Petroleum news

page 21 Breaking News: Shell to appeal court ruling; cancels 2009 Beaufort work

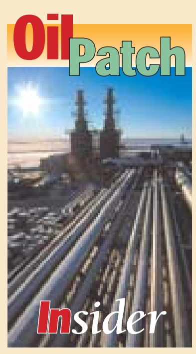
Vol. 13, No. 51 • www.PetroleumNews.com | *A weekly oil & gas newspaper based in Anchorage, Alaska* | Week of December 21, 2008 • $2

Happy Holidays!

JUDY PATRICK

Christmas tree at Peak Base camp in Deadhorse, Alaska

ConocoPhillips wants to reduce costs in Alaska; Alliance moves offices downtown



THE RAPIDLY CHANGING ECONOMIC climate is forcing oil companies to reassess spending plans, but as the year winds down it remains unclear how those reassessments will impact Alaska in 2009.

ConocoPhillips Alaska recently warned employees that uncertainty in oil prices would force cost cutting, according to a report on Dec. 11 from NBC-affiliate KTUU news in Anchorage.

"Our entire business plan was discussed in a broad sense, and was not focused only on employees," company spokeswoman Natalie Lowman told KTUU and later confirmed with Petroleum News.

While the announcement might have caused anxiety around the oil patch, the report lacked a bit of moderately

see **INSIDER** *page 22*

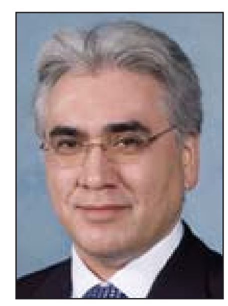
BREAKING NEWS

NATURAL GAS

North in a rage

NWT leaders lash out at latest regulatory delay in Mackenzie Gas Project

By GARY PARK
For Petroleum News



FLOYD ROLAND

Canada's northern political leaders may have finally snapped over the unending regulatory delays in dealing with the Mackenzie Gas Project application.

Word that the Joint Review Panel, responsible for examining the environmental and socio-economic aspects of the C$16.2 billion venture, needs another year to complete its work has pushed those hoping to benefit from Arctic resource development past the breaking point.

Northwest Territories Premier Floyd Roland told the Globe and Mail he is "really quite concerned. … It's a delay on another delay and we've not got a clear answer as to why. It has shaken the confidence of the business community."

He said JRP needs to bring its work to a rapid conclusion so that the various stakeholders can get on with their work and the MGP partners can proceed with a "huge investment that benefits the rest of Canada."

Nellie Cournoyea, a former NWT premier and now chairman of the Inuvialuit Regional Corp., said the latest splutter is "devastating. … It's incomprehensible that a process like this would take so long."

see **NWT RAGE** *page 24*

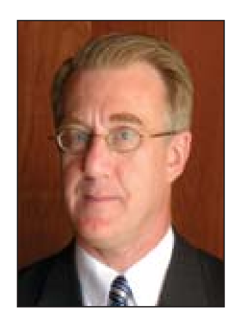
NATURAL GAS

TC tempers loan talk

TransCanada hasn't decided to ask for increase, would only be to cover inflation

By ERIC LIDJI
Petroleum News

HAL KVISLE



FORREST CRANE

TONY PALMER

TransCanada Corp. is trying to temper recent reports that it wants the U.S. government to increase the federal loan guarantee covering financing of a natural gas pipeline in Alaska.

"TransCanada has not approached the government of the United States with regards to a revision of the loan guarantee. At this point, we don't know if we will do so," TransCanada Alaska President Tony Palmer told Petroleum News on Dec. 16.

If the Calgary-based company ultimately asks for an increase, Palmer said it would only ask to change an existing inflation clause, not the base amount of the actual guarantee.

As part of the Alaska Natural Gas Pipeline Act of 2004, Congress authorized guarantees to cover 80 percent of the capital costs of a gas pipeline up to $18 billion, but included a clause to adjust the guarantee for inflation by tying it to the Consumer Price Index.

"If the government of the United States intended the $18 billion to be equal to 80 percent, then

see **TRANSCANADA** *page 24*

NATURAL GAS

Alaska gas tax quandary

Gas rolled in with oil under present Alaska production tax would drop revenues

By KRISTEN NELSON
Petroleum News

1 2 SERIES

AL GRILLO

DAN DICKINSON

If North Slope natural gas production was rolled into Alaska's present production tax system on a barrel-of-oil-equivalent basis, state production tax revenues would drop.

Dan Dickinson, a former Tax Division director, told the Alaska Legislature's Budget and Audit Committee that numbers he ran in September, when Alaska North Slope crude oil was selling for around $80 a barrel and the Henry Hub spot price for natural gas was slightly more than $6 per thousand cubic feet (using current volumes of oil and estimates of gas sales) showed that adding in an estimated 4.2 billion cubic feet of gas sales a day would have reduced production tax revenues from $4.176 billion — if the state were getting production taxes only on oil — to $4.105 billion with combined revenues from oil and gas.

Dickinson said the issue is progressivity under the present system.

At the September price for ANS crude a 9.59 percent progressivity rate would have been added to the

see **QUANDARY** *page 23*

contents

Petroleum News | *A weekly oil & gas newspaper based in Anchorage, Alaska*

Alaska - Mackenzie Rig Report

*The Alaska - Mackenzie Rig Report as of December 18, 2008.
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 Alan Bailey

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status

Alaska Rig Status

North Slope - Onshore

Doyon Drilling			
Dreco 1250 UE	14 (SCR/TD)	Prudhoe Bay MPS-41	BP
Sky Top Brewster NE-12	15 (SCR/TD)	Kuparuk 3K-108	ConocoPhillips
Dreco 1000 UE	16 (SCR/TD)	Prudhoe Bay DS 4-45	BP
Dreco D2000 UEBD	19 (SCR/TD)	Alpine CD2-469	ConocoPhillips
OIME 2000	141 (SCR/TD)	Kuparuk annual maintenance	ConocoPhillips
TSM 7000	Arctic Fox #1	Stacked in Yard	Pioneer Natural Resources
	Arctic Wolf #2	Subcontracted for exploration	UltraStar Exploration
Nabors Alaska Drilling			
Trans-ocean rig	CDR-1 (CT)	Stacked, Prudhoe Bay	Available
Dreco 1000 UE	2-ES	Prudhoe Bay DS 01-34A	BP
Mid-Continental U36A	3-S	Milne Point MPG-02	BP
Oilwell 700 E	4-ES (SCR)	Prudhoe Bay R-11A	BP
Dreco 1000 UE	7-ES (SCR/TD)	Prudhoe Bay H-38	BP
Dreco 1000 UE	9-ES (SCR/TD)	Polaris W-218	BP
Oilwell 2000 Hercules	14-E (SCR)	Stacked	Available
Oilwell 2000 Hercules	16-E (SCR/TD)	Being fitted out for drilling this winter	Brooks Range Petroleum
Oilwell 2000	17-E (SCR/TD)	Stacked, Point McIntyre	Available
Emsco Electro-hoist -2	18-E (SCR)	Stacked, Deadhorse	Available
Emsco Electro-hoist Varco TDS3	22-E (SCR/TD)	Stacked, Milne Point	Available
Emsco Electro-hoist	28-E (SCR)	Stacked, Deadhorse	Available
Emsco Electro-hoist Canrig 1050E	27-E (SCR-TD)	Under modification	ExxonMobil
Academy AC electric Canrig	105-E (SCR-TD)	Stacked on ice pad at Chandler #1	Anadarko
Nordic Calista Services			
Superior 700 UE	1 (SCR/CTD)	Prudhoe Bay Drill Site DS15-15	BP
Superior 700 UE	2 (SCR/CTD)	Prudhoe Bay Well Drill Site MPB-23a	BP
Ideco 900	3 (SCR/TD)	Kuparuk Well ID-07	ConocoPhillips

North Slope - Offshore

Nabors Alaska Drilling			
OIME 1000	19-E (SCR)	Oooguruk ODSK-41	Pioneer Natural Resources
OIME 2000	245-E	Oliktok Point OP03-P05	ENI
Oilwell 2000	33-E	Stacked	BP

Cook Inlet Basin – Onshore

Aurora Well Service			
Franks 300 Srs. Explorer III	AWS 1	Lone Creek 4	Aurora Gas
Marathon Oil Co. (Inlet Drilling Alaska labor contractor)			
Taylor	Glacier 1	Maintenance	Marathon
Nabors Alaska Drilling			
Continental Emsco E3000	273	Stacked, Kenai	Available
Franks	26	Stacked	Available
IDECO 2100 E	429E (SCR)	Stacked, removed from Osprey platform	Available
Rigmaster 850	129	IRU 13-31	Chevron
Academy AC electric Heli-Rig	106-E (SCR/TD)	SRU 211-33	Chevron
Rowan Companies			
AC Electric	68AC (SCR/TD)	On site at Cosmopolitan	Pioneer Natural Resources

Cook Inlet Basin – Offshore

Chevron (Nabors Alaska Drilling labor contract)			
	428	M-32 Steelhead platform	Chevron
XTO Energy			
National 1320	A	Platform A no drilling or workovers at present	XTO
National 110	C (TD)	Idle	XTO
Kuukpik	5	Tyonek platform, A-16 completion	ConocoPhillips

Mackenzie Rig Status

Canadian Beaufort Sea

SDC Drilling Inc.			
SSDC CANMAR Island Rig #2	SDC	Set down at Roland Bay	Available

Mackenzie Delta-Onshore

AKITA Equtak			
Modified National 370	64 (TD)	Rigging up at Ellice Island, NT	MGM Energy Group

Central Mackenzie Valley

Akita/SAHTU			
Oilwell 500	51	Racked in Norman Wells, NT	BG Canada

JUDY PATRICK

Baker Hughes North America rotary rig counts*

	December 12	December 5	Year Ago
US	1,790	1,852	1,824
Canada	390	404	419
Gulf	62	60	59

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

GOVERNMENT

Alberta shifts ground with new report

In rolling out new energy strategy, government indicates royalty changes possible; promises to be 'solid environmental citizen'

By GARY PARK
For Petroleum News

Out of favor with its own petroleum industry and scorned by environmentalists on a global scale, the Alberta government may have had a Road-to-Damascus conversion.

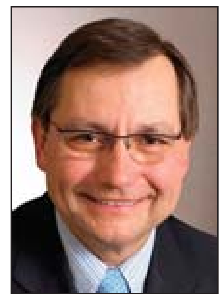
In releasing a long-promised provincial energy strategy, the administration of Premier Ed Stelmach has hinted that reviewing its controversial royalty structure is not out of the question.

At the same time, it is portraying itself as a caring steward of the planet by, among other steps, making a sweeping commitment to shrink the environmental footprint of its hydrocarbon industry, promote renewable energy and review greenhouse gas emission targets and carbon charges for large industrial facilities.

The 51-page report, entitled Launching Alberta's Energy Future, is described by Energy Minister Mel Knight as a comprehensive plan that supports the government's resolve to develop its energy resources — using the phrase of the times — "in an environmentally sustainable way."

He says Alberta — with estimated recoverable reserves of 315 billion barrels of crude bitumen, 124 billion barrels of crude oil and 223 trillion cubic feet of natural gas — wants to be recognized as a "responsible world-class energy supplier, an energy technology champion, a sophisticated energy consumer and a solid global environmental citizen."

Achieving that vision requires immediate action, Knight said.



Alberta Premier Ed Stelmach

Stelmach told a news conference that Alberta "must inspire the next generation of cleaner energy technology and more efficient energy use if we want to maintain our province's economic advantage."

Some hope of change

For an industry, still seething over the impact of royalty changes, Knight dangled a shred of hope that the new royalty framework is open to change.

"If we have lost our edge with respect to competition, I think it's time we did an in-depth analysis," he said.

"We understand that the industry at the moment, in Alberta and globally, is under a tremendous amount of pressure.

"Let's face it — the marginal barrel of oil (which prevails in Alberta) won't be produced at US$40 per barrel. Competition is what this is all about."

Stelmach echoed that thought, suggesting the energy industry is "truly at the crossroads, not only in Alberta, but around the world. Despite its many successes, the (Alberta industry) is clearly not immune from global economic pressures."

"Energy development remains the economic engine of this province and of this country," he said.

"The strategy acknowledges that hydrocarbons will continue to fuel both our economy and the global economy for many years to come. It also recognizes the urgent need to lessen the environmental impact of developing these resources."

Gord Currie, an oil and gas analyst at Wolverine Capital, said the strategy seems aimed at two groups: Environmental critics, both domestic and international, and Albertans who are looking for a greater share of the returns from their resource industry.

Scott Vail, vice president at Signature Global Advisors, said the government has made a "good start" in pinpointing the key questions and concerns.

Now it faces the tougher job of answering those challenges in an economically viable manner, he said.

EnCana, Petro-Canada cuts

Without expanding on how far the government might go in rethinking its royalty regime, Stelmach and Knight held their news conference about the same time that EnCana and Petro-Canada were driving home the damaging impact of higher royalties as they unveiled 2009 capital budgets that added to spending cuts they have already made this year.

EnCana said its Alberta capital program will be trimmed by 14 percent next year to US$2.3 billion, while Petro-Canada is lowering its overall budget to C$3.96 billion from C$6.16 billion, partly because high costs in Alberta have forced it to slow progress on its Fort Hills oil sands project.

Dave Collyer, president of the Canadian Association of Petroleum Producers, told reporters he was encouraged to hear Stelmach taking a second look at Alberta's competitiveness.

"That involves the fiscal structure; that involves the regulatory framework; it involves greenhouse gas policy and that's a key competitiveness indicator for us as a province and as an industry," he said.

While endorsing the general concept of the strategy, Collyer said Alberta must demonstrate a "sense of urgency" to ensure the province remains economic against other jurisdictions, both in conventional oil and gas production and development of the oil sands.

Against a backdrop of industry decisions to shelve new bitumen upgrader projects and more than C$40 billion of investment, Collyer also said Alberta will

see STRATEGY page 21

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GOVERNMENT

Obama names Salazar to head Interior

President-elect Barack Obama's pick for secretary of the Interior Department has been an opponent of drilling for oil in the Arctic National Wildlife Refuge.

Obama announced Dec. 17 he's picking Colorado senator Ken Salazar to lead the Interior Department.

The 58-year-old Salazar opposed drilling in ANWR on Alaska's North Slope and objected to the Bush administration's efforts to lease western lands for oil shale development.

It will be up to the Obama administration whether to go ahead with oil shale leasing.

ANWR development would need the approval of Congress.

Before being elected to the Senate in 2004, Salazar was Colorado's attorney general.

He also headed the state's Natural Resources Department from 1990 to 1994.

Salazar says he will do all he can to help reduce America's dependence on foreign oil.

—THE ASSOCIATED PRESS

● NATURAL GAS

YPC right-of-way renewal denied by DNR

Yukon Pacific loses 20-year-old conditional ROW for the trans-Alaska gas system for lack of progress required under the lease

By KRISTEN NELSON

Petroleum News

At one time a gas pipeline from the North Slope to a liquefaction plant at Valdez seemed the answer to commercializing Alaska's natural gas.

Yukon Pacific Corp., an early LNG project proponent, obtained a number of permits for the project including, in 1988, a conditional right of way for that line from the Alaska Department of Natural Resources. The right of way was renewed in 1998, but this year DNR Commissioner Tom Irwin denied a renewal request, citing lack of progress on project plans or programs required in the conditional lease.


TOM IRWIN

The original conditional right-of-way lease allowed the commissioner to renew the lease as long as the lessee was in full compliance with the provisions of the conditional lease and state and federal laws.

When the lease was renewed in 1998, however, the renewal clause was amended to require that the lessee demonstrate that "substantial progress has been made" toward a determination that the lessee "is fit, willing and able to perform the transportation or other acts proposed in accordance" with state law.

Fit, willing and able

The Alaska Right-of-Way Leasing Act requires the commissioner to determine "whether an applicant is fit, willing, and able to perform the transportation or other acts proposed in a manner that will be required by the present or future public interest," Irwin said in his decision.

A conditional right of way may be granted under conditions "that will ensure that the applicant will, within a prescribed period of time not exceeding 10 years, establish that the applicant is fit, willing, and able, under (a) of this section, to perform the transportation or other acts that will be required by the present or future public interest."

Irwin said YPC addressed "some, but not all of the applicable provisions of the conditional lease" in the renewal request.

The commissioner found in his decision that the proposed pipeline route "is not delineated sufficiently to determine if the project will unreasonably conflict with existing uses of the land involving a superior public interest."

YPC had not requested authorizations to proceed — other than two work permits which have now expired — and "has not demonstrated substantial progress toward a determination that YPC is fit, willing and able to perform the transportation or other acts" provided for in the conditional lease, he said.

Ability to protect property

Consideration of the applicant's "technical capability to protect state and private property interest" is required under the Right-of-Way Leasing Act. Irwin said YPC's 2008 renewal request included a number of items under the discussion of progress toward a fit, willing and able determination.

YPC said several items had not been submitted to the state because of confidentiality considerations, including plans for a gas conditioning plant, but, Irwin said, "YPC does not indicate whether or not they will construct a gas conditioning facility and does not indicate the means by which YPC will obtain gas for transport."

Both a determination of whether a gas conditioning facility will be constructed and determination of how gas will be obtained are requirements of the conditional lease.

On the pipeline route, Irwin said YPC's request indicated the route description had been updated, but he said the conditional lease required YPC to submit technical information on the project including a project development schedule. "No record was found in the case file that YPC submitted a project development schedule during the period of time since the last renewal of the conditional lease," the commissioner said.

YPC suspended a review of a pipeline route revision in 2003 "and thus severely hampered" DNR's ability to determine if YPC had the capability to protect state and private property interests along the route.

YPC also had not submitted project performance standards required in the conditional lease, the commissioner said. And while the renewal request said YPC has designed "a comprehensive construction plan" for the pipeline, "... YPC does not state that the construction plan was submitted to DNR for review and approval."

AGPA option has expired

YPC told DNR it executed an exclusive option in 2004 with the Alaska Gasline Port Authority and that the option expired in 2008.

The commissioner said the conditional lease provided that YPC would not "transfer, assign, pledge, or dispose of in any manner, directly or indirectly, or by transfer of control of YPC's interest" without a written finding by the commissioner. He said YPC said in its 2008 renewal that there had been no change of ownership or control since 1998.

YPC did not appear to have obtained authorization from the commissioner to execute the option with the port authority. "It is unclear whether YPC's execution of an exclusive option to AGPA would constitute an indirect pledge to transfer control of YPC's interest," Irwin said. "However, as YPC indicated that the option with AGPA has expired, it will not be further evaluated in this decision."

The conditional lease requires evidence of financial commitment to design and construct the pipeline, including "letters of intent for gas sales, letters of intent for gas purchase and written preliminary commitments for construction financing."

—DNR decision denying right-of-way license renewal

Full lease requirements

To convert a conditional to an unconditional lease, the applicant must provide documentation showing it "is technically and financially capable of constructing and operating the gas pipeline," the commissioner said. "YPC has not provided evidence of technical and financial capability to protect the state and private property interests" as described in the conditional lease.

The conditional lease requires evidence of financial commitment to design and construct the pipeline, including "letters of intent for gas sales, letters of intent for gas purchase and written preliminary commitments for construction financing."

The commissioner said that since the 1998 renewal YPC has not complied with the requirements of the conditional lease and the information provided by YPC is not enough to allow for such a determination.

"As the status of this determination has not changed substantially since 1998 renewal of the conditional lease, YPC has not demonstrated substantial progress" toward a determination that it is "fit, willing and able to perform the transportation or other acts" listed in the conditional lease.

YPC downsized in 2001

Yukon Pacific Corp. was founded in the 1980s after the original proposal to take Alaska North Slope natural gas to market

see YPC RENEWAL page 6

LAND & LEASING

Season of good cheer in part of Canada

B.C., Saskatchewan find more than lumps of coal under Christmas tree; feast on year of land sales records, brace for '09 downturn

By GARY PARK

For Petroleum News

It is now official beyond any doubt. Alberta has been toppled from its seemingly untouchable position as Canada's leading land sales province.

The formalities were concluded Dec. 12, when British Columbia posted a record C$2.66 billion from 2008 auctions, easily eclipsing its previous high-water mark of C$1.2 billion in 2007.

Just to reinforce the message that Alberta is no longer the unchallenged hydrocarbon region in Canada, Saskatchewan reported sales for the year of C$1.12 billion, drowning the previous calendar year record of C$250 million in 2007.

British Columbia Energy Minister Richard Neufeld

Alberta, with only one sale left, has pocketed C$1.19 billion from its bidding rounds, trailing last year's comparable total by C$170 million. But its 12-month record of C$3.46 billion in 2006 is a distant memory, as the industry drives home its dissatisfaction with the Alberta royalty structure and reacts to the province's high-cost environment and shrinking pool sizes.

For the two provinces flanking Alberta, the year's results are vindication of their royalty regimes, although both have cautioned that they don't expect to see repeat performances in 2009.

Saskatchewan Energy Minister Bill Boyd said it is "unlikely" his government will have back-to-back billion dollar years.

"Clearly, when you have a downturn in the oil price, it's going to have an affect in the future," he said. "We're still optimistic, however."

Many licenses for two years

Even if land sales dip in 2009, much of the land acquired by oil and gas explorers in Saskatchewan carries only two-year licenses.

Ed Dancsok, director of the province's geology and petroleum lands branch, said Saskatchewan has the good fortune to share the Bakken formation, which extends across the border from North Dakota and is rated as the hottest oil play in North America.

"What you'll start seeing now is that companies, based on the land they've already purchased, will be looking to get a rate of return on the healthy prices they have paid," Boyd said. "That means increasing exploration and production budgets."

He cited recent announcements by Crescent Point Energy Trust and TriStar Oil & Gas, which have earmarked the majority of their 2009 spending programs of C$200 million-$300 million for Saskatchewan.

The Petroleum Services Association of Canada has forecast Saskatchewan will see a 9 percent rise in drilling next year to 4,725 wells.

Ed Dancsok, director of the province's geology and petroleum lands branch, said Saskatchewan has the good fortune to share the Bakken formation, which extends across the border from North Dakota and is rated as the hottest oil play in North America.

"There are not many places where the rate of return is as good as the Bakken," he said, noting oil companies are paying an average C$488 per hectare in Saskatchewan compared with C$164 in Alberta.

Neufeld: B.C. 'competitive'

British Columbia Energy Minister Richard Neufeld said this year's land sale results show B.C. will play a major role in meeting North American natural gas demand.

He told The Energy Council, representing international oil and gas producers, that B.C. is a "competitive jurisdiction in North America for oil and gas investment."

He noted that world demand for gas is forecast to rise 51 percent by 2030, with gas emerging as a fuel for transportation, industry and heating and as a transitional fuel for electricity generation in lieu of coal-fired power.

"North American demand is projected to rise over the next 20 years and British Columbia has an opportunity to provide more natural gas to" the United States, Neufeld said.

While overall Canadian production is off 4 percent this year and expected to keep dropping as the Western Canada Sedimentary basin matures, B.C. is a "bit of a paradox in this supply status question," he said.

Pacific Trail deadline

"B.C. may have an opportunity to become a North American leader in producing and exporting natural gas," he said, referring to a possible breakthrough project by a partnership of Pacific Northern Gas and Kitimat LNG to build a C$4.2 billion project to export LNG to Asian markets.

"B.C. may have an opportunity to become a North American leader in producing and exporting natural gas."

—B.C. Energy Minister Richard Neufeld

The Pacific Trail project has set a Dec. 22 deadline for gas shippers and LNG buyers to indicate whether they are prepared to support the scheme and take advantage of strengthening LNG prices and the rapidly developing unconventional gas plays in northeastern B.C.

Neufeld said use of deep-drilling methods used to open up the Barnett field in Texas could be applied to B.C's Horn River and Montney plays.

"Production in the future could double or triple according to some estimates," he said. "This puts B.C. in the unique position of being able to increase sales to Alberta, Eastern Canada, the U.S. and other export markets," he said, noting that the extraction of unconventional gas in B.C. has seen investment climb from about C$1 billion a year through the 1990s to C$5 billion a year since 2001. ●

continued from page 5

YPC RENEWAL

through Canada collapsed due to rising costs and dropping Lower 48 natural gas prices.

When the conditional right-of-way lease was renewed in 1998, YPC, by then a subsidiary of CSX Corp., held permits for an all-Alaska LNG project bringing North Slope natural gas to Valdez and liquefying it there for shipment to the Far East, along with authorizations from the President of the United States and the U.S. Department of Energy to market Alaska-produced LNG to Asian buyers.

Jeff Lowenfels, then president of YPC, told Petroleum News in 1998 that the state right of way was the only one of the company's permits that needed to be renewed.

In December 1998 YPC was also a member of the Alaska North Slope LNG Project, a consortium of companies formed earlier that year by ARCO Alaska to work on an LNG project to deliver Alaska North Slope gas as LNG to markets in the Far East.

In the summer of 1999, YPC withdrew from the ANS LNG Project to focus on the Valdez route for which it had permits. (The producer-led LNG study group wound up its work in the fall of 2001, concluding an LNG project was not commercial.) Later in 1999 YPC discussed a management role in the Alaska Gasline Port Authority, to be voted on that fall by Valdez, the Fairbanks North Star Borough and the North Slope Borough. AGPA later took an option on the YPC permits.

In the fall of 2001 YPC was downsized, with CEO Jeff Lowenfels going to part-time consulting status and then leaving the project entirely. The following year the company downsized the project, going from a 36-inch line to a 30-inch line, and said it would look to either the natural gas owners, pipeline companies or the state development authority to build the project. ●

GOVERNMENT

Begich says get projects ‘job ready’

Returning from Washington, senator-elect says bid ready projects more likely to be funded in any future infrastructure program

By **ERIC LIDJI**

Petroleum News

Alaska could reap the most benefits from a major federal stimulus package expected in the coming year by readying a slate of projects, according to Senator-elect Mark Begich.

“Many in Congress are saying that they have to be job ready,” Begich said on Dec. 11.

MARK BEGICH

Begich, who spoke to reporters after his first tour of Washington, D.C., since winning the election, said the debate in Congress currently revolves around how best to fund those projects, whether to use a formula for the states, fund actual projects or mix approaches.

But Begich said he expects infrastructure projects to be prioritized based on their ability to create jobs, have long-term impacts and preferably include an energy component.

That criteria could bode well for a slate of transportation projects in Alaska that need to be completed before construction begins on a natural gas pipeline from the North Slope.

> *“There probably will be a bias, but my job is to equalize it.”*
>
> **—Senator-elect Mark Begich**

“It is imperative that we have the necessary infrastructure in place to bring in and stage all the materials that will be used during the construction,” Drue Pearce, federal coordinator for Alaska natural gas transportation projects said in late November.

Those projects include upgrades to almost every major highway in Alaska, including the 416-mile Dalton Highway, the only land route to the North Slope, as well as the Glenn and Parks highways, two of the busiest roads for commuters and industry in the state.

In the proposed budget for fiscal year 2010 unveiled on Dec. 15, the Palin administration included funding for some of those projects, like work on the Richardson and Haines highways, but not for others, like expensive work needed for the Dalton-Elliott corridor.

In early December, President-elect Barack Obama announced plans for the “single largest new investment in our national infrastructure since the creation of the federal highway system in the 1950s” as a way to spur job growth and stimulate the sinking economy.

“If a state doesn’t act quickly to invest in roads and bridges in their communities, they’ll lose the money,” Obama said in his weekly radio address on Dec. 6.

‘Ready to go’ projects

Alaska has only four “ready to go” transportation projects, according to a survey released Dec. 5 by the American Association of State Highway and Transportation Officials.

Only Washington, D.C., had fewer “ready to go” projects, defined in the survey as projects that “could be under contract within 180 days … if the funding were made available.”

The four Alaska projects would be worth around $139.3 million, the survey estimated.

Asked if he thought Congress might oppose funding projects in Alaska, a small state with large savings, Begich said, “There probably will be a bias, but my job is to equalize it.” ●

E&P

Tundra remains closed for winter off-road travel

The Department of Natural Resources said Dec. 12 that it has completed an assessment of snow conditions and soil temperatures on the North Slope and all areas remain closed to tundra travel.

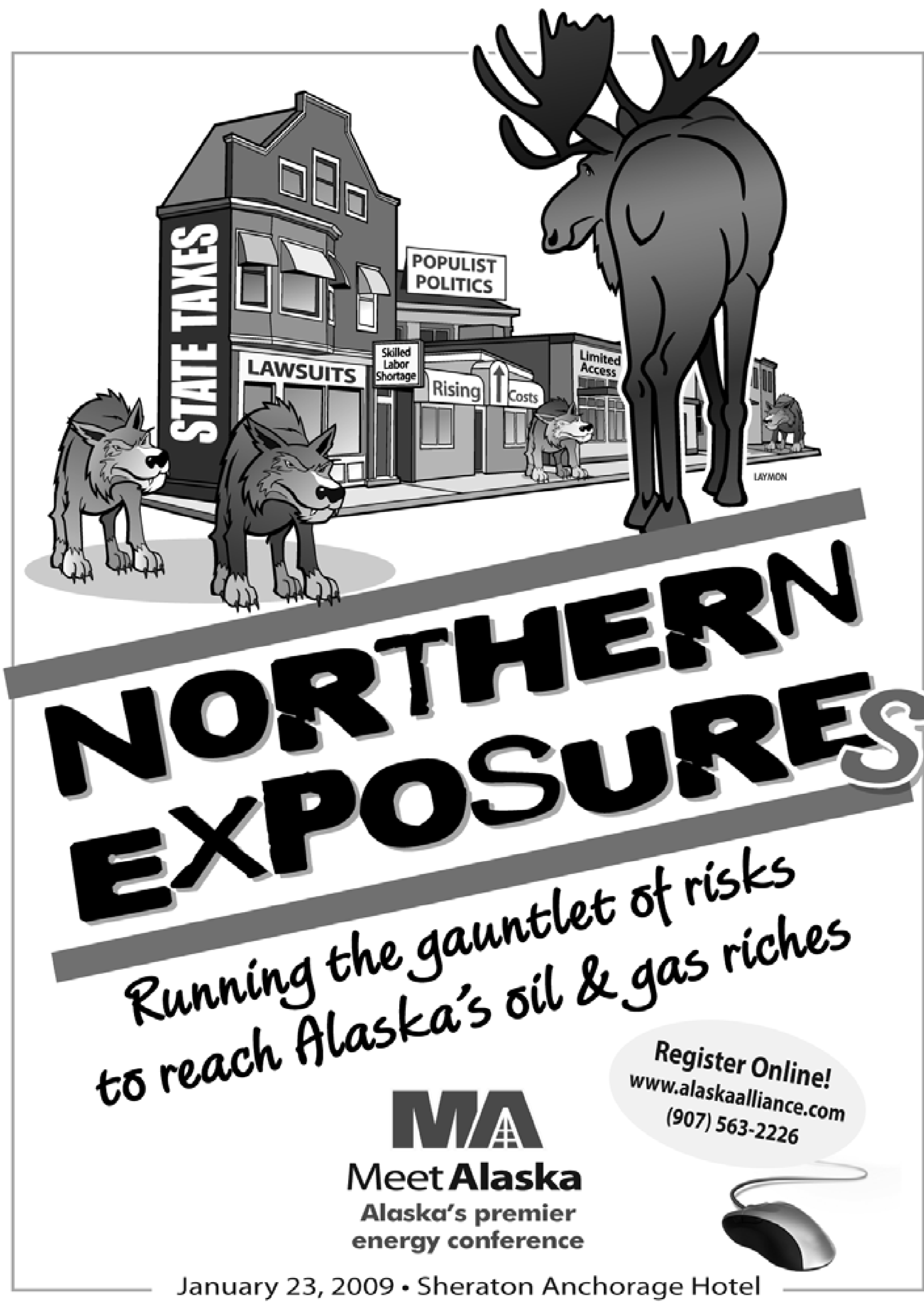
Soil temperature has moved below minus 5 degrees Celsius at 11 of the 19 monitoring stations. Snow is very deep this year, the department said, with snow depths above that required for tundra opening at all but one station.

The target of the foothills tundra opening areas is 9 inches of snow and minus 5 degrees C soil temperature at a depth of 30 centimeters. The target for coastal areas is 6 inches of snow and minus 5 degrees C soil temperature at 30 centimeters.

The department said pre-packing ice road routes using summer-approved vehicles has been approved for several projects, allowing soil temperatures to drop to the extent that some projects have been approved to move forward with ice road construction.

Pre-packing must be approved by the department.

—PETROLEUM NEWS



● EXPLORATION & PRODUCTION

Alberta oil sands frenzy fizzling

Sector could be headed for prolonged slowdown, C$100 billion scrapped and delayed; Merrill Lynch says 800,000 bpd could be shut-in

By GARY PARK

For Petroleum News

Total made its contribution to the collapse of oil sands mine and upgrader projects in Alberta on Dec. 12 and caused scarcely a murmur in the process.

The Canadian unit of the French oil giant withdrew its regulatory application for the Northern Lights mine, originally planned to produce 114,500 barrels per day of bitumen, just four months after wrapping up its takeover of Synenco Energy to take a 60 percent controlling interest in the project. SinoCanada Petroleum, a subsidiary of China's Sinopec, holds the remaining 40 percent.

However, Total said it will push ahead with its Joslyn North mine, scheduled to produce 100,000 bpd by 2013. Joslyn South is in the project definition phase, targeting another 100,000 bpd four years after Joslyn North is in operation.

A spokeswoman for Total said Northern Lights is being integrated into the company's overall oil sands strategy, but how that will take place is under review.

"We'll reinstate (Northern Lights) at an appropriate time," she said.

Change may be fundamental

This development serves mostly to endorse a school of thought that the oil sands are not just taking a time out during the economic crisis, but may be undergoing a fundamental change that will do what a lot of politicians, community leaders and environmentalists want and drastically slow the frenzy of development that has stretched professional services, labor and materials to the limit.

CIBC World Markets estimates project cancellations and delays affect C$100 billion worth of investment, wiping out 800,000 bpd of production, about half what was projected over the next five years.

But CIBC chief economist Jeff Rubin forecasts global output will "flatten materially, falling as early as 2010 as new capacity additions fail to keep pace with approximately 4 million bps of global depletion."

He said supply strains will start emerging beyond mid-2009 … setting the stage for a return to US$100-per-barrel oil within 12 months.

US$38 oil needed

A Merrill Lynch report said oil sands projects need US$38 oil to break even, with many existing projects close to losing money at today's oil prices and limiting the ability of developers to fund expansions.

If oil dips below that level, the firm says almost 800,000 bpd — about 30 percent of Canada's total output — could be shut-in and another 800,000 bpd would be at risk if oil slipped under US$30.

"With demand vanishing across all key oil consuming regions, a strong rebound in prices in the first half of 2009 is unlikely," Merrill Lynch analysts said.

The brokerage firm said in-situ oil sands projects need an economic threshold of US$38 and integrated projects (those than mine and upgrade) need US$30, while conventional projects have a break-even price of US$22.

A Merrill Lynch report said oil sands projects need US$38 oil to break even, with many existing projects close to losing money at today's oil prices and limiting the ability of developers to fund expansions.

A consensus among industry observers suggests projects are not likely to be revived even if oil prices return to US$90.

Should the current downturn help reduce costs that is not the only hurdle to be overcome.

Among the unknowns are what environmental measures the Obama administration will take that could undermine the oil sands sector and whether the Canadian government will follow that lead.

Alberta fallout severe

But the fallout is already severe in Alberta, with the Construction Owners Association of Alberta, an umbrella organization for Alberta's largest construction companies, estimating that the workforce needs for 2010 — previously seen as a peak year — will be slashed to 22,000 from 44,000.

"There are a lot of layoffs happening in the shops and downsizing is taking place in the field," said Lorne Oswald, president of Dacro Industries, a high-pressure vessel manufacturer.

"The massive importing of labor into Alberta has ended and a lot of those people are looking at going home again," he told the Edmonton Journal, adding Dacro has had a number of contracts cancelled.

Oswald said he has never seen anything to match the current circumstances in his 35 years in the oil-related business.

"We've gone through some tough times in the oil patch, but this seems to be more widespread. The problem is complete uncertainty."

He said Dacro has specialized in working for oil sands developers, where multiyear project deferrals indicate that no one appears to know what lies ahead.

Stephen Hutchison, general manager of Altex Industries, which produces heat exchangers, said his company has orders stretching through summer.

"But you never know when somebody is going to phone you and put their project on hold," he said. "Customers can cancel at any time and buying has already slowed down."

Crisis could halt oil sands

Bob Dunbar, president of consulting firm Strategy West, said a prolonged financial crisis could see the oil sands come to a halt once current work is completed.

He expects oil sands output to increase to 2 million bpd from the current 1.3 million bpd by 2010-11, but the goal of 3.5 million bpd by 2015 no longer seems attainable.

Even if there is a financial recovery in the near term, growth will only resume at a moderate pace because of the years needed to plan and build projects, obtain regulatory approvals and assemble the workforces.

Peter Tertzakian, chief energy economist at ARC Financial, said growth will now be influenced by lessons learned during the financial crash and the prospect of wild swings in oil prices.

He also said environmentalists have damaged the oil sands, which will cause developers to have second thoughts about whether and to what extent they want to be in the business.

Controversial report issued

Just this month, the Alberta government has been scrambling to downplay a report by Environmental Defense, a Toronto-based conservation advocacy group, which claimed ponds storing wastewater left over from the processing of bitumen are leaking about 11 million liters per day of contaminated water into Alberta's ground water and natural ecosystems.

"Virtually everyone close to the tar sands industry knows that all tar sands tailings ponds leak — even the new ones — and that while steps are taken to recapture the leakage, a significant portion of the contaminated water still escapes into the environment," the report said.

The study is viewed as the first comprehensive examination of water pollution from the mines in Alberta and was based on figures from environmental assessment applications submitted by oil sands companies.

The report said "tar sands tailings water is widely acknowledged to be harmful to human health and the environment," causing serious reproductive impacts among fish, high mortality rates among birds and delayed germination among plants.

A scientist from the Alberta government's Environment Department said the findings are misleading people by suggesting that the waste from the tailings ponds are contaminating natural ecosystems.

He said most of the wastes find their way into deep aquifers that are already naturally contaminated by the geology of the oil sands.

"They make some statements that are patently false," said the scientist, Preston McEachern, who said the government is spending millions of dollars to research the environmental impact of the tailings ponds and is confident it can prevent any serious contamination of groundwater or ecosystems.

"Occasionally problems do occur … but we're finding now that our systems are set up well enough that we detect them right away before they will ever become a risk to the environment," he said.

Regardless of those assurances, the Athabasca Chipewyan First Nation, downstream of the oil sands, is taking the province to court, alleging it failed to consult with the community before allowing oil sands development on the nation's traditional territory.

Chief Allan Adam said the Chipewyan people are worried that wildlife could disappear and water supplies could be in danger, demanding to be "at the table at the start of any kind of process involving development." ●

● NATURAL GAS

FNG asks to stay course on deregulation

Company president says regulation would only increase rates, prevent FNG from attracting needed capital investment, recouping losses

By ERIC LIDJI
Petroleum News

Regulating Fairbanks Natural Gas would lead to increased rates and would prevent the company from attracting outside investment, according to a top company executive.

In testimony filed with state regulators on Dec. 12, Fairbanks Natural Gas President Dan Britton said his company took losses for many years in an attempt to provide cheaper fuel to its customers. But that business model, he said, depends on the company recouping its losses in the future by easily adjusting its rates without the cost of regulatory approval.

Britton's testimony came as part of an on-going Regulatory Commission of Alaska investigation into whether Fairbanks Natural Gas should be economically regulated.

Fairbanks Natural Gas is the only natural gas utility in Fairbanks, an energy market dominated by several unregulated heating oil companies that compete for prices on a weekly basis. To compete in that market, state regulators economically deregulated Fairbanks Natural Gas in 2003, letting the company change rates without permission.

The current investigation is the second concerning Fairbanks Natural Gas' rates in recent years. Both cases began in part based on requests from Rep. Jay Ramras, R-Fairbanks.

The initial investigation began after Fairbanks Natural Gas lost a gas contract in the fall of 2006, coming within days of running out of gas. The RCA placed watchdog measures on Fairbanks Natural Gas, but ultimately decided not to reinstate economic regulation.

The current case is based on a May 2008 request from Ramras and 13 state lawmakers from the Southcentral region. The lawmakers felt state regulators should investigate the regulatory status of Fairbanks Natural Gas after the company posted a profit in 2007.

Those lawmakers chose not to be involved in the case, instead deferring to the Attorney General's office. In testimony filed in late October, a pair of witnesses for the Attorney General recommended against reinstating economic regulation for Fairbanks Natural Gas, but proposed installing rate caps or market thresholds to temper rates in the future.

On the Web

See previous Petroleum News coverage:

"Another look at regulation for FNG," in June 15, 2008, issue at www.petroleumnews.com/pnads/153683274.shtml

"AG witnesses sour on re-regulating FNG," in Nov. 9, 2008, issue at www.petroleumnews.com/pnads/251001265.shtml

Britton argued against those ideas, saying that if Fairbanks Natural Gas is regulated as soon as it becomes profitable, the company could not recover losses incurred until now.

He said the company needs constancy in order to attract new capital investment.

Are customers held captive?

A major concern of regulators and the Attorney General's office is whether Fairbanks Natural Gas customers are "captive," in other words, whether the technical costs of switching between oil and gas may keep customers locked in to one fuel or the other.

While Britton acknowledged that some residential customers might have difficulty switching, he argued that all Fairbanks gas customers originally paid to switch from oil.

He also said Fairbanks Natural Gas has "approximately 1 percent of the overall Fairbanks residential market" and can't exercise market power without scaring off new customers.

The gas-to-oil price ratio

Because no gas pipelines currently connect Fairbanks and Anchorage, Fairbanks Natural Gas buys and liquefies Cook Inlet gas before trucking it north to Fairbanks.

This unique arrangement is costly. The company loses around 20 percent of its gas in liquefaction, and transportation expenses change constantly with the price of diesel. Still, Fairbanks Natural Gas managed to underprice heating oil in Fairbanks for many years, Britton said, saving customers millions of dollars while taking losses year after year.

The contractual problems of 2006, though, prompted a series of rate increases. By June 2007, natural gas prices in Fairbanks topped prices for heating oil for the first time.

With oil prices fluctuating wildly over the past year, natural gas was the cheaper fuel in Fairbanks over the summer, but is now around 45 percent more expensive than oil.

Britton claims those increases came from unexpected costs, not from deregulation.

Because Fairbanks Natural Gas took losses in the past to remain competitive, Britton believes rates would increase under regulation, which sets a fixed rate of return. The comment echoes a point made by one of the Attorney General's witnesses in October.

Fairbanks Natural Gas is currently working to switch its supply of gas from Cook Inlet to the North Slope, a move that would require building a major liquefied natural gas plant.

In a small setback, RCA recently denied Fairbanks Natural Gas' request for a refund as part of a recent settlement agreement between Enstar Natural Gas and Aurora Gas. ●

Contact Eric Lidji at 907-522-9469 or elidji@petroleumnews.com

EXPLORATION & PRODUCTION

Anadarko applies to drill at Wolf Creek

Anadarko Petroleum has applied for a permit to drill a gas exploration well in the National Petroleum Reserve-Alaska, according to filings with federal authorities.

The Bureau of Land Management posted notice on Dec. 16 of the application from Anadarko to drill the Wolf Creek No. 4 exploration well, about 30 miles west of Umiat.

In September, Anadarko staked three wells at the Wolf Creek Prospect, all situated on federal lease AA-86604 in the northeast planning area of the reserve.

Anadarko previously told Petroleum News it plans to use the Doyon Arctic Fox rig to drill Wolf Creek No. 4 to a depth of around 4,000 feet to test the Nanushuk formation.

Anadarko is planning to use two rigs to drill three exploration wells this winter. The company is partnering on the exploration program with Petro-Canada and BG.

Currently travel is restricted across the North Slope pending lower temperatures.

—ERIC LIDJI

NATURAL GAS

Sempra's Mexican LNG terminal: one cargo

Terminal has cash flow, although just one ship since Baja California facility opened in May; Tangguh will send cargoes in 2009

By ALLEN BAKER

For Petroleum News

COURTESY SEMPRA

Sempra's LNG port near Ensenada, Mexico.

Darcel L. Hulse is a man supervising a new billion-dollar LNG port, with a second one about to be completed. Only a single ship has called at his existing port near Ensenada, Mexico, since it began commercial operation in May.

But Hulse, Sempra LNG's president and CEO, has rent coming in from Shell, a contract for cargoes from Indonesia starting in mid-2009, and optimism about a new reality in the world LNG trade.

1 2 SERIES

He thinks that new reality will bring his ports some real business, even though U.S. gas prices are well below what Asian markets are paying.

Not just price

"The issue really isn't just price," Hulse said in a Dec. 2 interview with Petroleum News. "It's supply versus demand globally. If we're in an oversupply situation, some of those cargoes will flow to the United States."

And he thinks that situation is coming just months from now:

"We'll start seeing it (excess supply) next year or in 2010."

With broad Asian experience as president of Unocal Asia-Pacific Ventures before coming to Sempra, Hulse is a man to be heard — even if his predictions fly in the face of conventional wisdom about the LNG market.

Conventional wisdom, from analysts in and out of government, predicts tight supplies in the next few years, and major shortages of LNG in the world market a few years hence.

"They ignore a recession and declining demand, with very robust supplies coming into the market," says Hulse. "Forecasts are never exactly accurate."

Broader economics

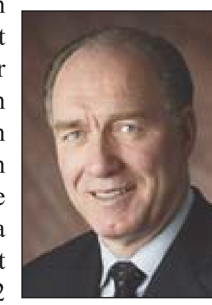
Besides, he says, LNG projects most often have an oil or condensate component as well as the gas, so it pays to produce even if gas prices are relatively low. "About 80 percent of the gas in the world and the LNG traded in Asia has got some oil formula in it. It's artificially tied to a scarce commodity."

Much of the world's LNG production has been tied up in long-term contracts of 20 or 25 years, particularly in Asia. Big utility customers in Japan, Korea and Taiwan have been willing to pay a premium to ensure long-term supplies.

But Hulse is hoping that the emergence of Qatar as an LNG superpower will open things up and LNG will turn into a commodity with an active, competitive spot market.

Qatar's flexibility

Qatar is positioned to send cargoes just about anywhere in the world, and the nation sits on one of the largest gas fields ever found. The nation has new modern ships and can reach either shore of North America for a transport cost of about $2 per thousand cubic feet of gas equivalent, he figures.



DARCEL HULSE

"Qatar has a unique position — I think they're viewing the world totally differently," he says. "In a commodity market, the greatest virtue I can have is optionality to capture the peaks in all the markets. Qatar has large supplies and equal costs to either basin (Atlantic or Pacific). They have great flexibility as long as they don't contract it all up."

LNG as commodity

Hulse thinks that LNG will become a global com-

see LNG page 16

FINANCE & ECONOMY

EIA forecast for slowed energy growth

By KRISTEN NELSON
Petroleum News

U.S. oil consumption will be flat to 2030, with slower growth in energy use and carbon dioxide emissions and reduced import dependence, the U.S. Energy Information Administration said Dec. 17 in its "Annual Energy Outlook 2009."

The EIA said that for the first time in more than 20 years, its new Annual Energy Outlook reference case "projects virtually no growth in U.S. oil consumption, reflecting the combined effect of recently enacted CAFÉ standards, requirements for increased use of renewable fuels and an assumed rebound in oil prices as the world economy recovers."

Liquid fuel use in the U.S. is projected to grow by only 1 million barrels per day between 2007 and 2030, the agency said. And with more domestically produced biofuels "and rising domestic oil production spurred by higher prices," net import of liquid fuels, including biofuels, is expected to decline from 58 percent in 2007 to less than 40 percent in 2025 and to increase to only 41 percent by 2030.

EIA, is, however, projecting more U.S. production and use of natural gas, based on increasing availability and higher demand for electric power generation.

Natural gas use to rise

EIA, is, however, projecting more U.S. production and use of natural gas, based on increasing availability and higher demand for electric power generation. The agency said growing production from unconventional onshore sources, the outer continental shelf and Alaska will result in a decline in net imports of natural gas, from 16 percent of gas used to less than 3 percent in 2030. The EIA showed Alaska gas becoming available in the Lower 48 before 2020.

Domestic production of natural gas is expected to reach 23.7 trillion cubic feet by 2030 and while "exploration and production costs rise over time, higher natural gas prices support the projected level of production," the agency said. Onshore unconventional natural gas production — including shale gas — is expected to increase from 9.2 tcf in 2007 to 13.2 tcf in 2030.

Total primary energy use and energy-related carbon dioxide emissions are expected to slow due to efficiency policies and higher energy prices. EIA said it expects U.S. energy use to grow from 101.9 quadrillion Btu in 2007 to 113.3 quadrillion Btu in 2030. That growth rate, combined with increased use of renewables and a reduction in new coal-fired conventional power plants, slows growth in energy-related greenhouse gas emissions.

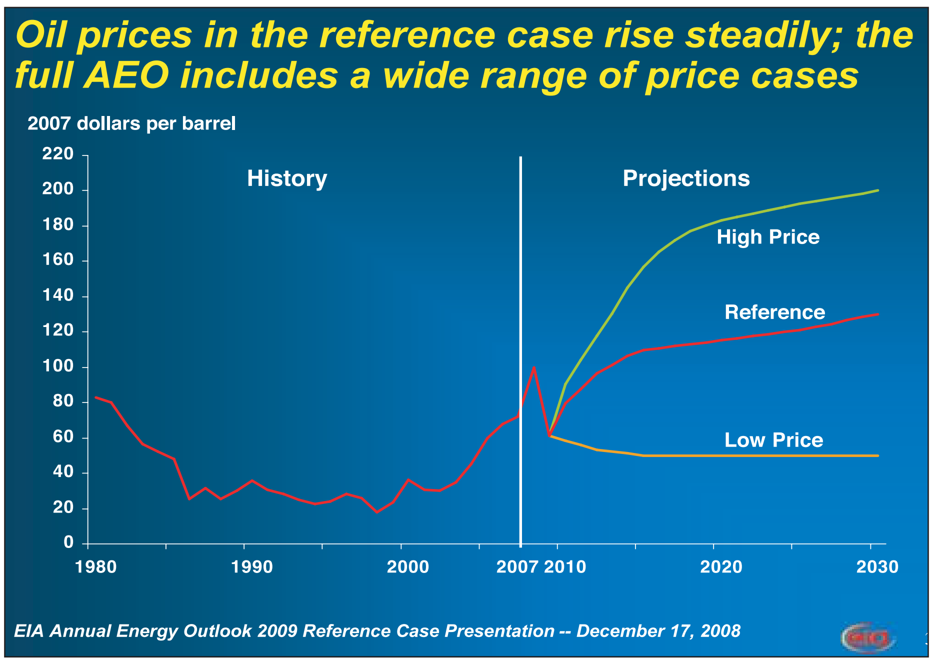
Energy-related CO2 emissions are expected to grow at a rate of 0.3 percent per year from 2007 to 2030 in the 2009 reference case, reaching 6,410 million metric tons in 2030, compared with a projection of 6,851 metric tons by 2030 in the 2008 reference case.

Oil price projected to be higher

Higher world oil prices in the 2009 reference case reflect "tighter constraints on access to low-cost oil supplies" and a continuing assumption of long-term demand growth in non-Organization for Economic Cooperation and Development countries, the EIA said.

"In 2007 dollars, the world crude oil price, averaging near $60 in 2009, rises as the global economy rebounds and global demand once again grows more rapidly than non-OPEC liquids supply," and reaches $130 per barrel in 2007 dollars ($189 per barrel in nominal dollars) in 2030.

see FORECAST page 13



OPEC cuts 2.2M barrels a day

OPEC said Dec. 17 it is cutting 2.2 million barrels a day from its output to stem crude prices that have plummeted more than 70 percent from summer highs approaching $150.

An OPEC statement says the group is taking 4.2 million barrels a day off the market, compared with September levels. Members under production quotas among the 13-nation organization were officially producing a daily 29.045 million barrels in September.

The 4.2 million figure thus includes more than 500,000 barrels of overproduction that OPEC said in September it would eliminate, and a

see OPEC page 13

LAND & LEASING

Conoco expands Alpine, Nanuq Kuparuk

State approves participating area expansions, adding some 9,200 acres to Alpine PA, some 4,400 acres to Nanuq Kuparuk PA

By KRISTEN NELSON
Petroleum News


JUDY PATRICK

Alpine, the main producing field in the Colville River unit, was expanded by some 9,200 acres — from 28,695 acres to 37,908 acres.

The Alaska Division of Oil and Gas has approved expansions of the Alpine and Nanuq Kuparuk participating areas in the Colville River unit on the western side of the North Slope. Participating areas are the portions of a unit from which oil and gas are produced. They are expanded or contracted as the operator becomes more knowledgeable about areas within the unit capable of producing hydrocarbons in paying quantities.

Alpine, the main producing field in the Colville River unit, was expanded by some 9,200 acres — from 28,695 acres to 37,908 acres. Nanuq Kuparuk, one of two participating areas in the Nanuq satellite south of Alpine, was expanded some 4,400 acres — from some 8,157 acres to some 12,574 acres.

The Alpine PA expansion areas are along the north and northeastern edge of the PA and along the entire western and southern boundaries.

Most of Alpine drilling done

ConocoPhillips Alaska, the operator and majority working interest owner at the Colville River unit, told the Department of Natural Resources and Arctic Slope Regional Corp. — the unit is on both state and ASRC acreage — that since "drilling of the majority of the reservoir accessible from existing drill sites is complete, Alpine production rate is expected to continue to decline throughout the 2008-2012 time period."

Production from Alpine began in late 2000. Average monthly production from the Alpine field alone peaked in November 2005 at a monthly average of some 130,600 bpd. Colville River unit production peaked in May 2007 at 138,984 barrels per day and production from the unit has recently been averaging less than 120,000 bpd.

According to October Alaska Oil and Gas Conservation Commission production figures, the latest available from the commission, which provides production figures by pool, less than 60 percent of Colville River unit production is now from the Alpine field; the remainder is from Alpine satellites. Nanuq accounts for 22 percent, Fiord for 18 percent and the newest satellite, Qannik, for 1 percent. All Colville River unit production is

see EXPANSION page 13

CRU Nanuq Nanuq PA reduced in size

The Alaska Department of Natural Resources Division of Oil and Gas approved the first revision of the Nanuq Nanuq participating area Dec. 16. Nanuq is in the Colville River unit on the west side of Alaska's North Slope.

Nanuq Nanuq is one of two participating areas at the Nanuq satellite south of Alpine.

Areas on the west and north of the original participating area have been contracted out; a smaller area to the southeast has been added to the PA. The original PA, approved in 2006, was 8,157 acres; the revised PA is 6,592 acres.

"Performance from the Nanuq Nanuq reservoir has not met expectations, but the reservoir remains a viable development opportunity," ConocoPhillips told the state. Production began from the participating area in December 2006 and in 2007 production averaged some 400 barrels per day from three producers. The company said 2008 production is averaging some 500 bpd from three wells.

"Current plans are to continue to develop the Nanuq Nanuq reservoir using a phased approach, with new wells planned for 2011," ConocoPhillips said.

The company said the Nanuq Nanuq sand is on primary production with a study under way on whether to pre-produce planned injector wells. Long-term recovery plans are for waterflood with alternating miscible gas slugs.

"Despite disappointing performance to date, there are still development opportunities in the Nanuq Nanuq reservoir," the company said. Six wells have been drilled. Operations on a seventh well were suspended before the horizontal section of the well was drilled to move the rig to Fiord during the ice road season. ConocoPhillips said it expects to drill the horizontal section of that well in 2011, "or sooner depending on rig schedule and other opportunities."

—KRISTEN NELSON

continued from page 11

FORECAST

2008 price forecast $51

In its short-term energy outlook, issued Dec. 9, EIA said the global economic slowdown is expected to be more severe and longer than the agency projected in November, "leading to further reductions of global energy demand and additional declines in crude oil and other energy prices."

The annual average West Texas Intermediate price is now estimated to be $100 per barrel this year and $51 in 2009.

The Henry Hub natural gas spot price is projected to decline from an average of $9.17 per thousand cubic feet in 2008 to $6.25 per mcf in 2009.

Global crude oil demand, driven by the status of the global economy, is projected to decline by 50,000 barrels per day in 2008 and by 450,000 bpd in 2009, the first time in three decades that consumption declined in two consecutive years, the agency said.

EIA said that in both 2008 and 2009 growth in demand is focused in non-OECD countries, "especially China, the Middle East and Latin America," but the drop in demand in OECD countries is expected to more than offset any non-OECD oil consumption growth.

The agency noted the upcoming Organization of Petroleum Exporting Countries meeting set for Dec. 17 and said that while the level of compliance with the cartel's last production cuts is uncertain, it "believes that the continued weak market conditions will prompt higher-than-usual compliance among OPEC members." EIA is projecting a drop in OPEC production from 32.6 million bpd in the third quarter of 2008 to 30.6 million bpd in the first quarter of 2009. Lower demand combined with capacity expansions in several OPEC countries would produce a surplus production capacity averaging 4 million bpd in 2009. ●

continued from page 11

OPEC

formal cut of 1.5 million barrels a day that it agreed on in November.

That amounts to a new reduction of 2.2 million barrels — the largest-ever OPEC cutback at one time.

—THE ASSOCIATED PRESS

continued from page 12

EXPANSION

processed through the Alpine Central Facility.

Western focus

ConocoPhillips said wells planned in the initial Alpine development were completed as of November 2005. "Future development activities are focused on the western extension of the reservoir (accessible only from future drill sites) but other opportunities are being evaluated around the entire periphery of the Alpine PA."

Through 2012 the company said the drilling plan "will be focused on developing peripheral reserves not previously drilled due to uncertainty associated with reservoir quality and the current floodable area."

Drilling will be from the existing four pads (CD 1 and CD2 from which Alpine and Qannik are drilled; CD3 from which Fiord is drilled; and CD4 from which Nanuq is drilled).

ConocoPhillips said drilling from future drill sites, beginning with CD5 to the west (not yet built), is expected to begin in mid-2012 or later.

Nine Alpine reservoir wells were fracture stimulated in 2007 with "appreciable production rate increases," the company said. Ten wells were scheduled for fracture stimulation in 2008 and ConocoPhillips said it would continue to look for opportunities to fracture stimulate the Alpine reservoir, "contingent on economic viability."

Nanuq expanded north

The Nanuq Kuparuk participating area was expanded to the north and east. The Nanuq field is some four miles south of the Alpine field, with production from the Brookian-aged Nanuq sand and the Lower Cretaceous-aged Kuparuk sand. Initial Nanuq Kuparuk production began in November 2005.

Nanuq is produced from a gravel pad connected by a road and pipelines to the Alpine facilities.

Through October the Nanuq-Kuparuk had produced 13.1 million barrels of crude oil (compared to 280.9 million barrels from Alpine; 12.8 million barrels from Fiord; and almost 187,000 barrels from Qannik).

In its application to expand the Nanuq-Kuparuk participating area ConocoPhillips told the state that the Kuparuk sand at Nanuq "maintains thickness and good reservoir quality over a more extensive area than was originally expected." ●

LAND & LEASING

BLM accepts all NPR-A sale high bids

The U.S. Bureau of Land Management said Dec. 16 that it has accepted all high bids submitted at the Sept. 24 National Petroleum Reserve-Alaska oil and gas lease sale and will issue leases by Jan. 1.

BLM said it has mailed lease offers to the companies who submitted the high bids: Anadarko Petroleum Corp., ConocoPhillips Alaska Inc., Petro-Canada (Alaska) Inc., FEX L.P. and Petro-Hunt LLC.

These companies submitted high bids of almost $31 million for 150 tracts in the Northwest and Northeast portions of NPR-A.

If the companies accept the lease offers and return them to BLM with payment for the balance of the bonus bid, the annual rental and the lease processing fee, BLM-Alaska will issue the leases for 10-year terms.

"I'm pleased with the successful completion of the Supplement to the Northeast EIS and the lease sale process," said BLM-Alaska State Director Tom Lonnie. "The BLM's land use planning process ensures that we establish protections for the environment while permitting oil and gas development activities that will help meet the nation's energy needs."

There are currently 335 leases on 3,086,492 acres within NPR-A. The September lease sale included high bids on approximately 1.7 million acres within the 23 million-acre petroleum reserve.

—PETROLEUM NEWS

GOVERNMENT

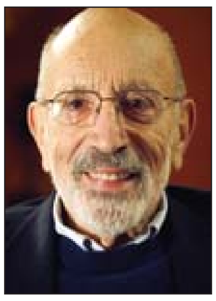
Initiatives: past, present and future

Ballot initiatives in Alaska Constitution; bill next year will propose financial disclosure, public hearing requirement changes

By KRISTEN NELSON
Petroleum News

Of the 46 initiatives that have appeared on the ballot in Alaska, a number have been energy or development related, resulting in a panel on the subject at the Resource Development Council's annual conference in Anchorage.

It was a past, present and future look at the initiative, anchored by Vic Fischer, a delegate to Alaska's 1955-56 constitutional convention.


VIC FISCHER

Initiatives were included in the Alaska Constitution so citizens could enact legislation if the state's Legislature and its executive were not responsive, Fischer told the RDC conference Nov. 19.

"There was a very populist feeling at the convention," "great idealism" and a commitment to framing a constitution "where the executive branch is headed by a governor who's going to be responsible and responsive to the people; a legislative branch that would be as effective as legislators could be." Fischer said the belief was that "government can function well," but there was also "a strong belief in direct democracy." That led to provisions for initiatives, recalls and a requirement for a vote by the people every 10 years on whether to hold a constitutional convention.

The initiative provision stated that people may propose and enact laws by initiative. It's simple and direct, Fischer said: "The people are given the law-making power," just as was given to the Legislature.

Fischer said he argued — and voted — against the initiative at the convention. "Those in favor of the initiative felt that the people should have a right to enact legislation when the Legislature was not responsive to the needs of the people, when the Legislature was not acting." Half the states in the nation at that time had provisions in their constitutions for the initiative, which came about in the early 20th century when many state legislatures were controlled by rural areas, even though the population base was urban, because legislatures were not reapportioned, leaving the majority of the people under-represented.

Fischer said it wasn't until 1964 that the U.S. Supreme Court ruled that legislatures had to be apportioned on a one-person one-vote basis.

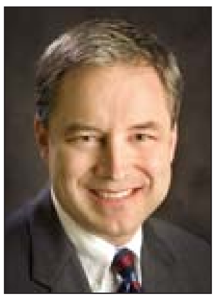
Fischer said he argued against the initiative at the constitutional convention because "it is a device that lends itself to special interests and to groups that want to get something that they cannot get through the Legislature" and because he believed that in Alaska the Legislature would "do what is best for the people."

"Generally, I've not been overly disappointed," Fischer said.

The Alaska initiative process

One hundred signatures are needed to start the initiative process, Lt. Gov. Sean Parnell told the RDC conference. The initiative with those signatures is submitted to the Division of Elections and is reviewed by the Lt. Gov.'s office and the Department of Law.

There are four prohibitions, Parnell said: An initiative cannot dedicate state revenues; it cannot make or repeal appropriations; it cannot create courts or redefine their legislation; and it cannot enact local or special legislation.


SEAN PARNELL

Initiatives are measured against those minimal criteria, but there are intricacies, he said. An initiative can't make an appropriation; so obviously you couldn't have an initiative giving out state revenues, which would clearly be an appropriation. Parnell said over the years the courts have broadened the definition of appropriation "to include everything from salmon to water to any public asset" — none can be appropriated by initiative.

If those hurdles are cleared, then signatures have to be gathered, a total of 10 percent of the turnout in the last general election, with signatures coming from 30 of the state's 40 House districts — and signatures must exceed 7 percent of the turnout in those 30 districts.

The constitution requires the initiative to be put on the general ballot 120 days after the last general session of the Legislature. Parnell said that was the general election — but since the state went to a 90-day legislative session, by initiative, initiatives are now on the primary ballot.

A weapon of first resort

And how are initiatives used? Parnell said it was formerly the case that where people, or interest groups, "cannot legislate, they tend to regulate; where they cannot regulate, they litigate; and where they cannot effectively litigate, they initiate and litigate again."

Today, he said, some initiatives are not weapons of last resort, but "have become more of a tool of first resort. And I think that's something that we're going to need to take a look at in the future."

"The people's right to pursue the initiative process is a very powerful tool," Parnell said. "It takes those significant policy choices out of the hands of lawmakers and out of the hands of state employees who write our regulatory regime and places it squarely into the hands of individual voters."

He said he is concerned by initiatives that prohibit resource development projects because "we lose the benefit of a rigorous, scientific, public permitting process. I strongly believe that companies and Alaska resource jobs depend heavily on a clear and consistent regulatory process," he said.

If project after project is decided by initiative, "then we've lost the battle for a truly informed public project based on science. Our regulatory processes then become meaningless and undependable."

With dollars from Outside apparently flooding in for initiatives, "one could conclude that Outside interests are also availing themselves of Alaska's constitutional provisions and not just our citizens. Clearly our constitution's framers did not design the right to an initiative to protect Outside interests," Parnell said.

"Alaskans have always resented uninformed voices from Outside our state and for good reasons: Alaska is best managed by Alaskans."

Initiative vs. Legislature

Ralph Samuels, R-Anchorage, outgoing House majority leader (Samuels did not run for re-election this year), asked how many at the conference had followed a bill through the "painful" committee process in the Legislature.

For those who hadn't, he reviewed the process — from drafting of a bill by the Legislature's attorneys, to committee assignments and hearings and changes. By the time a bill has gone through a couple of committees, Samuels said, "usually everything heads to the middle; middle ground usually gets found in the committee process," which, whether in Congress or the state Legislature, is painful, but it works.


RALPH SAMUELS

After the committee process the bill

see INITIATIVES page 15

● EXPLORATION & PRODUCTION

Forecasting: Can we try that again?

By GARY PARK

For Petroleum News

The Canadian oil industry's erasers are working faster than those of Sudoku players these days.

In the latest overhaul of its forecasts, the Canadian Association of Petroleum Producers has slashed oil sands output targets as a result of projects delays, deferrals and cancellations and is now starting to extend target dates for new milestone numbers.

The industry's chief lobby group now estimates 2008 production will average 1.22 million barrels per day, down 90,000 bpd from its June prediction.

For 2009, it is counting on a similar 90,000 bpd drop to 1.44 million bpd and expects the "moderate-growth path" to stretch over the next 11 years at least.

CAPP says that output will reach 1.86 million bpd in 2012 (off 160,000 bpd from its June target), 2.4 million bpd in 2015 (compared with the June estimate of 2.8 million bpd) and 2.83 million bpd in 2017 (a drop of 230,000 bpd).

By 2020 CAPP estimates volumes will hit 3.27 million bpd, falling a dramatic 1.28 million bpd short of what it forecast in June.

Those under way should be OK

CAPP Vice President Greg Stringham said most projects currently under construction should advance to completion, generating output growth of 1.2 million bpd to just under 2 million bpd in the 2007-2012 period.

But the next five-year stretch is likely to see the biggest change in forecast numbers, reflecting the impact of project deferrals over recent weeks, he said. As a result, output increases for 2012-17 will likely drop by 300,000 bpd.

From 2017 to 2020, estimates start to climb again based on CAPP's assumption that deferred projects will be revived and by 2020 oil sands output should reach 3.3 million bpd, Stringham said.

CAPP said it will re-survey companies in February and should release its updated numbers in March or April.

Stringham said the shelving of planned upgraders will also result in more heavy oil in CAPP's forecast and less upgraded light oil than it forecast in June.

Currently, about 67 percent of bitumen produced in Alberta is being upgraded in Alberta — a number that is unchanged in the latest forecast. ●

continued from page 14

INITIATIVES

goes to the House or Senate floor for a vote and amendments can be proposed: "Sometimes they pass; sometimes they fail. But everybody has their shot," he said. If the bill passes it goes to the other body and the process starts all over again.

With the initiative process, "the language is drafted by somebody; they gather 100 signatures" and if those signatures are confirmed as registered voters and the initiative passes muster the sponsors go out for mass signature collection.

Who did the drafting?

Concerns with the initiative process start with who did the drafting and did they think through all the things that could be changed with one piece of legislation? You don't know, he said, if the drafters want to change something or if "all they really want to do is screw something up."

A recent initiative, which passed, gave duties to the Department of Revenue "which didn't belong to them and now there's a little bit of confusion on who's supposed to write the regs and how are we supposed to move forward," Samuels said.

It could be done deliberately; it could be an error — but once an initiative is certified the language cannot be changed, he said.

Signature gathering is done for a fee and Samuels said those collecting signatures probably paint an accurate picture of what the initiative would do — "sometimes."

But that's not the complete initiative.

The complete initiative doesn't even appear on the ballot, he said, just a 250-word summary.

Changes being proposed

Samuels said several things could improve the initiative process.

A 2004 constitutional amendment changed the signature-gathering process to require a certain percentage of voters in 30 or 40 House districts. Before that, one vote was required in 27 districts, "so if you stand in the Dimond Center and you get enough people walking in there, you can probably cover that — in a matter of months you'll get enough of one vote in 27 districts to get the signatures," Samuels said.

The 2004 amendment required an initiative sponsor to travel around the state to get the required signatures.

Another issue that needs to be addressed is the money — there's no limit to the money that can be spent on a ballot initiative, he said. And there's no limit to the amount of money an individual or a group can give, either for signature gathering or for promoting the initiative. And there's no limit to the money that can come from Outside.

The U.S. Constitution will probably be a problem in limiting the money, Samuels said, because the standard is that "ideas cannot be corrupted so therefore you cannot limit the amount of money given to sell an idea."

There are disclosure requirements, he said, but too many loopholes, such as the ability with an initiative to give money to Group A which then gives money to Group B. The relationship between Group A and Group B has to be disclosed, Samuels said, but not the donation to Group A. "So you set up a shell company or a shell organization of some kind and you can collect and funnel money to anything that you want to."

And if you don't promote an opinion on a specific measure — just information without an endorsement — there are no disclosure requirements. "Obviously problematic," Samuels said.

No hearings

Public hearings — or legislative hearings — should also be required, he said, so that members of the public in a district can hear all sides of an issue.

And the initiative language should be on the ballot, he said, not so that a voter would read all of the language before voting, "but they would certainly know how complicated the issue is."

Rep. Kyle Johansen, R-Ketchikan, will introduce a bill which will include a lot of these concepts, Samuels said, including provisions for streamlining the disclosure process with online filing so you can get online, from day one, when they start collecting signatures, and see who supports the proposal, he said.

Public hearings would be required in various districts and legislative hearings so that departments would be able to identify areas of initiatives that would be problematic administratively.

And if an initiative fails, "it shouldn't be allowed for another election cycle."

Just in the last 10 years almost $30 million has been spent on initiatives, not counting the "loophole money" where an organization didn't advocate for or against an initiative.

"All in all there have been 46 initiatives on the ballot in Alaska; exactly half of them have passed, and there's never been a public hearing on any of them," Samuels said. ●

LAND & LEASING

Potential Alaska state and federal oil and gas lease sales

Agency	Sale and Area	Proposed Date
DNR	Alaska Peninsula Areawide	May 2009
DNR	Cook Inlet Areawide	May 2009
DNR	Beaufort Sea Areawide	October 2009
DNR	North Slope Areawide	October 2009
DNR	North Slope Foothills Areawide	October 2009
MMS	Sale 209 Beaufort Sea	2009
MMS	Sale 211 Cook Inlet	2009
DNR	Alaska Peninsula Areawide	May 2010
DNR	Cook Inlet Areawide	May 2010
DNR	Beaufort Sea Areawide	October 2010
DNR	North Slope Areawide	October 2010
DNR	North Slope Foothills Areawide	October 2010
MMS	Sale 212 Chukchi Sea	2010
MMS	Sale 217 Beaufort Sea	2011
MMS	Sale 214 North Aleutian basin	2011
MMS	Sale 219 Cook Inlet	2011
MMS	Sale 221 Chukchi Sea	2012

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

continued from page 10

LNG

modity, with worldwide price competition, once the markets of Europe, Asia and North America are connected.

At that point, unless prices change dramatically, the U.S. will be the customer of last resort, and will get shipments when producers can't get a higher price somewhere else.

"We have tremendous storage capacity in the United States. We have absolutely the world's largest and most flexible gas market and transportation system. If there's excess LNG capacity in the world, it's going to find a market," he says. It's cheaper to sell the gas at a lower price than to shut down expensive production capacity, he notes.

Damien Gaul, analyst with the Energy Information Administration, confirms that the market may be heading in the direction Hulse is suggesting — toward a spot market mentality and a surplus to be directed to the U.S.

"There's some expectation that there may be increased supplies coming up," Gaul said in a late-November interview. "A lot of it will depend on the severity of the winter; also on the severity of the downturn in the economy.

"When you talk about trends in the marketplace, there is some real flexibility," he said. "These ships are carrying 3 billion cubic feet (equivalent in LNG). It's worth $20 million or more. These cargoes are making decision on the open sea (to chart a course to a different port). It's really making a difference on a real-time basis."

Profitable operation

Meanwhile, Sempra can operate its Energia Costa Azul port with revenues from a 20-year capacity contract with Shell, which signed the deal when it was controlling owner of the Sakhalin 2 project in Siberian Russia. Sempra LNG showed a profit of $4 million for the parent company in the third quarter, with just the one ship calling in the port, along with two test cargoes.

But Gazprom is now in control at Sakhalin 2, and 60 percent of the initial production there is going to Japanese customers. The first cargo is expected to load Feb. 19. Some Sakhalin LNG could come to Sempra's port later this year, but not enough to fill Shell's 500 million cubic feet of daily capacity.

Shell later decided to send its 25 percent share of the LNG from the Chevron-led Gorgon project off Australia to Sempra's terminal, replacing or supplementing the Sakhalin cargoes. But Gorgon has been delayed repeatedly, and still doesn't have the go-ahead from Chevron, Shell and ExxonMobil to start construction. On top of that, U.S. prices have shrunk markedly.

Cargoes from the BP-led Tangguh project in Indonesia are set to take the remaining half of the capacity at Sempra's Baja port. That would bring in half a billion cubic feet a day if all of it arrives. But the agreement allows the Tangguh consortium to divert up to 50 percent of the cargoes as long as Sempra gets compensation for its costs, Hulse said. Tangguh is set to start shipping LNG in the second half of 2009.

Gulf terminal coming

Over on the Gulf of Mexico, Sempra is putting the finishing touches on its Cameron LNG terminal near Lake Charles, La., with initial capacity of 1.5 bcf daily. Italy's Eni has contracted for 600 million cubic feet of daily capacity, and Sempra is talking with other parties about the rest of the capacity, Hulse said. That project will come in at more than $800 million, he said, and will be finished in the second quarter.

Sempra has approval from the Federal Energy Regulatory Commission to build a third terminal at Port Arthur, Texas. That port would have a capacity of 3 bcf daily.

Hulse says that project is on hold. "Port Arthur is pushed out in the distance," he said. "We will not launch Port Arthur until we have enough contracts."

With current terminals already able to handle about ten times this year's imports, it may be a while before that project gains traction. ●

● NATURAL GAS

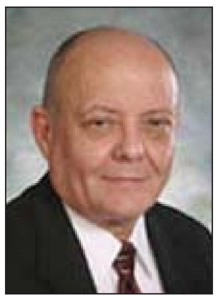
Irwin puts some weight behind Enstar

Natural Resources Commissioner asks regulators to approve amended contracts in order to allow utility to tackle longer-term issues

By ERIC LIDJI

Petroleum News

The top oil and gas official in Alaska is asking state regulators to approve a pair of supply contracts between Enstar Natural Gas and two natural gas producers in the Cook Inlet.



TOM IRWIN

"The State's best interest is achieved if the Commission approves both of the proposed gas supply contracts," Tom Irwin, commissioner of the Alaska Department of Natural Resources wrote to the Regulatory Commission of Alaska in a letter dated Dec. 11.

The RCA gave Enstar conditional approval on Oct. 31 for separate gas supply contracts with ConocoPhillips and Marathon. Enstar submitted amended contracts on Dec. 1.

Now regulators are considering whether or not the amendments are satisfactory. Enstar says the contracts need to be approved before the start of the year to avoid disruptions.

The amended contracts take a different approach to pricing Cook Inlet gas. Rather than use a cap specified in the Oct. 31 order, Enstar and the two producers created contracts based on the weighted average cost of gas, or WACOG, for all existing Enstar supplies.

Issue of RCA approval

Enstar does not need regulatory approval to enter into a supply contract that lowers its weighted average cost of gas. But because Enstar has never exercised that provision of its tariff before, the utility wants the RCA to sign off on the amended contracts.

The parties in the case agree that Enstar has the right to approve contracts that lower its weighted average cost of gas, but disagree on whether the RCA should follow suit.

Chugach Electric Association asked RCA to "maintain the integrity of this docket by not accepting Enstar's unsupported explanations and justifications" for the contracts.

The Attorney General's office said if RCA accepted the amended contracts, the agency would have to "reconcile" its decision with the Oct. 31 order, which required price caps.

"The WACOG approach is not a long term solution to Enstar's gas supply requirements."
—Tom Irwin, commissioner Alaska Department of Natural Resources

Although Irwin recommended approving the contracts, he showed some reluctance, too.

In his letter, Irwin wrote, "The WACOG approach is not a long term solution to Enstar's gas supply requirements. Long term solutions must reflect the cost to find and develop the new resources that will be required to meet the public demand for gas supply."

The Department of Natural Resources is not a party to the case over the contracts.

Chugach Electric does not believe enough evidence exists to prove that "the cost to find and develop the new resources" in Cook Inlet justifies an increase to local gas prices.

RCA is expected to rule on the amended contracts before the end of the year. ●

Contact Eric Lidji at 907-522-9469 or elidji@petroleumnews.com

● PIPELINES & DOWNSTREAM

3rd new Prudhoe transit line in service

By KRISTEN NELSON

Petroleum News

The third of four BP Exploration (Alaska) Prudhoe Bay replacement transit lines went into service Dec. 12 and the fourth and final replacement line is scheduled to be in service by Christmas, BP spokesman Steve Rinehart told Petroleum News Dec. 17.

The transit line replacements are the result of corrosion found in transit lines at the field in 2006.

A spill in March 2006 of more than 200,000 barrels on the western side of Prudhoe Bay from a transit line coming from Gathering Center 2 was followed in early August of that year by a number of anomalies and a small leak found on the eastern side of the field as BP was testing lines in compliance with a U.S. Department of Transportation order stemming from the March spill.

BP decided in August 2006 to replace the transit lines.

The cost had been pegged at some $260 million, although Rinehart told Petroleum News earlier this year that costs had climbed since that estimate was done.

Cost about $500 million

The cost is now put at about $500 million, Rinehart said.

The earlier estimates "did not take into account all the added facilities, additional modules and construction," he said in an e-mail. Rinehart also said that "significant resources" were added to make sure the work was completed by the end of the year.

He said BP "will end up with a modern system designed to serve Prudhoe and surrounding fields for decades."

The work "incorporates facilities to enable maintenance and ensure integrity, using best-available technology in leak detection, metering and corrosion control," Rinehart said.

The replacement transit lines have been coming into service since March, beginning with three miles of 20-inch line on the west side of Prudhoe Bay between Gathering Center 2 and Gathering Center 1. In September, three miles of 12-inch line went into service on the east side of the field between Flow Station 2 and Flow Station 1.

The line which went into service Dec. 12 was five miles of 28-inch line between Gathering Center 1 on the west side and Skid 50.

The final replacement transit line is another five-mile section, this an 18-inch line, from Flow Station 1 on the east side to Skid 50.●

ALTERNATIVE ENERGY

Nikiski possible site for wind power

New York-based BQ Energy says as many as 10, 250-foot towers could be built near Tesoro; supply power to Southcentral grid

THE ASSOCIATED PRESS

A New York company is planning to bring wind power to Nikiski.

After collecting data for a year, BQ Energy finds that Nikiski has favorable conditions for building a multi-tower complex near the Tesoro refinery.

BQ Energy, headquartered in Patterson, N.Y., specializes in researching industrial areas for their potential as alternative energy generation sites. If built, the complex and Homer Electric Association could one day supply energy to the refinery and the Southcentral grid.

BQ spokesman Paul Curran said the data from the Nikiski site looks very encouraging.

The company envisions perhaps as many as 10 towers, each about 250 feet tall.

"We take that data to build up a curve of what likely long-term wind patterns would be," he explained. "We were surprised by the initial data. We assumed the wind would come up the inlet, but it comes down from the northeast as well. It follows the inlet up and down."

The collected data will be used to estimate the total energy available, and to figure how generating towers should be arranged and spaced.

BQ would own the project through a subsidiary, Kenai Winds LLC.

Cost pegged at $46.8 million

Alternative energy projects remain attractive to investors, Curran said.

"People are looking at it as long-term and steady investment," he said, though he acknowledged finding investors is not as easy today as it was a few months ago. He also noted that tax credits meant to encourage companies to start the switch to or add capacity for alternative energy sources are less of an incentive when companies aren't making as much money.

BQ, however, believes it could have the towers up and running in as little as two years, provided they secure contract commitments to buy the energy. Tesoro is interested, and the tower site is in close proximity to the refinery, making the complex a logical customer, Curran said.

The company is talking with Homer Electric Association about connecting to the energy grid, and working with the Alaska Energy Authority, through which they hope to secure an $11.7 million state grant. The total cost of the project is estimated at $46.8 million.

Homer Electric spokesman Joe Gallagher said HEA was fully supportive of the efforts of BQ Energy in working with Tesoro on the wind project.

"We think any program or development of wind power on peninsula is for the public good and will be beneficial for everybody," Gallagher said. ●

GOVERNMENT

Habitat protection proposed for otters

THE ASSOCIATED PRESS

A federal agency is proposing habitat protection for Alaska sea otters in the Aleutian Islands, where numbers have dwindled by more than half in 20 years.

The U.S. Fish and Wildlife Service proposal issued Dec. 16 would designate 5,879 square miles of ocean near the shoreline in Southwest Alaska as critical habitat.

About 90 percent of the world's sea otters live in coastal Alaska. The ones in the Aleutian Islands were declared threatened three years ago under the Endangered Species Act.

Eight years ago, the Center for Biological Diversity petitioned the government to protect Southwest Alaska's sea otters. The move came after numbers dropped from an estimated 100,000 animals in the 1970s to about 40,000 now.

The reasons for the drop-off are not known, although increased predation by killer whales is suspected to be a factor.

Oil seen as threat

The conservation group maintains that proposals to open Bristol Bay in the Bering Sea to oil development, overfishing and changes caused by global warming are threatening sea otters.

Fish and Wildlife is proposing that all nearshore waters in the sea otter's current range in Southwest Alaska be designated as critical habitat. The agency says the nearshore waters are particularly important because they provide sea otters with cover and shelter from marine predators, particularly killer whales.

Once critical habitat is designated, all federal agencies would be required to ensure that any activities in the area would not harm sea otters.

Fish and Wildlife does not anticipate that the designation would result in any commercial fishing closures in Southwest Alaska. That's because the foods that sea otters eat, mostly sea urchins, crabs, octopuses and some bottom-dwelling fish, have little or no commercial value.

The agency says the areas proposed for critical habitat also are not areas where significant commercial fishing occurs.

Brendan Cummings, the Center for Biological Diversity's oceans program director, said the designation is a good beginning but doesn't go far enough. The critical habitat designation should extend not just a few hundred feet offshore but to at least a mile, he said.

By the early 1900s, the commercial harvest had reduced sea otter numbers to a few hundred. In Alaska, there are about 70,000 animals now.

The agency is accepting comments on its proposal until Feb. 17. The critical habitat designation must be finalized by Oct. 1. ●

GOVERNMENT

Obama names energy, environment team

President-elect Barack Obama on Dec. 15 named an environmental and energy team that he said signaled his determination to tackle global warming quickly and develop alternative forms of energy. He vowed to "move beyond our oil addiction and create a new hybrid economy."

Obama selected Nobel-prize winning physicist Steven Chu as energy secretary and Carol Browner, a confidante of former Vice President Al Gore, to lead a White House council on energy and climate. Browner headed the Environmental Protection Agency in the Clinton administration.

Chu is director of the Lawrence Berkeley National Laboratory in Berkeley, Calif., and is a leading advocate of reducing greenhouse gases by developing new energy sources. "His appointment should send a signal to all that my administration will value science. We will make decisions based on the facts, and we understand that facts demand bold action," Obama said.

Obama also announced his choice of Lisa Jackson, former head of New Jersey's environmental agency, as EPA administrator.

"We can spark the dynamism of our economy through a long-term investment in renewable energy that will give life to new businesses and industries with good jobs that pay well and can't be outsourced," he said. "We'll make public buildings more efficient, modernize our electricity grid, and reduce greenhouse gas emissions, while protecting and preserving our natural resources. We must also recognize that the solution to global climate change must be global."

—THE ASSOCIATED PRESS

Business Spotlight

URS Alaska Operations

URS is a San Francisco-based engineering, construction and technical services business with more than 50,000 employees and offices in more than 30 countries. Last year its revenue totaled $5.4 billion and profits were $132 million, according to U.S. Securities and Exchange Commission financial statement filings. With the acquisition of Alaska-based Tryck Nyman Hayes, Inc. (TNH), both companies are better positioned for Defense Department and private pipeline projects in Alaska.

FORREST CRANE

Mary Pagel, PE, Manager Fairbanks Office, URS

Mary Pagel

Transportation engineer Mary Pagel joined URS in 2006, bringing 20 years' experience on roadway improvement projects, storm drainage upgrades, utility redesigns and engineering quality assurance evaluations. She favors challenging projects in the far reaches of Alaska. When off duty, Mary finds solo canoe paddling, sea kayaking and skijoring both challenging and exciting; at minus 20 degrees she cocoons in her Fairbanks-area cabin with a good book and sled dog Danni.

Sonia Jaeger

After two decades with the U.S. Army Corps of Engineers in San Francisco, Sonia Jaeger moved to Alaska and has worked for URS (TNH) since 2000. This single Anchorage professional has a son, Justin, and three pets — an African hunting dog, a husky/pit bull and a cat — all which contribute to organized chaos at the Jaeger home in Anchorage. Although Sonia enjoys many outdoor sports, indoor rock climbing is her latest pastime. Traveling, learning about other cultures and caring for needy children and pets round out her strategy for a good life.

FORREST CRANE

Sonia Jaeger, Senior CADD Technician Anchorage Office, URS

—PAULA EASLEY

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

Petroleum news

Oil Patch Bits

Allan Dolynny named president of NANA/Colt

On Dec. 5, Allan M. Dolynny assumed the responsibilities of president at NANA/Colt Engineering LLC, replacing John Minier, who has retired after eight years on the job.

ALLAN DOLYNNY

Dolynny was named general manager at NANA/Colt in October 2008, a month after Minier announced his intent to retire from the Alaska company, which is a 50-50 partnership between Alaska-based NANA Development Corp. and Australia-based WorleyParsons Ltd. "John did a fantastic job of steering this company successfully for nearly a decade," Dolynny said in a Dec. 15 press release. "It is my hope to lead this talented, diverse team of professionals as well as he did." Joining NANA/Colt from WorleyParsons Calgary, Dolynny brings more than 22 years' experience in engineering, procurement and construction project management to his new position. For more information visit www.nana-colt.com.

Schlumberger opens heavy oil technology center

On Dec. 3, Schlumberger inaugurated a new oilfield technology center in Calgary, Alberta, that will focus on efficient heavy oil recovery in Alberta and Alaska. The company said the state-of-the-art center will work directly with oilfield technical teams and regional research facilities to help customers increase heavy oil production, reduce technical risk and minimize environmental footprint. The Heavy Oil Regional Technology Center, or RTC, will provide a working environment where clients can work hand-in-hand with Schlumberger geoscientists and petroleum engineers to solve "key technical challenges associated with heavy oil recovery. These research projects include, but are not limited to, innovative geological and geophysical services, advanced well placement strategies, new formation evaluation and characterization techniques, and novel integrated completions and monitoring programs," Schlumberger said. For more information visit www.heavyoilinfo.com.

See full stories in the next Petroleum Directory magazine, which will carry a new name, Arctic Oil & Gas Directory.

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STRATEGY

be "challenged to build significant new refining and upgrading capacity relative to expanding facilities that exist elsewhere.

"Part of what the policy is going to have to address as (the government) gets more specific is how do you overcome that potential disadvantage?" he said, referring to oil sands producers who are opting to drop plans for facilities in Alberta and, in most cases, look for alternatives in the United States, where construction costs are cheaper.

But the government is still clinging to its belief that "carefully planning upgrading and refining capacity (for Alberta) provides options for realistically adding value to fossil fuels while contributing to cleaner energy.

"This provides even greater reason to encourage additional investments that will see more of Alberta's products advance up the energy value chain," the strategy said.

Details missing from plan

Petro-Canada Chief Executive Officer Ron Brenneman credited the government with setting a "pretty responsible direction" with its new policy.

"But there's a lot of details missing," he said. "I'm always hesitant to comment until I see some of the details, because the devil is often there."

In the wake of delays and cancellations of upgraders, refineries and petrochemical plants, accompanied by fears that jobs and investment will flow to the United States, Brenneman urged the government to give immediate priority to tackling the reasons why Alberta has become less competitive in the last couple of years.

Petro-Canada, as operator of the proposed C$24 billion Fort Hills oil sands project, is setting its own example by renegotiating contract and supply agreements.

In just a few weeks it has seen a "pretty good response" as costs start to move down, Brenneman said.

"I don't know where it will end up or whether it's enough to make a difference in the overall project economics," he said. "But the thing that is changing for us is that we are moving off the schedule of the project on to a cost-driven project."

If the decision is made to resume work "we are going to accept whatever schedule gives us the minimum cost," Brenneman said.

However, he emphasized that Petro-Canada will not start looking for refining capacity in the United States until it is close to proceeding with the mine.

That leaves some faint hope for the Alberta government that the Fort Hills upgrader could still be built in Alberta. At least, for now, Petro-Canada is not choosing to follow the lead of oil sands producers EnCana and Husky Energy, which have formed joint-ventures with U.S. refiners.

Bitumen-in-kind

In its determination to increase the amount of bitumen upgrading and refining in Alberta, the government is working on a ploy that would see it take bitumen-in-kind rather than cash royalties to control 25 percent or more of the market.

It has set a target of locally upgrading 70 percent of the heavy oil produced in the province, up from the current 65 percent.

While the government ponders exactly how to implement this policy, existing oil sands producers working on expansion phases are unsure how much upgrading capacity to build.

On the environmental front, the strategy recommends: Encouraging the development of renewable energy; investing in gasification technology and carbon capture and storage; changing energy consumption behavior by industry and Albertans; and greater investment in research, development, demonstration and deployment of energy technology.

"The key question for Alberta, in a world that is going to be counting on energy from all sources, is how we can begin to produce and consume fossil fuels in a far cleaner way," the report said.

Cap-and-trade rejected

To that end, Stelmach flatly rejects cap-and-trade plans that would impose charges on carbon emissions, saying "we are not going to allow others to determine Alberta's future."

He said investing in education, research and technology will "help us deal with the environmental impact, not moving money around from one country to another."

Instead, Alberta has its own mechanism that targets the largest industrial emitters of greenhouse gases, who, when they fail to meet intensity reduction goals, can pay C$15 per metric ton into a technology development fund.

University of Alberta business professor Michael Percy, chairman of the energy strategy advisory committee, concedes the proposals are wide-ranging.

He said they are designed to serve as a guideline for the next 20 or 30 years by "setting up goalposts along the way … you can't be that precise in setting timelines."

On the action front, the strategy recommends Alberta require gasoline to contain 5 percent ethanol and diesel to contain 2 percent renewable content by 2010 to remove about 1 million metric tons a year of carbon dioxide from the atmosphere. ●

EXPLORATION & PRODUCTION

Shell to appeal court ruling, cancels 2009 Beaufort Sea work

After analyzing the Nov. 20 ruling from the U.S. Court of Appeals for the 9th Circuit, Shell said today that it has decided to file a petition for a rehearing to the full court. And because of the court's decision, the company has decided to defer both its 2009 Beaufort Sea drilling and seismic programs.

BREAKING NEWS

"We believe the MMS performed a complete analysis of our exploration plan. That analysis prompted the agency to properly conclude that any impact from exploration activity in the Beaufort would have minimal impact on marine mammals and subsistence activities," the company said in a press release.

Shell agreed with the dissenting judge that the court "exceeded its field of expertise, and in doing so, ignored the expertise of federal regulators. Furthermore, the court's recent decision "places excessive requirements on any future exploration program."

The reduced 2009 program "means hundreds of jobs associated with support for the operation, including marine mammal monitoring, communications centers and drilling operations, won't materialize. It also means our overall Alaska operating investment will be reduced by tens of millions of dollars. This will have a direct effect on the communities of the North Slope and other areas of the State. Our current level of investment in Alaska is not sustainable given our inability to drill."

See full story on the Nov. 20 court ruling in the Nov. 30 issue of Petroleum News online at http://www.petroleumnews.com/pnads/247889057.shtml.

—PETROLEUM NEWS

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INSIDER

reassuring context: ConocoPhillips makes similar warnings every year at this time.

Every December, as ConocoPhillips crafts its global spending plan, the heads of the company's Alaska subsidiary call employees to a "town hall" meeting to talk about the company's business and Alaska — and to warn about the need to cut costs.

The difference this year is the global spending plan got sidetracked by an economic landscape proving to be more unpredictable than even the oil patch is accustomed to seeing. On Dec. 15, ConocoPhillips decided to postpone the release of its 2009 worldwide budget from mid-December to January, hoping to get a better handle on how oil and natural gas prices could impact operations.

ConocoPhillips is the second major oil company to hold off announcing its 2009 capital program due to the changing economic environment. Chevron also recently said it would wait until the end of January, rather than December, to release official spending plans.

Fortunately for Alaska, the other major players appear to be taking a longer-range view of prices.

In late November, BP announced an increase to planned spending for Alaska, around $1.2 billion for 2009 compared to $900 million spent in 2008. ExxonMobil is expected to unveil its capital program in March, but analysts say the company doesn't appear to be scaling back.

Over the past few months, ConocoPhillips has suggested its 2009 capital budget wouldn't change much from spending planned for the current year. ConocoPhillips budgeted $15 billion in capital projects for 2008, including $1 billion for projects in Alaska.

But if ConocoPhillips reduces its capital budget for Alaska, its partners at the Prudhoe Bay and Kuparuk River units might be forced to follow suit.

That's the bad news.

The good news is that while ConocoPhillips is asking its employees to reduce costs and negotiating for lower prices from its Alaska contractors, a trend playing out between producers and contractors around the world, the company appears to be moving ahead with its 2009 exploration and development plans for Alaska, suggesting its capital expenses for the state might be the same as in 2008.

ConocoPhillips' stock continues to receive positive ratings in financial markets, ratings supported by the company's size, strong cash flow, and the diversification of its integrated business model.

For the 12-month period ending Sept. 30, ConocoPhillips generated record pre-tax earnings of $39.3 billion and free cash flow of $9.2 billion. More importantly, the company's debt-to-capitalization ratio at the end of the third quarter was down to 19 percent; its operational performance remained strong, and its assets were a healthy $184.6 billion.

But analysts have expressed some concern about the company's high level of planned capital expenditures, the political risk associated with its Russia assets, rising oilfield service and supply costs, large global E&P development program and substantial commitments to its share repurchase and dividend programs, all of which could place additional pressure on cash flow.

The credit crunch and falling commodity prices have forced some oil and gas producers to scale back capital spending for 2009, but analysts believe major oil companies doing business in Alaska, such as BP, ConocoPhillips, ExxonMobil, Shell, Eni and Chevron, can afford to take a longer view because of the extraordinary profits they have reaped from high prices over the past four years.

For now, Petroleum News' sources indicate 2009 capital and operating expenditures in Alaska look much the same as 2008. But the landscape changes daily and, ultimately, only time will tell.

Alliance office moving in December

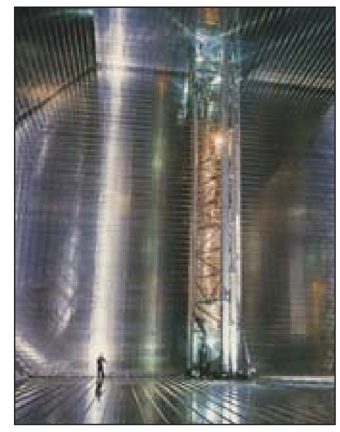
THE ALASKA SUPPORT INDUSTRY ALLIANCE is moving from midtown to downtown Anchorage.

Effective Dec. 29 the Alliance will be at 646 W. 4th Ave., Suite 200, Anchorage, Alaska 99501.

The association's phone, fax and e-mail contact information will not change.

The Alliance office will be closed from Dec. 19 to Dec. 29.

PHOTOS COURTESY EXXONMOBIL



Above, the recent completion of the world's first Q-Max LNG carrier, named 'Mozah,' marks a step change in LNG shipping by reducing transportation cost, while improving energy efficiency and reducing emissions.

At left, the Q-Max carriers are equipped with the largest membrane containment tanks ever built. One of the five ship-board LNG membrane containment tanks is pictured.

ExxonMobil completes world's largest LNG carrier

EXXONMOBIL SAID in mid-December that its "technology leadership" in liquefied natural gas has resulted in the design of a new type of LNG carrier — the Q-Max.

The first of six Q-Max carriers, called the 'Mozah,' represents "an industry breakthrough in carrier design and size, enabling the more efficient transport of natural gas" to worldwide markets, ExxonMobil said.

It "marks a step change in LNG shipping," the company said.

Q-Max ships will carry up to 80 percent more cargo, yet require approximately 40 percent less energy per unit of cargo than conventional LNG carriers due to economies of scale and efficiency of the

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engines.

"The Q-Max carriers break the LNG shipping mold in nearly every way," said Neil Duffin, president of ExxonMobil Development Co.

The large LNG ship technologies, developed in conjunction with joint venture partner Qatar Petroleum, include "increased ship size, onboard reliquefaction units, slow-speed diesel engines, twin propellers and rudders, largest ship-board LNG tanks ever built, the latest in hull antifouling protection and improved fire-protection systems. The end result of these new generation ships is a 20-30 percent reduction in transportation cost," ExxonMobil said.

"Shipping is a critical link in the LNG value chain that extends from Qatar's North Field, the largest non-associated gas field in the world with recoverable resources of more than 900 trillion cubic feet, to homes in Asia, Europe, and the Americas. With our innovative technology, we have effectively transformed the LNG business and opened up more of the world for Qatar LNG," said Faisal Al Suwaidi, Qatargas chief executive officer.

With a total capacity of up to 266,000 cubic meters, each ship carries enough natural gas to meet the energy needs of 70,000 U.S. homes for one year, ExxonMobil said.

—KAY CASHMAN

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QUANDARY

oil base rate of 25 percent, for a tax rate of 34.59 percent.

The value of natural gas at the wellhead, however, is too low to trigger the progressivity factor. When 75 cents is subtracted from the Henry Hub spot price to adjust for the gas going to Alberta, the transportation cost to market, estimated at $2.88 per mcf, is more than half the price the gas brings at market, dropping the value at the point of production so low that there is no progressivity factor.

Combining oil and gas under the same production tax system — with no progressivity for natural gas — drops the progressivity rate from 9.59 percent to 1.74 percent, reducing the overall tax rate from 34.59 percent on oil alone to 26.74 percent on the oil and gas combined. Combined, the production tax is figured on a larger base, but at a smaller rate.

Dickinson said state revenues from royalties and property tax would increase with natural gas sales, but corporate income taxes would drop.

Wood concurs

Dickinson provided an overview for the committee of Alaska's production tax system and recent changes, including progressivity, a presentation which was an introduction to a preliminary report on a study commissioned by LB&A in April on a fiscal design for Alaska North Slope natural gas.

Large gas volumes contribute low value to high-value oil production and can dilute production tax value on a boe basis and reduce the progressivity factor for the combined stream, David Wood of David Wood & Associates told the committee.

Wood said the trigger point at which the progressivity tax is payable is set too high for natural gas.

Looking at fiscal design internationally, Wood said three focuses are possible: optimizing government take; encouraging inward investment; and developing indigenous industry. Alaska's focus, he said, is on the first two — optimizing its take and encouraging producers to invest earnings in the state. Many developed countries focus on inward investment, he said, while Norway and North Africa focus on developing local industry and maintaining control. Big developing countries, many of them Organization of Petroleum Exporting Countries like Venezuela, maximize sovereign take.

Stability important

Wood said important parts of a fiscal design include providing stability and consistency, aligning with all stakeholders and having flexibility to adapt to changing circumstances.

Fiscal mechanisms which dominate international fiscal designs are mineral-interest systems, like that in the United States, where rights to production are transferred to a lessee or licensee in exchange for development of the resource and payment of a royalty and usually other taxes, and production-sharing mechanisms which are contractually driven. There is about a 50-50 split between production sharing agreement systems and mineral-interest systems and while there is a range of other fiscal mechanisms, these are the main two under which big gas projects are developed, he said.

The focus of fiscal designs, Wood said, is on the division of economic rent between government and industry and investment is promoted by designs which are progressive and flexible.

Regressive vs. progressive

Regressive elements and fears of instability can limit investment. Regressive elements in Alaska's fiscal design include royalty, property taxes and the production tax floor.

Wood said those regressive elements are partially offset by investment credits for exploration and development; production taxes which are levied after deduction of allowable costs; and the progressivity tax which is only levied on high-value streams.

He said the state should consider other allowances or credits to offset impacts of the regressive elements coupled with tougher progressivity terms under the most recent production tax revisions.

The government sees income later in a progressive system, sooner in a regressive system, Wood said. It is unrealistic to have all government income from progressive elements, but it is a problem for producers to have all government income from the regressive end of the spectrum. There is less flexibility with regressive systems and more flexibility with progressive systems, he said.

The minimum reserve size is negatively impacted by regressive systems: While highly progressive systems act to bring down the minimum economic field size and help keep those fields in production, highly regressive systems move the minimum economic field size up, Wood said.

He said the new Alaska fiscal design is more regressive because of the increase from 22.5 percent to 25 percent in the base production tax rate.

Treatment, transport, tariff

The costs are higher in natural gas, he said, so the economic rent is smaller and there is perhaps less room for adjustments.

Under Alaska's fiscal system the government take is about 30 percent of total revenues for natural gas (state 22 percent, federal government 9 percent). For oil, however, government take is closer to 60 percent (Alaska 46 percent, federal government 11 percent) because costs are lower.

Starting with destination value, 42 percent of the value of natural gas from a large field is consumed by treatment, transport and tariff costs, with about 1 percent TT&T for liquids from the field. This compares, for a large oil field, with 5 percent TT&T for the liquids and 6 percent TT&T for any gas from the field.

While the producer take is 16 percent in Wood's example for a large gas field, it is 20 percent for a large oil field.

Stability important

Wood said fiscal stability and credibility are important to international oil companies making investment decisions, but are not the only factors that influence investment decisions.

International oil companies often seek fiscal certainty in exchange for committing to large investments, he said, but warned that issuing guarantees or being drawn into long-term contracts is risky for governments. He said a flexible and progressive fiscal design is a better approach and said "clear, pro-commercial fiscal strategy statements" improve industry confidence. Any guarantees offered should have limited time periods, involve reciprocal commitments from the companies for ceilings on costs and involve more regressive fiscal elements than if no guarantees are given.

He said that retaining the right to adjust fiscal terms allows governments to "periodically change the fiscal design to respond to market conditions."

Wood said international oil companies have "demonstrated more enthusiasm around the world for downstream infrastructure project investments that are integrated with development of upstream resources." Companies have signed on, worldwide, to progressive systems with high marginal government takes — and significant government equity shares — when gas values are high and there is limited access to reserves, he said, but have been more likely to do so with incentives during low gas prices, with exclusive rights to resources in integrated upstream and downstream projects and when terms are controlled by contracts. ●

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NWT RAGE

She said jobs and contracting opportunities are coming to a total standstill, leaving everyone to shake their heads.

Cournoyea went as far as suggesting that "indirectly" the JRP is "probably killing the pipeline and the activity that is taking place in our region."

NELLIE COURNOYEA

The Inuvialuit Regional Corp. said in a statement that residents in its region and the Beaufort Delta communities "have once again been let down by the process that was created to ensure the timely environmental review" of the project.

Inuvik requests termination

The Inuvik Town Council on the Delta demanded that members of the JRP should be fired, with the town's senior administrative officer Sara Brown saying she is not aware of anyone who isn't "frustrated at this point."

In one of the strongest condemnations yet of the JRP she said there is "certainly quite a high degree of incompetence" on the panel, echoing the Inuvik council which accused the JRP of "gross incompetence."

The council resolution read: "Therefore be it resolved that the Town of Inuvik calls on the Inuvialuit Game Council, the Mackenzie Valley Impact Review Board and the Honorable Jim Prentice (Canada's environment minister and the cabinet member entrusted with handling the MGP application), to repeal the Joint Review Panel agreement and terminate panel members.

Cournoyea went as far as suggesting that "indirectly" the JRP is "probably killing the pipeline and the activity that is taking place in our region."

"Be it further resolved that the necessary steps be taken by the above-named authorities and the National Energy Board take the necessary steps to ensure the panel report is completed in a timely fashion."

Brendan Bell, the former NWT industry minister, said the mood among northern residents is one of "disappointment and outrage" and said they had come to the conclusion that the JRP is either "incapable of or uninterested in ever producing a final report."

He said the MGP is a "natural fit" for Canada at a time when infrastructure spending is urgently needed to stimulate the economy, but "this regulatory distress is jeopardizing the whole thing."

There was no immediate response from the Canadian government, which may see the dismissal of JRP members as a further delaying tactic. But Ottawa does have the option of cracking the whip, to ensure the MGP maintains its shrinking, but critical edge over an Alaska gas pipeline. ●

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TRANSCANADA

they may be interested in seeing the inflator being equivalent to oil and gas inflation," Palmer said.

Since 2004, the Consumer Price Index has risen around 15 percent, bringing the $18 billion guarantee to just less than $21 billion. But Palmer believes costs in the oil and gas industry have risen much faster than consumer prices over the past four years.

Others in the industry seem to agree. Speaking before the Resource Development Council in late November, outgoing BP Exploration (Alaska) President Doug Suttles estimated the cost increases have been between 15 and 20 percent per year for the oil industry.

It remains unclear, though, whether the global economic turmoil currently dampening oil and gas prices will have a similar impact on labor costs or building materials like steel. If those costs drop, it could significantly impact the overall cost of the natural gas pipeline.

Asked if TransCanada could finance the project, estimated to cost between $26 billion and $40 billion, without an increase in the federal loan guarantee, Palmer said, "Yes, of course we can. The loan guarantee does assist in obtaining debt for the project, and it does assist in lowering the interest rate for the project to the benefit of all stakeholders."

TransCanada completed a cost estimate in 2007. The company will soon begin fieldwork to get new estimates before holding an open season on the pipeline by the spring of 2010.

As proposed, the pipeline would run around 1,700 miles from the gas fields on the North Slope to an existing pipeline hub in Alberta, where gas could be fed across the continent.

Idea concerns senators

In an interview with Reuters published Dec. 9, TransCanada CEO Hal Kvisle said, "The ... question for us is can we get the U.S. government to ideally increase (the guarantees) in step with inflation, recognizing that inflation has taken a big bite out of them."

Coming just days after the company received an exclusive state license and accompanying $500 million matching grant to move forward on trying to permit an Alaska gas pipeline, Kvisle's remarks elicited cautious concern from Alaska's new U.S. Senate team.

"I am troubled by the recent reports of TransCanada floating the idea of even bigger federal loan guarantees," Senator-elect Mark Begich told reporters in Anchorage on Dec. 11. "That wasn't necessarily met with great enthusiasm in Washington."

Asked if he would support such an increase, Begich, a Democrat, said, "I would be very cautious about looking at the future until I see some real project potential."

Sen. Lisa Murkowski, a Republican set to become Alaska's senior senator in January and sponsor of the 2004 bill, also remained cautious about increasing the loan guarantees.

"Given the financial meltdown, the marked drop in oil and gas prices and the size of the federal deficit in the wake of the economic rescue efforts, it's difficult to predict whether Congress would be interested in providing more financial assistance for an Alaska line," Murkowski spokesman Michael Brumas told Petroleum News on Dec. 15.

TransCanada hasn't formally pitched the idea of changing the existing terms of the federal loan guarantees. Palmer said the company planned to hold off on deciding whether to raise the issue until after the inauguration of a new Congress and president in January.

Idea floated last January

The issue of increasing the federal loan guarantee is not new.

TransCanada raised the point in its application under the Alaska Gasline Inducement Act, or AGIA, the vehicle Gov. Sarah Palin created to spur progress on a gas pipeline.

The company also floated the idea of using the federal government as a "bridge shipper" if the pipeline failed to secure large enough volumes of gas to support the project.

These ideas prompted controversy when they came to light this past January.

Some believed TransCanada depended on the federal government taking responsibility for the pipeline, which should have disqualified the company under the terms of AGIA.

But the state called the measures "creative ideas … to help facilitate the development of the project," and said TransCanada planned to proceed without additional guarantees.

In the Reuters article, Kvisle called the project "fundamentally economic" and said TransCanada only needs the guarantee "to deal with some of the uncertainty."

Kvisle also suggested expanding the scope of the federal loan guarantees to include paying off debt if TransCanada fails on the project, or helping to cover any fiscal gaps if the fees paid by shippers on the pipeline don't cover the full construction cost. ●

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