaining 30 percent by all others.

Pulliam also showed capital spending broken out by mature units and new units — those not in production in 2003.

"The increase in the spending has been for those new units," he said, while "... spending at the mature units has been relatively flat."

Drilling, exploration and development, has generally been declining. While some 200 wells a year were drilled in the early 2000s, "we've dropped off: The most recent year is about 150 wells per year," with most of that drilling by majors.

Benchmarking

Econ One benchmarked Alaska activity against OECD, Organization for Economic Cooperation and Development, areas that share many characteristics with the North Slope: similar political and legal structure; similar risk; significant prospectivity, but with much of the "low-hanging" fruit already produced; development of remaining resources largely high cost; and resources developed in large part by the private sector.

Econ One compared the areas — the North Sea, key producing areas in the U.S., Canada and Australia — by production, capital spending, employment and drilling by indexing values based on 2002, allowing comparisons across different production levels.

Production in Alaska has dropped about 50 percent over those 10 years, a decline Pulliam said is mirrored in the North Sea, "an area that was discovered and developed about the same time as Alaska," and shares with Alaska characteristics of being an expensive and difficult area to do business.

He noted the United Kingdom has recently modified its tax structure "to try and attract more investment and get more production" with the result of "announcements of multiple project sanctioning just recently."

Areas in the Lower 48 — Gulf of Mexico outer continental shelf, Texas, California, North Dakota Bakken — all show flattening or increasing production, as does the Lower 48 overall. While California hasn't had an increase in production, there is a "lessening of the decline" as more oil has been produced from mature fields, he said.

A capital spending comparison, also indexed, between Alaska, U.S. and worldwide (Alaska based on North Slope tax return information; U.S. based on top 50 public companies; worldwide based on top 75 companies) shows that while U.S. and worldwide exploration and development spending tended to track oil prices, rising when prices rose in 2006 and 2007, and rising again beginning in 2010, it remained "relatively flat in Alaska," Pulliam said.

Metrics

Econ One looked at a 50 million barrel development, evaluating net present value — the value of the stream of payments expected over time, based on an investment made today, discounted at 12 percent. It looked at internal rate of return, basically a hurdle rate companies used to compare projects; it looked at cash margins, the cash the project is expected to generate; and it looked at net present value to the state of revenues from the project, also at a 12 percent discount rate.

One factor making projects in the Eagle Ford in Texas and the Bakken in North Dakota attractive is that "a large amount of the production comes very quickly, whereas the more traditional wells play out over a longer time period."

In the Eagle Ford, 40 percent of reserves are produced in the first year; in the Bakken it's 30 percent in the first year, Pulliam said. Alaska conventional oil projects produce a little less than 5 percent in the first year, peak at a production rate of about 10 percent and then decline.

System comparison

Under Alaska's old gross tax system, a combination of royalty and tax was somewhere in the 20 percent range, Pulliam said. By comparison, royalty and tax in the Lower 48 is about 30 percent, particularly on private lands.

Because those are gross systems, net present value, NPV, to the producer continues to rise as oil prices rise.

Looking at a hypothetical 50 million barrel field, under ACES the crossover point for NPV — less to the producer — for a new participant is about $80 a barrel; for an incumbent about $100 a barrel. NPVs are higher in the lower price range because of the progressivity built into ACES, Pulliam said.

The cash margins under ACES, while substantially reduced from the gross system, are slightly better for new participants, because Alaska provides "a small producer credit so that gives them a slightly higher margin."

For incumbents, the cash margin is relatively flat under ACES, because while

see **OIL TAX BILL** *page 20*

ENVIRONMENT & SAFETY

Legacy well resolution offered in House

The Alaska Legislature again is considering a resolution calling on the federal government to clean up so-called legacy wells on the North Slope.

State Rep. Charisse Millett, R-Anchorage, introduced House Joint Resolution 6 on Jan. 28.

The resolution is similar to the one that passed with overwhelming support in both the House and Senate during the 2012 session.

A resolution does not carry the same weight as a bill that can become law. Rather, a resolution merely expresses legislative sentiment.

The legacy wells are in the National Petroleum Reserve-Alaska. Federal departments drilled more than 135 wells between 1944 and 1982.

The Bureau of Land Management is now responsible for the NPR-A and the old wells.

Some Alaska officials, including Millett and Cathy Foerster, chair of the Alaska Oil and Gas Conservation Commission, say BLM has neglected numerous legacy well sites and failed to properly plug and abandon the holes.

"Hardly any progress was made last year and that will continue as long as the agency fails to create an aggressive cleanup plan and back it up with adequate funding," Millett said in a Jan. 29 press release.

BLM officials have said they're developing a plan to assess the legacy wells. And they've said they doubt any are posing a hazard.

HJR 6 has been referred to the House Resources Committee.

It calls for BLM to not only plug and abandon the legacy wells, but to open new areas of the NPR-A for "environmentally responsible oil and gas development."

—WESLEY LOY

Oil Patch Bits

Totem Equipment & Supply has new generator system

Totem Equipment & Supply said Jan. 15 that it is announcing the development of a 90KW prime power natural gas powered generator system.

The RCI-100NG-90 is specifically targeted towards the oil field. The Totem90 has available a sophisticated pipeline dehydrator system that pulls the moisture and solid particles out of the gas. The clean and dry gas is then regulated down to the proper pressure and volume to power the generator.

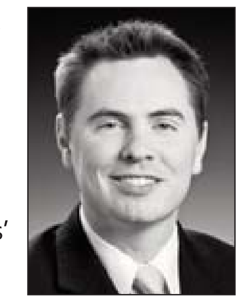
The generator supplies a full 90 kilowatts of continuous duty electricity fueled by the natural gas already available on site. The benefits include fuel savings, transportation savings, elimination or reduction of flaring issues, and a continuous and reliable power supply.

This unit comes standard in a weather proof enclosure, skid mounted for ease of placement. Available options are distribution systems and the dehydrator.

ASRC Energy Services hires Whitley as general counsel

ASRC Energy Services said Jan. 16 that it has hired Joel Whitley as general counsel. Whitely joins AES and its family of companies from Arctic Slope Regional Corp. where he served as senior corporate counsel.

Before coming to Alaska, Whitley was an attorney at the law firm of Munger, Tolles & Olson in Los Angeles. He earned a bachelor's degree in industrial and systems engineering from Georgia Tech followed by a law degree from the University of Chicago.



JOEL WHITLEY

ASRC Energy Services also promoted Alan Growden to general manager of its E&P Technology subsidiary, which provides high-end technical consulting, project management, and on and off-site planning to the oil and gas industry. In addition to his new role, he will also continue as the senior business analyst for ASRC Energy Services' professional services group which includes regulatory and technical services, engineering, E&P technology and response operations.

Growden has been with the AES family of companies since 1994.

AES has been operating since 1985 and employs close to 5,000 people working in more than 30 states. AES is a leading oil and gas service company with headquarters in Anchorage, Alaska, and is the largest private employer in the state, with annual revenues of approximately $635 million.

ASRC executive named to Arctic Oil Spill Committee

Arctic Slope Regional Corp. said Jan. 29 that Richard Glenn, its executive vice president

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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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GAS PERSPECTIVES

committee meetings around the theme of "who's keeping the lights and heat on," hearing presentations from DNR and the utilities, to gain a clearer understanding of the gas supply situation. During one of these meetings, a House Energy Committee meeting on Jan. 23, Rep. Charisse Millett, R-District 24, expressed the frustration that some lawmakers and others feel.

"It's very concerning that we have two groups of people that one says we're awash with gas in the Cook Inlet and then another group saying that we have gas and that we're just not producing enough of it," Millett said. "So it's disturbing for those of us who live in the Cook Inlet (region) because this has been the ongoing debate between the (state) administration and what the utilities have been saying."

DNR: shared concern

During presentations to the Senate Resources Committee on Jan. 21 and to the Regulatory Commission of Alaska on Jan. 23, DNR Commissioner Dan Sullivan said that DNR shares the utilities' concerns about potential shortfalls in the delivery of gas to Southcentral consumers and power plants. But, while there are legitimate concerns about the amount of gas that the utilities have available under secure contracts with Cook Inlet gas producers, DNR, as manager of the state's gas resources, takes a much broader view of the situation, Sullivan said.

"We also think there are still large volumes of oil and gas in the inlet, not maybe in huge fields, but in intermediate fields, and we think that's important," he said. "We've been focusing on that view."

Sullivan said that DNR has seen success in encouraging companies such as Hilcorp Energy and Apache Corp. to come to Alaska to seek and develop some of the substantial oil and gas resources that the state believes remain in the basin. The Cook Inlet basin is currently seeing something of a renaissance in oil and gas exploration and development.

So, what is the situation on the future prospects for continuing Cook Inlet gas supplies?

Production studies

The state has conducted studies into how much gas might be available for production from the basin. And independently from the state, the utilities commissioned consultancy firm Petrotechnical Resources of Alaska, or PRA, to assess the situation. As a starting point, both DNR and PRA used a technique called decline curve analysis, projecting the rate of decline of gas production from currently operational gas wells and gas fields to predict the future decline in gas production from the basin as a whole. Both DNR and PRA came to almost identical conclusions: In the absence of new gas wells, gas production will drop below gas demand around 2013 to 2014.

But, on the assumption that gas producers will continue to drill more wells, DNR and PRA have taken different approaches to evaluating how much gas might in reality be produced from the Cook Inlet basin in the coming years. DNR has assessed how much gas could be available for development, regardless of how long that development might take or how much it might cost, while PRA has evaluated the extent to which feasible rates of new gas well drilling might impact the gas production decline.

DNR techniques

DNR used two techniques to assess how much gas people might reasonably expect to see come from the basin as gas field development continues, Paul Decker, a petroleum geologist with Alaska's Division of Oil and Gas, explained to the RCA commissioners on Jan. 23.

The first of these techniques, called "material balance," uses changes in gas field reservoir pressures over time, as gas is produced, to estimate how much gas remains in pressure contact with producing gas wells. The use of this technique expands by about 32 percent the gas volume estimated from decline curve analysis, Decker said.

The second technique involves a geologic analysis, mapping known reservoir horizons to estimate volumes of gas that are likely to lie trapped underground.

Uncertainties

Decker also explained the importance of assessing uncertainties when using these techniques. Undeveloped gas can broadly be categorized as reserves, gas proved to exist from drilling and economic to produce, and resources, gas not proved from drilling or not shown to be economically viable, he said. And within those categories there are statistical ranges of uncertainty in gas volume estimates.

Decker said that for the most part DNR does not have access to companies' reserves estimates, the volumes that the companies use when making decisions over gas sale contracts with utilities. But DNR views the volume estimates obtained from decline curve analysis as high probability reserves and the estimates from material balance as medium probability reserves. The volume estimates obtained from geologic analysis include some reserves, as well as less certain gas resources including some gas that would be discovered from exploration.

Remaining reserves

Overall, DNR has estimated that there remain about 1.1 trillion cubic feet of producible gas reserves in the 28 existing fields in the Cook Inlet basin, Decker said. The geologic analysis indicates another 355 billion cubic feet of natural gas in undeveloped areas of existing fields, mainly in three large fields: the Beluga River field, the Trading Bay unit Grayling Gas Sands and the North Cook Inlet field, he said. Further gas estimated from the geology would be found as a result of future exploration.

And, while DNR does not disagree with PRA's view that there is a shortage of gas under utility contract, the gas resources in the basin are not depleted, Decker said. A plot of all of DNR's reserves and resource estimates relative to anticipated Cook Inlet gas demand indicates that there may be enough gas in basin to meet gas demand through to the late 2020s, if enough drilling is done.

"What it reflects is that not enough wells are being drilled fast enough to keep pace with demand," Decker said. "We believe that there's significant gas left in the basin."

Marathon contract

On Jan. 21 Deputy Commissioner of Natural Resources Joe Balash told the Senate Resources Committee that the drilling required to sustain Cook Inlet gas supplies requires adequate commercial incentives. Balash recounted events in 2005 when the Regulatory Commission of Alaska rejected a proposed gas supply contract between Marathon Oil Co. and Enstar, following concerns about proposed price rises in the contract, with opposition to the contract from a number of entities including the state Attorney General's Regulatory Affairs and Public Advocacy Section.

The rejection of that contract sent a chill through the Cook Inlet industry, was followed by a dramatic drop in drilling activity and may have triggered Marathon's eventual departure from Alaska, Balash said. But that contract, which had prices indexed to the Lower 48 Henry Hub market, would have met all of Enstar's gas needs through 2016, including seasonal swings in gas demand. Ironically, given a subsequent fall in Henry Hub prices that no one predicted in 2005, gas prices in the Marathon contract would have dropped rather than risen.

But Marathon's willingness to commit to that contract demonstrates that the company had sufficient gas to meet Enstar's needs for the duration of the contract, Balash said.

"We're not out of gas," Balash said. "Marathon would not have put its corporate reputation and balance sheet on the line if they didn't think there were sufficient reserves to meet all of the requirements."

PRA analysis

PRA, in its forecasts, has not made any attempt to estimate as-yet undeveloped gas volumes in the basin. Instead, on the assumption that there is more gas to develop, either in existing fields or from gas exploration, the PRA analysis has evaluated the rate of gas-well drilling required to overcome the gas supply decline. And, by considering the numbers of wells that have been drilled each year in the past and then evaluating how much drilling might realistically take place in coming

see GAS PERSPECTIVES page 18

Stored gas now crucial for utilities

The new natural gas storage facility, known as Cook Inlet Natural Gas Storage Alaska, or CINGSA, that went into operation in the spring of 2012 on the Kenai Peninsula, is proving vital to Southcentral Alaska utility gas supplies as, for the first time, the ability of the Cook Inlet gas fields to deliver utility gas fast enough during periods of winter cold has dropped below the gas deliverability needs.

December needs

During a presentation to the House Energy Committee on Jan. 23 Moira Smith, vice president and general counsel of Enstar Natural Gas Co., explained how during especially cold weather in mid-December Enstar, the main Southcentral gas utility, had withdrawn gas stored in CINGSA to meet the utility's daily gas needs. Enstar had warehoused the gas in CINGSA during the summer, when gas demand was relatively low.

Enstar now finds itself in a situation where it has insufficient gas supplies under firm contract with gas producers to fully meet its needs. The company has been operating a daily bidding system, soliciting several producers to bid daily quantities of gas to fill Enstar's supply shortfalls. But, with the bid gas proving insufficient to fill all of the supply gaps, Enstar has had to take some of its gas from storage.

On Dec. 17, for example, the total system demand was 225 million cubic feet of gas, and Enstar was able to fill some of its supply shortfall from bid gas, Smith said.

"We paid not insignificant amounts for that gas and we still had to dip into CINGSA to the tune of 60 million (cubic feet) for that day," Smith said.

Less than planned

Smith told the lawmakers that because of tight Cook Inlet gas supplies during 2012, Enstar had not been able to obtain all of the gas that it intended to store for the winter. As of Jan. 18 Enstar had 3.4 billion cubic feet of gas in CINGSA, Smith said.

The CINGSA facility itself has been unable to obtain all of the gas that it had planned to use as pad gas, the gas that is permanently stored in the facility to maintain the gas pressure in the underground storage reservoir. The consequent lack of full pressure in the reservoir slightly degrades the storage facility's contracted withdrawal rate of 136 million cubic feet per day, Smith said. So far this winter Enstar's highest daily withdrawal rate has been 70 million cubic feet, she said.

Two other utilities — Chugach Electric Association and Municipal Light & Power — also use the CINGSA facility. Smith said that Chugach Electric had also been unable to obtain all of the gas that it had planned on storing, but that ML&P had eventually obtained all of its gas.

No wiggle room

Given the tight gas supply situation, a production failure in a gas field or a problem with one of CINGSA's gas compressors would trigger a need to generate power from diesel generators, Smith said. ML&P has a back-up diesel generation system. Also, if March turns out to be unseasonably cold, Enstar could entirely deplete its CINGSA gas and thus be unable to meet its peak deliverability needs, Smith said.

Smith told the Senate Resources Committee that, without the gas demand flexibility provided in the past by liquefied natural gas and fertilizer facilities on the Kenai Peninsula, there is no longer any slack in the system.

"We're counting on production to be exactly what we need to meet Cook Inlet demand, and that's a big risk, because on any given day production hiccups can occur, CINGSA's compressors could go down," Smith said.

LNG exports

During the Senate Resource Committee meeting Sen. Fred Dyson, R-District F, asked utility officials whether the export of gas through the Kenai Peninsula liquefied natural gas plant had contributed to the difficulty of delivering sufficient gas to CINGSA. Bradley Evans, CEO of Chugach Electric, said that, while there had been difficulties in balancing the needs of various gas supply contracts during the summer, gas exports had not occurred as the same time as the problems in obtaining CINGSA gas.

"It's just another demonstration that there's been a decline in the Cook Inlet and it gets more and more difficult to meet the needs of all the people that want the gas," Evans said.

—ALAN BAILEY

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GAS PERSPECTIVES

years, the PRA study sought to forecast future gas production using likely future drilling rates.

PRA sees the possibility of at least three new gas well completions each year, with the realistic possibility of as many as eight wells per year and a likely drilling rate somewhere in the middle of that three to eight range, PRA consultant Bill Van Dyke told the House Energy Committee on Jan. 23. Based on typical gas production rates from new Cook Inlet wells, the anticipated drilling rate suggests an addition of 10 million to 20 million cubic feet of gas production each year, but with the new wells themselves going into decline after startup. Adding up the numbers and projecting the production rates forward leads to that prediction of a supply shortfall around 2014-15.

And to enter into gas supply contracts with utilities, gas producers need proven reserves, not uncertain resource estimates.

"Would you bet the energy security of your community on the speculative prospects of major gas finds in the Cook Inlet and major gas development at this time?" Rep. Mike Hawker, R-District 27, asked Van Dyke.

"No, I would not," Van Dyke replied. "Utilities need a guaranteed gas supply. A probabilistic study of how much gas is in Cook Inlet is not a guaranteed gas supply."

Timing

Van Dyke also commented on the timing issues associated with bringing a new gas field on line. In a simplest case, say on the Kenai Peninsula, it might take two to three years to complete all of the planning, permitting, contract negotiations and development involved in bringing a new field into production, he said. That would bring new gas from the new field into the gas infrastructure after the date of the projected gas supply shortfall.

And if gas producers accelerate the rate of drilling in the existing fields, the effect would be to accelerate the production decline rates in the fields, thus further reducing production rates a few years down the road. Essentially, people are trying to deal with a set of gas fields, all undergoing a natural production decline, Van Dyke said.

"We're showing a 16 or 17 percent annual decline and that's a pretty steep decline rate to chase," Van Dyke said. "You're going to have to find a lot of new gas just if you want to keep production flat, let alone increase it, because you have this base that's always in natural decline."

Enstar: the bottom line

Moira Smith, vice president and general counsel of Enstar Natural Gas Co., told the Energy Committee that Enstar has been supplying Southcentral residents with gas since 1961, using only Cook Inlet supplies.

"It is Enstar's primary goal to continue to do that, and to do that at a price that's reasonable for Southcentral customers," Smith said.

But, with a gas supply shortfall on the horizon, the utilities are taking steps to bolster Southcentral energy supplies from other sources, she said.

"We've reached the bottom line, which is that we need to supplement Cook Inlet gas production," Smith said. ●

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Utilities still deciding on gas solution

The Southcentral Alaska power and gas utilities are still assembling the information they need to decide on how to deal with pending shortfalls in utility gas supplies from the Cook Inlet basin. The utilities anticipate the total supplies of utility gas from the basin to fall short of annual demand around 2014-15 and are anticipating having to bolster those supplies from other energy sources.

Although there is a proposal to build a gas line to bring North Slope gas into Southcentral, this line cannot come into operation in time to head off the gas shortfall and it is not yet known whether the line will in fact be built.

Utility group

Members of the Long Term Gas Supply Study Group, a group of utility executives that has for several years been assessing the looming gas supply crisis and determining how to deal with it, talked to the Alaska House Energy Committee on Jan. 23.

The utilities are seeking a short-term fix that can head off any energy shortage in, say, a couple of years' time, and a longer-term, perhaps more cost-effective, solution that can provide future supply flexibility, on the assumption that Cook Inlet supplies will remain tight. Unlike gas markets elsewhere in North America, the Cook Inlet gas market is isolated, with no current means of obtaining gas from elsewhere, should local supplies fall short.

The utilities have received information on possible solutions to the gas supply problem from three companies that could potentially bring compressed natural gas to Southcentral by sea from elsewhere, and from three potential liquefied natural gas providers, Moira Smith, vice president and general counsel of Enstar Natural Gas Co, told the Energy Committee. The utilities are also considering the option of trucking LNG from the North Slope, Smith said.

Cost challenges

Ideally, the utilities would like a solution that would avoid discouraging new Cook Inlet gas production while being scalable to market needs, with the option to turn the spigot off if new Cook Inlet gas comes on line, Smith said.

But, achieving those ideal objectives would be very expensive, primarily because of the high cost of amortizing project costs over a short timeframe, Smith said. The utilities have previously said that any marine import option would likely involve the construction of ships.

"Any import project would involve capital investments that would have to ideally be amortized over a significant period of time," Smith said. And any "escape clause" in the contract, allowing the contract to be terminated, would be very expensive, she said.

Diesel?

The utilities have been considering the use of diesel power generation as a short-term measure when the utilities run short of gas. Anchorage utility Municipal Light & Power has standby diesel generation capacity, but Chugach Electric Association, the other main supplier of gas-fired power, has no generators that can run on diesel.

Jim Posey, general manager of ML&P, cautioned that ML&P's diesel generation system is more than 35 years old and would have to be shut down every five or six days for maintenance, were it to be needed on a continuing basis. The utilities are considering retrofitting diesel generation capabilities into a new gas-fired power plant that is about to come into operation in south Anchorage. But a retrofit of this type would run into issues with the facility's air quality permit, Posey said.

The utilities are also considering the possibility of spot market liquefied natural gas purchases as a short term measure, Smith said.

State's concerns

During a presentation to the Regulatory Commission of Alaska on Jan. 23 Dan Sullivan, commissioner of the Alaska Department of Natural Resources, expressed the state administration's concerns with the concept of importing gas into Alaska from elsewhere. The import of gas could undermine the economics of local gas production in the Cook Inlet, and could result in reducing the state's credibility as a liquefied natural gas exporter relative to other gas producing regions, especially western Canada, Sullivan said.

Sullivan said that the state administration does support the concept of building an in-state pipeline from the North Slope to Southcentral.

Room for CI producers

In response to questions during an Alaska House Energy Committee meeting on Jan. 23, Bill Van Dyke, a consultant with Petrotechnical Resources of Alaska, the firm that has been assessing the gas supply situation for the utilities, said that he did not think that imported gas would put Cook Inlet gas producers out of business.

"Exploration and production in the Cook Inlet is always going to be competitive against the price of imported gas," Van Dyke said. Van Dyke also said that trucking liquefied natural gas from the North Slope would present a huge challenge, given the hundreds of trucks that would need to ply the route to Southcentral.

Asked whether he thought there is a political dimension to an aversion to importing gas to Alaska, Van Dyke alluded to the potential for power blackouts if Southcentral runs short of gas.

"Maybe importing gas to Alaska gives us a bit of a black eye," Van Dyke said. "I'm not sure whether it does or whether it doesn't. But if it's a choice between a black eye and a blackout, I'll take the black eye."

—ALAN BAILEY

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CONOCO EARNINGS

ments. Alaska continues to be the most productive oil region for the company, but the Lower 48 is on pace to overtake the Last Frontier within the next two years.

"The fourth-quarter earnings continue the general trend where we pay twice as much in taxes as we keep," Bob Heinrich, the vice president of finance for ConocoPhillips in Alaska, said in a statement on Jan. 31. "We are hopeful that the Governor and legislature will be successful in creating a better business climate on the North Slope."

The annual figures are the first since ConocoPhillips split itself into separate upstream and downstream units in May 2012, becoming the largest independent in the country.

Earnings up

ConocoPhillips' earnings in Alaska rose both year-over-year and quarter-over-quarter.

The company earned $570 million in the fourth quarter, up 6.5 percent from $535 million in the third quarter and up 34 percent from $426 million in the fourth quarter of 2011.

Including a $25 million adjustment in the fourth quarter for "pending claims and settlements," ConocoPhillips earned $595 million in Alaska in the fourth quarter.

By comparison, ConocoPhillips reported adjusted earnings of $630 million in the Lower 48 in 2012, down from $1.08 billion in 2011 because lower commodity prices. In the fourth quarter, ConocoPhillips earned $147 million in the Lower 48, up from $145 million in the third quarter, but down from $317 million in the fourth quarter of 2011.

In Canada, ConocoPhillips reported a net loss of $122 million in 2012, down from adjusted earnings of $270 million in 2011. In the fourth quarter, ConocoPhillips reported adjusted earnings of $32 million in Canada, up from a net loss of $31 million in the third quarter but down from adjusted earnings of $92 million in the fourth quarter of 2011.

Companywide, ConocoPhillips reported adjusted earnings of $6.7 billion for the year and $1.7 billion for the quarter, down from nearly $8 billion in 2011 and $2 billion in the fourth quarter of 2011. The company attributed the drop to lower prices and production.

Revenues and taxes

Like its earnings, ConocoPhillips' revenues in Alaska also increased in 2012.

ConocoPhillips earned more than $3.5 billion in the state before income taxes in 2012, up 12 percent from more than $3.1 billion in 2011. For the fourth quarter, ConocoPhillips earned $882 million in Alaska before income taxes, up 7.5 percent from $820 million in the third quarter and up 27.6 percent from $691 million in the fourth quarter of 2011.

By comparison, ConocoPhillips earned more than $1.1 billion for the year and $279 million for the quarter before income taxes from its Lower 48 and Latin American segment, down from $2 billion for 2011 and $477 million in the fourth quarter of 2011.

Although revenues and earnings rose in Alaska, the tax rate dropped slightly.

In Alaska, ConocoPhillips reported an average effective tax rate of 35.8 percent for 2012, a figure that jumps to 62.5 percent when non-income taxes are included. For 2011, ConocoPhillips reported effective tax rates of 37.1 percent and 66.5 percent respectively.

The two figures put Alaska in the middle of the ConocoPhillips portfolio.

ConocoPhillips reported an effective tax rate of 11.4 percent from the Lower 48 and Latin America in 2011, but the figure is unusually low because of special tax items reported toward the end of the year. For much of 2012, ConocoPhillips reported a tax rate for the Lower 48 and Latin America segment between 38.3 percent and 42.6 percent.

Both of the figures ConocoPhillips reported for Alaska are higher than what it reported for Canada (26.9 percent) and the Asia Pacific and Middle East segments (28.3 percent), but lower than Europe (72.8 percent) and "other international" segments (80.5 percent).

ConocoPhillips only breaks out a non-income tax rate for Alaska.

While the tax rate fell, the total obligations in Alaska more than doubled earnings.

ConocoPhillips said it paid $3.7 billion in state taxes and royalties and $1.2 billion in federal taxes in 2012. The company said its 46,000-barrels-of-oil-equivalent production increase in the fourth quarter yielded $250 million in additional state obligations.

Spending up, but…

ConocoPhillips spent more in Alaska in 2012 than it did in 2011, but its investment in the state remains far below other regions in its portfolio and only a sliver of overall spending.

ConocoPhillips reported $828 million in spending in Alaska in 2012, up from $775 million in 2011. For the fourth quarter, the company said it spent $232 million, up from $208 million in the third quarter and $190 million during the fourth quarter of 2011.

By comparison, the nearly $15 billion capital program for 2012 included more than $5.2 billion in the Lower 48 and Latin America, more than $2.8 billion in Europe, more than $2.4 billion in the Asia Pacific and the Middle East and nearly $2.2 billion in Canada.

ConocoPhillips reported $516 million in Depreciation, Depletion and Amortization expenses in Alaska in 2012, down from $576 million in 2011. For the fourth quarter, ConocoPhillips reported $131 million in DD&A expenses in Alaska, up from $117 million in the third quarter but down from $155 million in the fourth quarter of 2011.

"We could make other significant investments in Alaska, but they will require more competitive state fiscal terms," Matt Fox, executive vice president of exploration and production, told analysts during a quarterly earnings teleconference on Jan. 31.

While the Alpine West, or CD-5, project represented a major spending bump last year, ConocoPhillips also touted an "octo-lateral" well drilled in 2012, or a development well with eight horizontal laterals, believed to be the first of its kind on the North Slope.

When asked whether he thought state lawmakers would change the fiscal regime this year, CEO Ryan Lance said he was "probably slightly encouraged." While praising Gov. Sean Parnell for leading the effort to make Alaska more "competitive" for oil industry investment, Lance noted, "It's going to be a tough haul through the Legislature."

Production keeps falling

The higher earnings mask declining production for ConocoPhillips in Alaska.

Across all commodities, ConocoPhillips produced 213,000 barrels of oil equivalent per day in Alaska in 2012, down 5 percent from 225,000 boe per day in 2011. For the fourth quarter of the year, the company produced 222,000 boe per day, up 26 percent from 176,000 boe per day in the third quarter because of turnarounds from seasonal fieldwork, but down 6.3 percent from 237,000 boe per day produced in the fourth quarter of 2011.

Those production figures place Alaska behind the Lower 48 and Europe, but ahead of Canada for production. In the Lower 48, ConocoPhillips produced 457,000 boe per day in 2012, up 6.7 percent from 428,000 boe per day in 2011. In Europe, ConocoPhillips produced 228,000 boe per day in 2012, down 18 percent from 279,000 boe per day in 2011. In Canada, ConocoPhillips produced 192,000 boe per day in 2012, down 5.4 percent from 203,000 boe per day in 2011. Companywide, ConocoPhillips produced 1.58 million boe per day in 2012, down 2.5 percent from 1.6 million boe per day in 2011.

Even with the continued declines, Alaska remains the most productive segment in the ConocoPhillips portfolio for crude oil. The company produced 188,000 barrels of crude oil per day in Alaska in 2012, down 6 percent from 200,000 bpd in 2011. In the fourth quarter, ConocoPhillips produced 196,000 bpd in Alaska, up 25 percent from 157,000 bpd in the third quarter but down 6.6 percent from 210,000 in the fourth quarter of 2011.

The Lower 48, though, is the fastest growing segment. In 2012, ConocoPhillips produced 123,000 bpd from its Lower 48 operations, up from the 94,000 bpd in 2011. The 30 percent increase was almost entirely attributed to growing production from two unconventional plays: the Eagle Ford of South Texas and the Bakken of North Dakota.

In Europe, ConocoPhillips produced 135,000 bpd in 2012, down nearly 17 percent from 164,000 bpd in 2011. In Norway, ConocoPhillips produced 104,000 bpd in 2012, down nearly 9 percent from 114,000 in 2011. Companywide, ConocoPhillips produced 618,000 bpd of crude oil in 2012, down nearly 5 percent from 650,000 bpd produced in 2011.

While oil production continued to decline in 2012, Alaska natural gas liquids stayed flat.

ConocoPhillips produced 16,000 bpd of natural gas liquids in Alaska in 2012, up slightly from 15,000 bpd in 2011. In the fourth quarter, the company produced 17,000 bpd of NGLs, up from 10,000 bpd in the third quarter, but level from the fourth quarter of 2011.

In the Lower 48, ConocoPhillips produced 85,000 bpd in 2012, up from 74,000 bpd in 2011. In Canada, ConocoPhillips produced 24,000 bpd, down from 26,000 bpd in 2011.

Just like its legacy North Slope oil fields, ConocoPhillips' legacy Cook Inlet gas fields are declining. ConocoPhillips produced 55 million cubic feet of gas per day in Alaska in 2012, down nearly 10 percent from 61 mmcf per day in 2011. In the fourth quarter, the company produced 56 mmcf per day, up nearly 10 percent from 51 mmcf per day in the third quarter but down 5 percent from 59 mmcf per day in the fourth quarter of 2011.

As ConocoPhillips increasingly weights its portfolio toward oil, other segments saw gas decline in 2012. In the Lower 48, ConocoPhillips produced 1.49 billion cubic feet per day in 2012, down from 1.55 bcf per day in 2011. In Canada, ConocoPhillips produced 857 mmcf per day in 2012, down from 928 mmcf per day in 2011. Companywide, ConocoPhillips produced 4.2 Bcf per day in 2012, down from 4.5 Bcf per day in 2011.

ConocoPhillips is earning more from its Alaska commodities, though.

While reporting a realized oil price of $109.62 per barrel in Alaska in 2012 (up from $105.95 per barrel in 2011), ConocoPhillips reported a price of $91.67 per barrel in the Lower 48 (down from $92.79) and $78.26 per barrel in Canada (down from $86.04).

And because Alaska natural gas prices are set on contracts, rather than on the spot market, ConocoPhillips saw an average Cook Inlet gas price of $4.22 per thousand cubic feet in 2012 (down from $4.56 per mcf in 2011), compared to $2.67 per mcf in the Lower 48 (down from $3.99) and $2.13 per mcf in Canada (down from $3.46 per mcf). ●

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LNG RACE

complete a feasibility study to identify long-term sources of natural gas supplies and off-take buyers in Asia.

Stein said AltaGas and Idemitsu have no thoughts of combining with other projects or taking on additional partners.

If LNG shipments do start in 2017, the JV will trail only BC LNG Export Co-operative which said its Douglas Channel project plans to start exporting 1.8 million metric tons a year in spring 2015 — a year behind schedule.

None of the bigger LNG projects on the table in Canada, including Chevron-operated Kitimat LNG, Shell's LNG Canada partnership, Pacific Northwest LNG by Petronas-owned Progress Energy, plans to come on stream before 2018-20, while BG Group and ExxonMobil are in the early stages of feasibility studies.

Pipeline in place

Stein said AltaGas' wholly owned Pacific Northern Gas pipeline is already in place linking Spectra Energy's transmission system from gas fields in northeastern British Columbia with Pacific Coast ports at Prince Rupert and Kitimat.

She said the PNG line has current daily capacity of 115 million cubic feet and is carrying only 30 million cubic feet, with the Kitimat LNG project partners holding an option for 80 million cubic feet.

A feasibility study is already under way to add another 170,000-195,000 million cubic feet to the pipeline and "if all goes to plan" capacity could be raised to 600,000 million cubic feet by 2017, she said.

Stein said the partners will choose between either a floating or land-based LNG/LPG terminal as part of the study after weighing the capital costs and risk-returns.

Stein said the partners will choose between either a floating or land-based LNG/LPG terminal as part of the study after weighing the capital costs and risk-returns.

AltaGas said it is committed to "engage and work effectively with governments, First Nations and other stakeholders."

That pledge coincides with word from aboriginal leaders that LNG projects will be added to crude oil pipelines on their list of projects they will oppose unless they are fully consulted and approve the plans.

In a statement issued by the Carrier Sekani Tribal Council, several chiefs are demanding the right to assess how the projects would affect their environmental and native title rights.

Chief Reg Louis said the Canadian government has stripped environmental protections to make it easier for resource projects to proceed.

The Carrier Sekani statement points to a disagreement with the coastal Haisla Nation, which has signed an agreement that would allow construction of the Kitimat LNG facility as part of plans to export LNG to Asia.

—GARY PARK

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OIL PATCH BITS

of lands and natural resources, has been selected to join the Arctic Oil Spill Committee, a 14-member panel assembled by the National Research Council, out of Washington, D.C.

The NRC is a private, nonprofit institution and a branch of the National Academies, which includes the National Academy of Sciences, National Academy of Engineering and Institute of Medicine.

"I'm honored to have been confirmed as a member of this committee," said Glenn. "As Arctic oil exploration continues off of Alaska's Arctic coast, it's important that we have a clear assessment of the entire spectrum of prevention, preparedness and spill response. As a student of the Arctic environment, and a resident of the North Slope community, I look forward to being part of this team."

The committee is tasked with assembling a report assessing the current state of the science regarding oil spill response and environmental assessment in the Arctic. The report will include looking into various spill scenarios that could be unique to the region as well developing baselines that would be used to shape future decisions in the case of a spill.

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OIL TAX BILL

Alaska provides "a lot of incentive upfront, we take a lot, particularly as prices go up ... with the progressivity," Pulliam said.

Government take is higher for new participants than for incumbents because the new participant can't shelter income before production begins, but once it begins production is subject to the same progressive tax rate, "so it doesn't get the bump at the front end but it's got to pay the price as production starts," Pulliam said.

The "bump" is the result of two things: When you invest you get a credit, "but the other thing that happens is additional spending reduces your tax rate; it reduces it on all of your production," and because of progressivity as prices go higher, "the level of that reduction gets higher and higher."

The governor's proposal

The governor's proposed changes — elimination of progressivity and capital credits and the state's purchase of credits and losses and establishment of a 20 percent gross revenue exclusion for new oil — provides a balance, Pulliam said, by reducing tax rates at high prices, balanced with elimination of credits.

"The state does continue to receive, at any price level, the highest percentage of the revenue from the oil production," he said.

Pulliam also said that because it remains a net system, the proposed changes maintain "the alignment between the state take and the producers' incentives and their operations."

He said he thinks the proposed system provides "a good incentive for new development without taxing the state treasury along the way and having to fund that new development," while the gross revenue exclusion "offers the lower effective tax rate for new development."

The proposal also "sends a very positive message to potential investors," he said.

While the new proposal is "relatively neutral" it is somewhat regressive (lower percentage of take at higher prices) because the state's royalty is taken on the gross.

Pulliam said the goal "was to have a government take that was competitive with what is available elsewhere and that range is generally viewed ... if you look at these other areas that are having success ... somewhere in that 60 to 65 percent range." He said that "you get too much above that range and the investment measures don't fare as well."

Overall, Pulliam said, the governor's proposal — both for NPV and for cash flow — would put the state right "in the game with what's available in the Lower 48."

The 50 million barrel project

For the 50 million barrel project Econ One used as an example, the incumbent has larger total cash flows, $1.544 billion, than under ACES ($1.120 billion), but the NPV at a 12 percent discount is similar: $319 million under the governor's proposal compared to $322 million under ACES. Pulliam said that is because the state won't be subsidizing initial work, so the incumbent will have a larger cash outlay at the beginning.

On the state side, there is a big difference in total revenues, but almost none in NPV, again because the state isn't subsidizing development: $1.612 billion under the governor's proposal, compared to $2.264 billion under ACES, but with NPV of $449 million under the governor's proposal compared to $444 million under ACES.

The state's cash flows are going to be lower, "but the NPV of those cash flows is going to be about the same. So we won't be paying out large sums up front, but we'll be collecting less — at least at this price level ($100 per barrel West Coast ANS) on an ongoing basis."

Pulliam said the governor's proposed tax changes would benefit new participants who are "disadvantaged in many respects right now, because they don't have ... the ability to buy down their tax rate," and so can't have the same internal rate of return or NPV numbers an incumbent can have.

Under the governor's proposal the new participant would have a cash flow of $1.603 billion, compared to $998 million under ACES, and an NPV of $318 million compared to $203 million under ACES.

The state would have total revenues from a new participant under the proposal of $1.521 billion compared to $2.452 billion under ACES, and an NPV of $451 million under the proposal compared to $627 million under ACES.

Overall, Pulliam said, the governor's proposal — both for NPV and for cash flow — would put the state right "in the game with what's available in the Lower 48."

"It's a significant improvement from where we've been," he said. ●

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