Petroleum news

page 4 Q&A: Wielechowski pushes recall, focus on Cook Inlet, big gas line

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Talking LNG

JUDY PATRICK COURTESY OF K&L GATES

An Anchorage audience got a Washington, D.C., perspective on LNG development at the K&L Gates Second Annual Alaska Oil and Gas Conference July 10. LNG panel participants, left to right: Steven Sparling, K&L Gates; Larry Persily, federal coordinator in the Office of the Federal Coordinator for Alaska Natural Gas Transportation Projects; Christopher Goncalves, Berkeley Research Group; and David Wochner, K&L Gates. See story page 9.

Buccaneer completes Cosmo No. 1 planning Lower Tyonek flow test

Buccaneer Energy Ltd. recently finished drilling the Cosmo No. 1 well and now plans to test a relatively shallow oil discovery at the Cook Inlet prospect, the company said July 16.

The local subsidiary of the Australian independent said it has drilled the offshore well to a total depth of 7,599 feet, slightly shallower than its initial target of 8,000 feet. Now, Buccaneer plans to install a 7-inch liner in the well to accommodate a production test of an oil discovery at the base of the Tyonek formation, according to the company.

Buccaneer said it collected 60 sidewall core samples, six hydrocarbon samples (one gas and five oil) and 27 pressure results using a Modular Formation Dynamics Tester.

As previously announced, Cosmo No. 1 encountered oil-bearing sands in the Lower Tyonek, some 400 feet shallower than the oil shows in previous Cosmopolitan wells. All told, according to Buccaneer, Cosmo No. 1 encountered some 488 feet of "indicated oil and gas pay," including 18 gas zone and

see **BUCCANEER MOVES** *page 19*

ConocoPhillips to pay $263M to BP for TAPS cost pooling

In a major milestone in continuing wrangles over the rates that owners of TAPS, the trans-Alaska pipeline, charge for shipping oil in the pipeline, the Federal Energy Regulatory Commission, or FERC, has approved an agreement by the owners over the pooling of costs associated with pipeline operations. And under a settlement between the owners over how pipeline costs were allocated prior to Aug. 1, 2012, the retrospective date that the new pooling arrangement goes into effect, ConocoPhillips has agreed to pay BP $263 million. ConocoPhillips will pay ExxonMobil nearly $9 million, while BP will pay ExxonMobil $1.8 million.

Pipeline ownership

Following changes in pipeline ownership over the past year, the pipeline is now owned by BP, ConocoPhillips, ExxonMobil and Unocal. Unocal, a subsidiary of Chevron, has previously announced its intention to sell its relatively small ownership interest in the pipeline to the three other owners, subject to the settlement of a dispute regarding its interests in the cost pooling agreement. And as part of the newly announced settlement, BP has agreed to pay $5 million to Unocal, thus paving the way for Unocal's departure from pipeline ownership.

see **COST POOLING** *page 18*

NATURAL GAS

Through to 2018

Chugach Electric's new Hilcorp contract will ensure adequate gas supplies

By ALAN BAILEY
Petroleum News

Chugach Electric Association, a major electric-city utility in Southcentral Alaska, has asked the Regulatory Commission of Alaska to approve a new gas supply agreement with gas producer Hilcorp Alaska. The new agreement, together with Chugach Electric's existing contracts, will ensure that the utility has sufficient gas to meet its anticipated power generation needs through the first quarter of 2018, Chugach Electric says.

Faced with pending gas supply shortages from the Cook Inlet basin, Southcentral utilities had been anticipating having to import gas into the

After the end of 2016 the new Hilcorp contract would be Chugach Electric's sole source of gas, unless the utility chooses to take less gas than it needs by using the contract's flexible terms.

region within the next couple of years or so. But with Hilcorp, a newcomer to the basin, pursuing an aggressive development program across many of the basin's gas fields, the utilities have recently been talking about the projected gas shortfall moving out to 2018. The new supply agreement with

see **GAS CONTRACT** *page 19*

NATURAL GAS

All clear for Shadura gas

FWS grants NordAq access to proposed development on Alaska's Kenai Peninsula

By WESLEY LOY
For Petroleum News

A recent decision from the U.S. Fish and Wildlife Service could usher in a new natural gas development on Alaska's Kenai Peninsula.

An agency official on June 28 signed a "record of decision" that gives NordAq Energy Inc. the access it wanted to the proposed Shadura development.

The site is northeast of the Nikiski community, inside the Kenai National Wildlife Refuge. The Fish and Wildlife Service manages the refuge.

More than a year ago, in May 2012, the service received a right-of-way application from NordAq to develop the Shadura site. The agency then proceeded with writing an environmental impact statement.

The service considered a number of alternatives for road and pipeline access to the site, including a couple that would've had the road come out of the Swanson River oil field to the east. NordAq objected to these alternatives, saying they posed "financial costs and complications" that could kill the project.

In the end, the Fish and Wildlife Service granted NordAq's favored alternative, with the 4.3-mile access road coming in from the northwest off the Kenai Spur Highway at Captain Cook State Recreation Area. Buried gas lines and a communications cable will parallel the road.

see **SHADURA GAS** *page 20*

GOVERNMENT

Northern resource push

Alaska, Canadian governments probe of options to get stranded oil, gas to market

By GARY PARK
For Petroleum News

The governments of Alaska, Alberta, Northwest Territories and Yukon are making an all-out effort to get some of their prodigious oil and natural gas resources to market.

DAVID RAMSAY

Energy leaders of the four jurisdictions agreed in Anchorage July 16 to explore every means possible to free the stranded resources of the North Slope, Beaufort Sea, Mackenzie Delta and Central Mackenzie Valley.

Having watched the evaporation of their grand plans to ship Arctic natural gas to southern Canada and the Lower 48, they are working on a regional strategy that could see Canadian production shipped to Asia through Valdez, or from Tuktoyaktuk in the NWT.

"These are early days, but we have many options on the table," NWT Industry Minister David Ramsay told Petroleum News. "We will continue our discussions to find the best fit."

He said the participants hope to "meet again sometime soon."

Alberta Energy Minister Ken Hughes said the governments are "pursuing all options ... south, west, east and north."

Ramsay said they include a possible pipeline orig-

see **RESOURCE PUSH** *page 15*

contents

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

Alaska - Mackenzie Rig Report

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 NG1-01, workover	BP
Dreco 1000 UE	16 (SCR/TD)	Prudhoe Bay, rig maintenance	BP
Dreco D2000 Uebd	19 (SCR/TD)	Alpine CD4-292	ConocoPhillips
AC Mobile	25	Prudhoe Bay J-29	BP
OIME 2000	141 (SCR/TD)	Kuparuk 2G-11	ConocoPhillips
Kuukpik	5	Rigged up on Umiat Disp#1 to spud November 2013	Linc Energy Operations Inc.
Nabors Alaska Drilling			
Trans-ocean rig	CDR-1 (CT)	Prudhoe Bay	Stacked
AC Coil Hybrid	CDR-2	Kuparuk 2F-18	ConocoPhillips
Dreco 1000 UE	2-ES (SCR-TD)	Prudhoe Bay	Available
Mid-Continental U36A	3-S	Prudhoe Bay	Available
Oilwell 700 E	4-ES (SCR)	Prudhoe Bay	Available
Dreco 1000 UE	7-ES (SCR/TD)	Kuparuk	ConocoPhillips
Dreco 1000 UE	9-ES (SCR/TD)	Prudhoe Bay	Available
Oilwell 2000 Hercules	14-E (SCR)	Prudhoe Bay	Available
Oilwell 2000 Hercules	16-E (SCR/TD)	Prudhoe Bay	Available
Oilwell 2000	17-E (SCR/TD)	Prudhoe Bay	Stacked
Emsco Electro-hoist-2	18-E (SCR)	Prudhoe Bay	Stacked
Emsco Electro-hoist Varco TDS3	22-E (SCR/TD)	Prudhoe Bay	Stacked
Emsco Electro-hoist Canrig 1050E	27-E (SCR-TD)	Prudhoe Bay	Available
Emsco Electro-hoist	28-E (SCR)	Prudhoe Bay	Stacked
Oilwell 2000	33-E	Prudhoe Bay	Available
Academy AC Electric CANRIG	99AC (AC-TD)	Prudhoe Bay	Available
OIME 2000	245-E (SCR-ACTD)	Oliktok Point	ENI
Nordic Calista Services			
Superior 700 UE	1 (SCR/CTD)	Prudhoe Bay Drill Site F-01B	BP
Superior 700 UE	2 (SCR/CTD)	Prudhoe Bay Well Drill Site Y-33A	BP
Ideco 900	3 (SCR/TD)	Kuparuk Well 30-04	ConocoPhillips
Parker Drilling Arctic Operating Inc.			
NOV ADS-10SD	272	Prudhoe Bay DS 18	BP
NOV ADS-10SD	273	Prudhoe Bay W-51	BP
North Slope - Offshore			
BP			
Top Drive, supersized	Liberty rig	Inactive	BP
Doyon Drilling			
Sky top Brewster NE-12	15 (SCR/TD)	Spy Island SP 36-W5	ENI
Nabors Alaska Drilling			
OIME 1000	19AC (AC-TD)	Oooguruk ODSN-02	Pioneer Natural Resources
Interior Alaska			
Nabors Alaska Drilling			
Academy AC electric CANRIG	105AC (AC-TD)	Nenana Basin	Doyon Ltd.
Cook Inlet Basin – Onshore			
Kenai Land Ventures LLC (All American Oilfield Associates, labor Contract)			
Taylor	Glacier 1	Kenai Loop Drilling Pad #1	Buccaneer Energy Ltd.
All American Oilfield Associates			
IDECO H-37	AAO 111	On the West side for NordAq Energy's Tiger Eye Central Well	NordAq Energy
Aurora Well Services			
Franks 300 Srs. Explorer III	AWS 1	Plans to spud NCU 14 for Aurora Gas this week	Aurora Gas
Doyon Drilling			
TSM 7000	Arctic Fox #1	North Kenai, stacked	Available
Nabors Alaska Drilling			
Continental Emsco E3000	273E	Kenai	Available
Franks	26	Kenai	Stacked
IDECO 2100 E	429E (SCR)	Kenai	Available
Rigmaster 850	129	Kenai	Available
Academy AC electric Heli-Rig	106-E (AC-TD)	Kenai	Available
Cook Inlet Basin – Offshore			
XTO Energy			
National 110	C (TD)	Idle	XTO
Spartan Drilling			
Baker Marine ILC-Skidoff, jack-up		Spartan 151 Upper Cook Inlet KLU#1	Furie
Cook Inlet Energy			
National 1320	35	Osprey Platform RU-1, workover	Cook Inlet Energy
Hilcorp Alaska LLC (Kuukpik Drilling, management contract)			
		Monopod A-3 RD3, workover	Hilcorp Alaska LLC
Mackenzie Rig Status			
Canadian Beaufort Sea			
SDC Drilling Inc.			
SSDC CANMAR Island Rig #2	SDC	Set down at Roland Bay	Available
Central Mackenzie Valley			
Akita			
TSM-7000	37	Racked in Norman Well, NT	Available

The Alaska - Mackenzie Rig Report as of July 18, 2013. Active drilling companies only listed.

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

This rig report was prepared by Marti Reeve

JUDY PATRICK

Baker Hughes North America rotary rig counts*

	June 28	June 21	Year Ago
US	1,759	1,757	1,953
Canada	294	214	296
Gulf	55	57	48

Highest/Lowest

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

*Issued by Baker Hughes since 1944

The Alaska - Mackenzie Rig Report is sponsored by:

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● GOVERNMENT

Wielechowski pushes SB 21 ballot recall

Anchorage Democrat says oil tax change 'giveaway,' bill 'fundamentally flawed'; calls for natural gas focus on big line, Cook Inlet

By STEVE QUINN
For Petroleum News

Sen. Bill Wielechowski is adamant that the new tax regime enacted in Gov. Sean Parnell's Senate Bill 21 is so flawed that the state's voters need to weigh in and get a chance to overturn the legislation.

A referendum he calls "truly grassroots" could be on the ballot in August 2014. For now, the state is reviewing more than 50,000 signatures to see if the referendum can be put to the voters.

Wielechowski sat down with Petroleum News to discuss what he believes are the flaws and strengths of SB 21.

Petroleum News: Critics of SB 21 have called the new regime a giveaway. And that word keeps coming up. Why is this giveaway?

Wielechowski: The biggest concern that I have with the bill — and that many have with the bill — is the fact that every penny of the $5 billion that's being given to the oil industry through the tax cut is for oil that they already promised they were going to produce. The oil companies are required to let (Natural Resources Department) know and (Revenue Department) know what their forecasts are: how much oil they are going to produce and where are they going to produce it. Every penny of this tax cut is for oil the oil companies have already told us they planned to produce under ACES (Alaska's Clear and Equitable Share, the tax regime enacted in 2007). So that's why it's a giveaway. That's one of the biggest fundamental problems that many of us have with this bill. There are some things in SB 21 that we supported, but this was the biggest fundamental problem, in my opinion, of the bill.


SEN. BILL WIELECHOWSKI

Petroleum News: So what things did you support?

Wielechowski: There were provisions for incentives — the gross revenue exclusion in new fields and new producing areas — those are things we had in the Democratic bill. The problem we had with SB 21, it was expanded way beyond what it needed to be. It was expanded again to include oil that was already going to be produced. It was expanded to include oil in the legacy fields where the rates of return according to the Parnell administration experts are over 100 percent. You didn't need to provide gross revenue exclusions in those areas. I didn't support that and I don't support that.

Petroleum News: Was there anything about ACES that you believe was working?

Wielechowski: I think ACES was very successful in increasing the number of companies coming to Alaska. If you look from the time we passed ACES (November 2007) to the present, we increased the number of companies coming to Alaska by 383 percent. The fundamental problem we saw with the old oil structures — PPT and ELF — was that you had very little taxes and yet you didn't have companies increasing investment. In fact for 30 years you had a zero percent tax structure on 15 of the 19 fields under ELF. Yet you had production declining from 2 million barrels per day to 750,000 barrels per day. You had jobs declining. You had investment declining. So it was a failed philosophy. PPT went from a gross structure to a net tax structure, but it didn't fix the problem. Our experts told us the industry was in harvest mode, taking very large profits and investing in other countries around the world, like Libya where you had 95 percent tax rate, like Venezuela where you have a 90-plus percent tax rate, like many other countries around the world. What we said with ACES was how do we fundamentally change the dynamic here? You have an oligopoly on the North Slope and you've had it for decades. So we created a large tax credit, tax deduction system, which has been wildly successful because it's brought in a huge number of new companies. We wanted to encourage new investment, which I would say was wildly successful. You had investment increase to all-time highs every year except for one. It was successful in creating jobs to all-time highs on the North Slope. The investment was not just for operating investment for maintenance, it was also for capital investment. It was successful of course for the state because for years we had very low, if not no tax structure, on the North Slope, and we were practically broke by the end of 2006, so it was successful to the extent that the state got its fair share and we were able to grow our savings to over $17 billion. What we were saying with ACES was what we had going over three decades was not working. It cost us tens, if not hundreds, of billions of dollars in lost revenue. It didn't increase production. It didn't increase jobs. It didn't increase revenue.

Petroleum News: Now you have a new

see **WIELECHOWSKI Q&A** *page 12*

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CORRECTION

Insufficient evidence on sinking

The issue of Petroleum News for the week of July 14 incorrectly reported IHS CERA as concluding that oil sands bitumen blends sink more rapidly than other crudes of similar density. The consulting firm's special report said "there is insufficient evidence to conclude that bitumen blends are more or less prone to sinking than heavy oil of comparable density. To date, practical experiences have been limited, tests have been lab scale and methodologies have been debated. More research is warranted."

● ENVIRONMENT & SAFETY

Judge 'dismayed' over oil spill studies

Federal and state governments report delays in wrapping up research related to unresolved Exxon Valdez 'reopener' demand

By WESLEY LOY
For Petroleum News

A federal judge said he's "dismayed" at the slow progress on studies that could determine whether the state and federal governments try to collect a huge sum of money for the 1989 Exxon Valdez oil spill in Alaska's Prince William Sound.

Seven years ago, in 2006, the governments hit ExxonMobil with a demand for more than $92 million for habitat restoration. The governments say lingering oil remains embedded in Prince William Sound and Gulf of Alaska beaches, and it could be harmful to wildlife.

To date, ExxonMobil hasn't paid the demand, and the governments haven't sued to collect the money.

Lawyers for ExxonMobil previously have said the $92 million demand is invalid, that the oil spill cleanup concluded long ago, and that the company owes nothing more.

The governments made the demand under a 1991 civil settlement that saw Exxon pay $900 million for the oil spill.

The settlement contained a "reopener" clause entitling governments to request up to $100 million extra to address unanticipated injury to habitats or species.

Contracting and other snags

Since making the $92 million reopener demand, the governments say certain studies have been under way to clarify just what sort of actions, if any, might be appropriate to restore the injured habitats.

Government lawyers outlined the status of these studies in a June 28 report to U.S. District Judge H. Russel Holland, who long has presided over Exxon Valdez matters.

The status report indicated the conclusion of a number of studies had been delayed for various reasons.

One study looks at the feasibility of injecting nutrients and oxygen into sediments to speed up the natural breakdown of oil. The field work included visits to 23 beaches to evaluate, from an engineering standpoint, their suitability for bioremediation, the status report said.

A final report on this work was due to the Exxon Valdez Oil Spill Trustee Council by April 15. But the analysis of data from the field work was "delayed significantly due to unforeseen contracting issues," the governments said, and the final report now is due at the end of January 2014.

Other studies have to do with the impacts of oil on harlequin ducks and sea otters. These studies also have been delayed, or are still undergoing analysis or peer review, the status report said.

Once the field studies are complete, the governments will "determine the next steps," taking into consideration the environmental benefit, likely costs and public input.

"The Governments anticipate discussing with Exxon its interest in participating in those next steps, as appropriate, and a possible resolution of the Governments' demand to Exxon under the Reopener," the status report said.

Spilled oil still toxic, activists say

In a brief July 1 order, Judge Holland said he accepted the status report, but added: "The court is dismayed that so few of the projects that the Governments had expected to be completed by now have been completed. The court urges that those who are assisting the Governments in their endeavors be required to complete their work by the revised completion dates."

He directed the governments to submit another status report by March 14, 2014.

Lawyers for ExxonMobil previously have said the $92 million demand is invalid, that the oil spill cleanup concluded long ago, and that the company owes nothing more.

An organization called Public Employees for Environmental Responsibility, or PEER, on July 15 issued a press release calling attention to the latest status report and Holland's order.

"Amazingly, it's been seven years since the governments demanded this payment from Exxon but they have yet to collect a dime," said Rick Steiner, a PEER board member and retired University of Alaska professor who has pushed the court to force Exxon to pay.

Holland has declined to order payment, saying it's up to the governments, not the court, to press a reopener claim.

"The coastal ecosystem injured by the Exxon Valdez spill is still a long way from full recovery," the PEER press release said. "Lingering oil has been degrading at a far slower rate than anticipated and is still affecting natural resources at toxic levels. Several marine species, from herring to otters to orcas, have not yet recovered from the spill." ●

Contact Wesley Loy at wloy@petroleumnews.com

EXPLORATION & PRODUCTION

Radioactive tracers OK'd at Prudhoe plant

The Alaska Oil and Gas Conservation Commission recently approved a request from BP to inject low-level radioactive tracers into a plant that processes crude oil in the Prudhoe Bay field.

The company said it planned to use the tracers in a capacity study at Gathering Center 2, in Prudhoe's western operating area. The plant separates oil, gas and water.

Radioactive tracers are chemical compounds with widespread application in industry, medicine and research.

The study will look at the efficiency of various vessels in GC2 and guide "appropriate upgrades to the facility for increased separation capacity," BP said in a May 14 letter to the commission.

Radioactive tracers are chemical compounds with widespread application in industry, medicine and research.

The tracers can be detected or measured easily by their emissions, and can show the movement of liquids within piping and vessels.

BP told the commission the half-lives of the tracers it planned to use in the GC2 study would be less than two days.

'Exceedingly small' volume

"Radioactive tracer is needed to calculate the residence time of the oil and water phases in the slugcatchers and the water residence time in the skim tanks," the company said.

BP said it considered using alternatives to radioactive tracers, but decided against them.

"A non-radioactive tracer would require frequent sampling, and there is a pos-

see **TRACERS** *page 10*

● EXPLORATION & PRODUCTION

A responsible route to shale development

Experts argue for comprehensive risk management, open communications when addressing concerns around the use of fracking techniques

By ALAN BAILEY
Petroleum News

With concerns about possible impacts including groundwater contamination, excessive water consumption and gas leakages, the shale oil and gas revolution that is upending the North American oil and gas industry has been facing many questions regarding safety and environmental protection.

But ensuring safe shale developments and dealing with the uncertainties inherent in development projects requires a comprehensive risk management approach, two experts told the K&L Gates Alaska Oil and Gas Conference on July 10.

Five issues

David Wochner, a partner with K&L Gates, said that there are typically five major issues facing a shale development, with each issue having the potential to derail a development project: the siting of wells; water supplies for fracking operations; the flow-back and disposal of fracking fluids; air quality; and the disclosure of information about chemicals used in fracking fluids.

> *"It's the surface issues that can really get the juices flowing in opposition."* **—Richard Green, director of innovation in North America, Det Norske Veritas (USA) Inc.**

In the United States the issues surrounding well siting are being worked out on a state-by-state basis, with an emerging consistency regarding requirements such as minimum distances from occupied structures, Wochner said.

But the issue of water withdrawals for fracking operations is huge, despite the water usage actually being lower than that of some other applications such as the irrigation of golf courses, he said. States such as Illinois are implementing regulations requiring companies to submit water withdrawal and management plans, while there is also a question of the extent to which states have policies for the use of non-fresh-water.

Operators are increasingly trying to save water consumption through re-use, Wochner said. Richard Green, director of innovation in North America for Det Norske Veritas (USA) Inc., said that the oil industry is also investigating the potential to substantially reduce the use of chemical additives in areas where water can be recycled. And some companies are interested in the possibility of using materials such as propane, nitrogen or carbon dioxide as alternatives to water in fracking operations, he said.

Fluid disposal

Then there is the question of how to dispose of the fluids that flow back out of a well after fracking, if the fluids are not being recycled. Usually 25 to 30 percent of the injected water re-emerges as flow-back — apparently about 80 percent of these fluids are recycled in operations in the northeastern U.S., Wochner said. Storage and management of the waste fluids are huge issues, with the possibility of having to truck the fluids to storage tanks or pits. In addition to the underground injection of the fluids, other disposal possibilities include evaporation of the fluids in dry regions such as Texas, or the use of brine for salting roads in winter, as in West Virginia, Wochner said.

Issues surrounding air quality include new Environmental Protection Agency rules for green well completions, to minimize the unintended release of natural gas into the atmosphere. Following comments from the industry, the agency is using a phased approach to introducing these regulations, Wochner said.

Chemical additives

The disclosure of information about chemicals added to fracking fluids has been a major issue but was probably overemphasized by companies concerned about divulging trade secrets, Wochner said. States have been implementing regulations for the disclosure of fluid additives. In addition, it is essential that emergency responders have full information about any material they have to deal with. Regulations have provisions for trade secrets, which are also strongly protected under U.S. common law, Wochner said.

Both Wochner and Green emphasized the importance of considering the likelihood as well as the potential impact of issues that might impact a shale project. For example, a federal moratorium on shale development would have a massive impact on the industry but is extremely unlikely to happen, Wochner said. On the other hand, local moratoria, such as the moratorium in the state of New York, do happen but have just a moderate impact on the industry as a whole.

Limitations on water consumption, water treatment and water disposal score relatively high both in terms of likelihood and impact.

Fear of the unknown

Wochner said that, while shale development creates jobs, brings new state and local revenues, and can spawn new sectors in the economy, new shale technologies bring a fear of the unknown.

"Getting citizens comfortable with this 'in your backyard' … is an important step," Wochner said.

And, while North America is in the midst of a shale revolution, this revolution has yet to catch on in other parts of the world, Green said.

"In many parts of the world the reason that things are lagging is because they're still fighting to get a social license to operate," Green said. Det Norske Veritas has developed a code of best practice for shale gas development, driven initially by consultations in Europe over concerns about safety and environmental issues associated with shale development techniques.

Green said that, while companies need to worry about the subsurface impacts of fracking, surface-related issues such as water rights and waste disposal can present some of the biggest challenges.

"It's the surface issues that can really get the juices flowing in opposition," he said.

And, in addition to identifying and managing potential project pitfalls and uncertainties, consistent and truthful communications with the public are a key to success, Green said.

"It's all about transparency," he said. ●

Contact Alan Bailey at abailey@petroleumnews.com

ENVIRONMENT & SAFETY

USCG targeting mid-August for Kulluk report

The U.S. Coast Guard hopes to publish the report from its investigation of the Dec. 31 grounding of the Kulluk, Shell's Arctic floating drilling platform, by Aug. 12, Lt. Cmdr. Dan Buchsbaum, chief of inspections for the Coast Guard's Anchorage sector, told the K&L Gates Alaska Oil and Gas Conference on July 10.

The Coast Guard has been conducting a formal marine casualty inspection of the grounding incident and as part of that investigation held a nine-day hearing in Anchorage at the end of May. The Agency had originally planned to publish the results of its investigation in July.

—ALAN BAILEY

● EXPLORATION & PRODUCTION

New oil sands play going commercial

By GARY PARK
For Petroleum News

Alberta oil sands startup Laricina Energy is positioned for a breakthrough in the previously untapped Grosmont formation, aiming to bring on the first phase of its Saleski project in 2015 at 12,500 barrels per day.

The company has earmarked C$520 million to launch commercial development of a resource estimated to hold 466 million barrels of proved plus probable resources and 4.2 billion barrels of contingent resources.

Laricina Chief Executive Officer Glen Schmidt said his company hopes to introduce more phases over time to reach ultimate output of 280,000 bpd.

Laricina is 60 percent operator of Saleski, with Osum Oil Sands holding the balance. Korea Investment Corp. also has an indirect investment because of its financial role with the two companies.

The partnership has been testing a 1,800 bpd cyclic steam-assisted gravity drainage pilot at the site since 2010.

Schmidt said Alberta government approval to embark on the commercial stage "adds to the recognition of the pilot's demonstrated commercial production."

Four wells drilled

He said four horizontal wells have been drilled in the Grosmont and are "behaving as we expect."

Schmidt said that as Saleski goes through steam-assisted gravity drainage production cycles, Laricina is continuing to validate the design.

"There obviously will be opportunities to continue to optimize further and we have some work ongoing in the pilot to do that, such as the solvent application," he said.

The regulatory approval covers 32 wells, 12 more than are needed to support production.

Although Grosmont is a new production area infrastructure such as natural gas and power lines are already in place.

Schmidt said the partnership will need external financing sources and plans to raise money from the markets.

Public offering expected

Randy Ollenberger, a BMO Capital Markets analyst, said Laricina will likely issue an initial public offering in 2014.

"Technology will play a key role in unlocking the new barrels at Grosmont and some other producers are also lining up to invest in pilot plants," he said in a research note.

Those participants include Shell Canada, Husky Energy, Suncor Energy and Cenovus, all of them operating pilot plants.

see OIL SANDS PLAY page 8

Pengrowth chases oil sands growth

Calgary-based Pengrowth Energy has received final Alberta regulatory approval for the first commercial phase of a thermal oil sands project — a C$590 million plant to initially produce 12,500 barrels per day.

The Lindbergh project is expected to come on stream by late 2014 and ramp up over time to 50,000 bpd.

Pengrowth Chief Executive Officer Derek Evans said that "based on an outstanding pilot performance, we expect the commercial project will be a highly economic, low steam-oil ration, low-decline project that, once at full capacity, will provide the backbone for a long-term, dividend-paying" operation.

The pilot has produced 2,300 to 2,500 bpd over the last two months.

Subject to company and regulatory approvals, Pengrowth plans to start production from the second phase in early 2017 and add a third phase by late 2018.

Unlike most of the thermal-recovery projects in northeastern Alberta, Lindberg is in east-central Alberta near Cold Lake, which offers the advantage of all-season access and close proximity to pipelines.

To help pay for its oil sands expansions, Pengrowth sold assets in Weyburn, Saskatchewan, for C$316 million in March and is targeting an additional C$700 million of dispositions before the end of 2013.

—GARY PARK

PIPELINES & DOWNSTREAM

Chevron denied refinery status

Chevron Canada lost a battle of refineries in its bid to have its Burnaby facility in Port Metro Vancouver declared a "priority destination" for crude shipped on Kinder Morgan's Trans Mountain pipeline from Alberta.

The company filed the application with Canada's National Energy Board 15 months ago, claiming it was unable to access enough crude for the 55,000 barrels per day facility.

The bid was opposed by BP Canada, Tesoro Canada, Phillips 66 Canada and Shell Trading Canada, which have refineries with combined capacity of 590,900 bpd in the Puget Sound area of Washington State and which also access Canadian crude on the Trans Mountain pipelines.

The regulator said, in fact, that Chevron had consistently met its minimum 40,000 bpd rate and concluded that it was up to Chevron to make sure it had enough supply options to remain afloat.

They said that if Chevron gained the designation less crude would be available off Trans Mountain for their refineries, putting them at a competitive disadvantage.

Imperial Oil, which operates a refinery in the Edmonton area, also opposed the application.

If the board had approved the request, Chevron would have been able to receive all 57,000 bpd of the crude it could process without being subject to apportionment on Trans Mountain.

Refineries curtailed

Currently, all five refineries connected to the pipeline system are curtailed on a pro rata basis when nominations exceed the pipeline's capacity.

The NEB said that for Chevron to be rated a priority destination it would have had to prove it was unable to meet, or was at substantial risk of not meeting, its minimum run rate and could not reasonably ensure its long-term viability.

The regulator said, in fact, that Chevron had consistently met its minimum 40,000 bpd rate and concluded that it was up to Chevron to make sure it had enough supply options to remain afloat.

The NEB also said Kinder Morgan has until the end of September to either change its procedures for allocating pipeline space or explain why they are adequate.

Kinder Morgan is also working on plans to expand its Trans Mountain system to 890,000 bpd from 300,000 bpd.

—GARY PARK

GOVERNMENT

BSEE developing new Arctic regulations

The federal Bureau of Safety and Environmental Enforcement, or BSEE, is developing new regulations for offshore oil and gas operations in the Arctic, Mark Fesmire, BSEE's Alaska regional director, told the K&L Gates Alaska Oil and Gas Conference on July 10.

"BSEE is expediting the development of new Arctic standards and regulations," Fesmire said. "The regulations will go through the normal Administrative Procedures Act rule-making process."

In the interests of developing appropriate draft regulations prior to the start of the formal public process, thus making the formal rule making as efficient as possible, BSEE is in the process of holding meetings with various stakeholders, including private organizations, local governments and oil companies, to discuss the agency's proposals. "We're contacting those people and talking to them about these regulations before we start the formal process," Fesmire said.

Fesmire told Petroleum News that BSEE hopes to start the formal rule-making process in December.

People can expect new rules for the Arctic to include requirements for the use of best available and safest technology, Fesmire told conference attendees. And BSEE is taking into account unique aspects of operating in the Arctic, including issues surrounding the securing of a well at the end of the Arctic open water season; the possibility of having to move a rig from a drilling site because of encroaching sea ice or severe weather; and the need to avoid interference with bowhead whale migration and the associated subsistence hunting, Fesmire said. Also, with no deepwater port on the coast of the North Slope, companies will generally have to bring their own logistics capabilities to the Arctic offshore, he said.

BSEE has been recruiting new staff to support its Arctic activities, but budget sequestration in Washington, D.C., has brought the hiring process to a halt at the moment, Fesmire said.

—ALAN BAILEY

● NATURAL GAS

RCA diving into Interior gas case

Asking Fairbanks Natural gas and Interior Alaska Natural Gas Utility to answer questions about existing statute, case law

By ERIC LIDJI
For Petroleum News

With an eye toward resolving the competing applications, state regulators want information from two natural gas distribution utilities looking to serve the Interior.

The Regulatory Commission of Alaska is asking Fairbanks Natural Gas LLC and the Interior Alaska Natural Gas Utility to answer a series of questions designed to help the regulatory body discern how the two applications fit within existing state statutes.

The privately held Fairbanks Natural Gas currently provides service to the urban core of the city of Fairbanks, but is looking to expand to North Pole, Eielson Air Force Base and other less-densely populated sections of the borough. The Interior Alaska Natural Gas Utility is a municipal entity wants a certificate to serve a region similar to that expansion.

The answers the utilities provide to the six questions could have significant implications for plans to expand natural gas distribution across the Fairbanks North Star Borough.

For instance, the RCA wants to know whether the utilities believe their applications are "mutually exclusive" or would "compete to furnish identical utility service."

If the applications are mutually exclusive, the RCA is required to hold a hearing to compare the proposals. If the applications compete to the determent of the public interest, the RCA is allowed to divvy up the service area or take other measures to improve the system for consumers. And while the Interior Alaska Natural Gas Utility would typically be exempt from regulation because it is a governmental entity, state statute waives the exemption when a municipal utility competes directly against a regulated private utility.

Currently, Fairbanks Natural Gas can set its rates relatively at will, but under a recent settlement the utility agreed to voluntarily become rate regulated within the coming year.

Lisankie ponders precedent

While the situation in the Interior is rare in Alaska, there are previous cases where a municipal utility sought to serve a similar area as a certificated utility. In a pair of 1967 decisions — the first involving the City of Anchorage and Chugach Electric Association and the second involving the City of Kenai and Homer Electric Association — the Alaska Supreme Court allowed the municipal utilities to compete against certificated utilities within their municipal boundaries. Today, statutes require municipal utilities to become certificated, but Commissioner Paul Lisankie said the rulings still create uncertainty.

If a municipal utility must prove its credentials through the certification process, he asked, could state regulators later deny the utility the right to provide service simply because a "better quali-

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OIL SANDS PLAY

Shell, which holds 85,000 acres, said in June it has been conducting appraisal and exploration activities, including seismic and drilling, to gain a better understanding of the resource.

Shell also expects to carry out a pilot to test its in-situ upgrading technology and verify hydrocarbon resources.

The primary objective of the pilot is to evaluate different heater well designs to melt the bitumen deposits, directional drilling techniques, deployment methods, drilling rigs and surface support systems for a commercial project, Shell said. ●

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● NATURAL GAS

US LNG exports — where does Alaska fit

Oil and gas conference panel reviews liquefied natural gas market, says many projects — like Alaska's export line — won't go soon

By KRISTEN NELSON
Petroleum News

A proposal to liquefy and export Alaska North Slope natural gas as LNG has advantages and disadvantages over competitors. That was the general consensus of a panel at the K&L Gates Second Annual Alaska Oil and Gas Conference in Anchorage July 10. Panel members included: Steven Sparling, the panel moderator, and David Wochner, both partners in K&L Gates Washington, D.C., office; Christopher Goncalves, director of the Berkeley Research Group's global gas and LNG advisory practice, also based in D.C.; and Larry Persily, federal coordinator in the Office of the Federal Coordinator for Alaska Natural Gas Transportation Projects.

The panel provided a D.C.-perspective on Alaska's efforts to export its North Slope gas as liquefied natural gas.

Alaska, because it isn't connected to the Lower 48 gas distribution system, isn't expected to face concerns about exporting natural gas that could be used domestically, but it will face federal agency approval for the project.

Federal approvals required

That approval comes from two major agencies, Wochner said: The Federal Energy Regulatory Commission, which has jurisdiction over facilities for importing and exporting LNG, and the U.S. Department of Energy, which has authority over the import and export of the gas.

FERC has a "very well-established process," Wochner said, which is similar for environmental reviews to what the agency does for Lower 48 gas pipelines, so the agency has "a robust staff in place" with environmental and hearing experience. Even with an experienced staff it's a lengthy process, taking 18 to 24 months. But because it's a regular process project developers know what to expect from FERC, he said, unlike the Department of Energy which he characterized as "anything but predictable."

"And this is where all of the uncertainty right now here in the U.S. lies,"

see PANEL DISCUSSION page 13

JUDY PATRICK COURTESY OF K&L GATES

Participants in panel on impact of U.S. LNG exports at K&L Gates Second Annual Alaska Oil and Gas Conference in Anchorage July 10, left to right: Steven Sparling, K&L Gates, panel moderator; Larry Persily, federal coordinator in the Office of the Federal Coordinator for Alaska Natural Gas Transportation Projects; Christopher Goncalves, Berkeley Research Group; and David Wochner, K&L Gates.

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RCA PROBE

fied" utility wanted to serve the same area? If not, it would seem the RCA should be allowed to issue two overlapping certificates, Lisankie hypothesized.

And if the RCA were forced to choose between two applicants, wouldn't the municipal utility always win, simply by the benefit of its "privileged" status? "That is not a situation I believe we or the applicants have considered or raised to this point," Lisankie wrote.

The results of the questionnaire will also determine whether the RCA chooses to consolidate the two cases and whether it allows a third natural gas distribution concern eyeing the Interior market, Spectrum Alaska LLC, to intervene in the proceedings.

The utilities are required to respond by July 26.

The RCA is holding a public hearing on the issue on July 30.

Time is of the essence

The distribution system is a crucial component of a much larger program.

Using state funds approved earlier this year, the Alaska Industrial Development and Export Authority is spearheading an effort to build a liquefaction facility on the North Slope, a trucking operation along the Dalton Highway and an expanded distribution grid in the Interior. The goal is to reduce energy costs and improve air quality until a more permanent solution — such as a large-diameter gas pipeline — becomes available.

AIDEA is currently working on the North Slope end of the system, but soon it will need to know which utility (or utilities) would be re-gasifying and delivering the product at the Interior end of the system. The goal is to have the system operational by late 2015. ●

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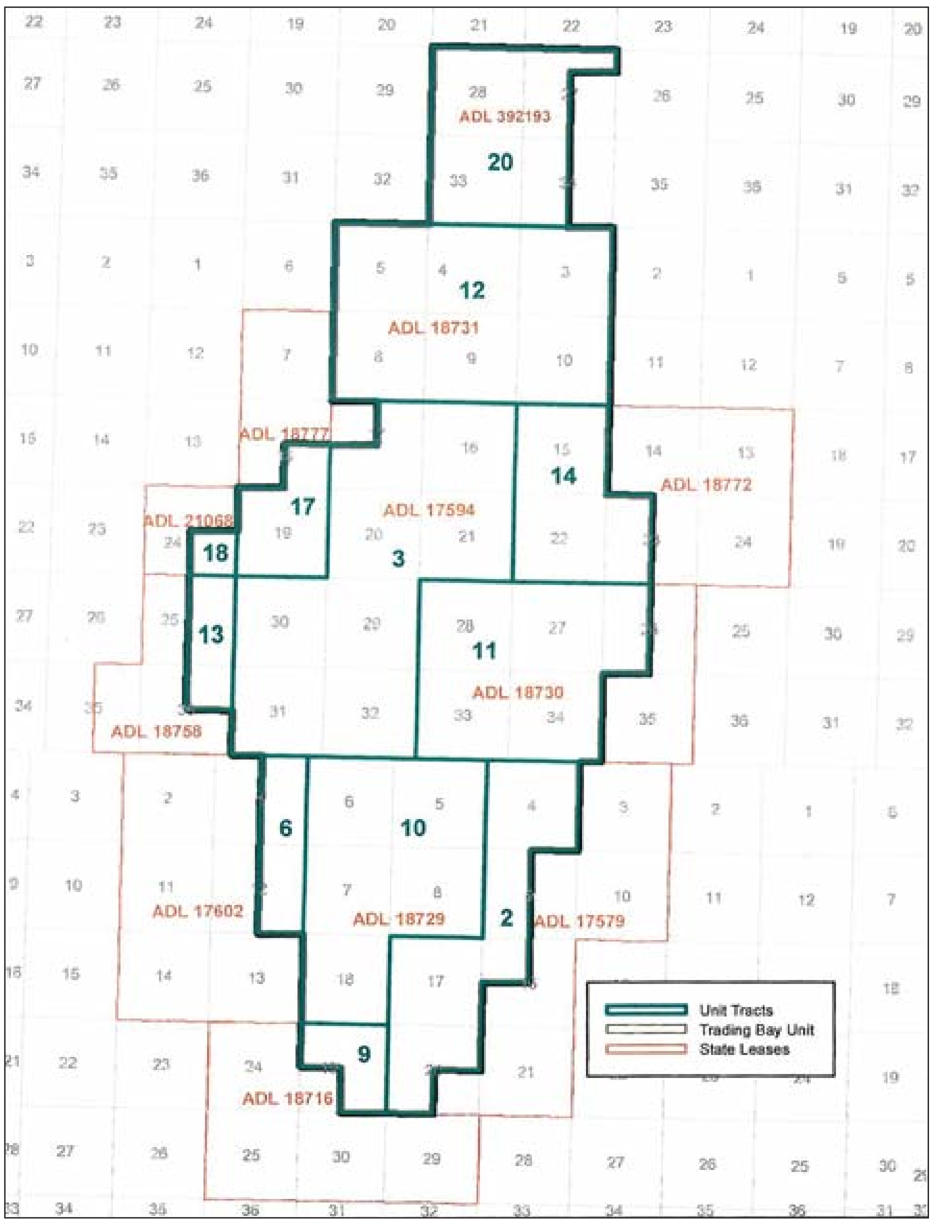

HILCORP ALASKA

● LAND & LEASING

Hilcorp finds Trading Bay gas

Asks Department of Natural Resources to add 2 held-by-production leases to the Trading Bay unit to avoid redundancies

By ERIC LIDJI
For Petroleum News

Hilcorp Alaska LLC is looking to add two leases to the Trading Bay unit to accommodate production from a recent natural gas discovery at the offshore field in the Cook Inlet.

The local subsidiary of the privately held Houston-based company is asking the state to expand the unit on the west side of Cook Inlet to include ADL 18731 and ADL 392193.

The leases cover 5,289 acres and are currently held by production.

Although Trading Bay is historically an oil field, Hilcorp is looking to develop a "newly discovered natural gas deposit" from the Monopod platform, which is located on ADL 18731.

Although Trading Bay is historically an oil field, Hilcorp is looking to develop a "newly discovered natural gas deposit" from the Monopod platform, which is located on ADL 18731. The other lease is adjacent to it. Without expanding the unit to include the leases, Hilcorp will be required to "install duplicative infrastructure and operation systems," according to the company. The duplication could have environmental impacts, and the time needed to install the systems could result in lost royalties to the state, and lost resources too, if Hilcorp has to flare excess gas during the interim, the company said.

Hilcorp is asking the state to expedite its decision.

The state is taking comments on the application through August 12.

The request extends the saga of ADL 18731.

Because Unocal and Marathon both sold their Cook Inlet assets to Hilcorp in recent years, Hilcorp now has full ownership of the Trading Bay unit and the unitized leases.

The Union Oil Company of California and the Ohio Oil Co. acquired the lease in June 1962 and before the end of the summer Marathon Oil Co. acquired the Ohio Oil interest.

In 1965, Unocal and Marathon discovered the Trading Bay field, and the state certified the Trading Bay No. 1A well, located on ADL 18731, as capable of producing in paying quantities. The state included the lease in the Trading Bay unit in February 1967.

The Department of Natural Resources contracted the lease out of the unit in 1972, but the certified status of the Trading Bay No. 1A well protected the lease from expiration.

A sidetrack Unocal drilled from the Monopod platform in 2002 produced from the Trading Bay unit, leading the state to expand the unit in 2003 to include a segment of ADL 18731. The new request would bring the remainder of the lease into the unit.

Because Unocal and Marathon both sold their Cook Inlet assets to Hilcorp in recent years, Hilcorp now has full ownership of the Trading Bay unit and the unitized leases.

The state created ADL 392193 in 2011, segregating it from an existing lease. ●

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TRACERS

sibility the tracer would pass through the system between samples, yielding no data," BP said. "The ability to characterize vessel inefficiencies would be compromised with a non-radioactive tracer."

To allow the use of radioactive tracers, the commission on June 20 amended area injection orders for Prudhoe and related oil pools including Aurora, Borealis, Polaris and Orion.

"After passing through the production facility the radioactive tracers would be entrained in the produced water injection system and injected in enhanced oil recovery and disposal wells," the order for the Prudhoe oil pool said.

The order added: "The volume of radioactive tracer material will be exceedingly small in proportion to the millions of gallons of produced water that GC2 handles on a daily basis."

—WESLEY LOY

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● ENVIRONMENT & SAFETY

Canadian regulators apply squeeze

Conditional approval for Shell Canada's oil sands expansion suggests environmental damage likely to be severe and 'irreversible'

By GARY PARK
For Petroleum News

Shell Canada battled its way through strong opposition from First Nations and environmentalists to gain conditional regulatory approval for expansion of its Jackpine oil sands mine in Alberta to 300,000 barrels per day — only to encounter an unparalleled list of warnings about the project's negative impacts.

The conclusions are also seen as possible pointers to another two controversial regulatory decisions involving the oil sands: Enbridge's Northern Gateway pipeline to export 525,000 barrels per day of crude bitumen to Asia and Athabasca Oil Corp.'s 250,000 bpd Dover project, with Phoenix Holdings (wholly owned by PetroChina) as a 60 percent partner.

The 100,000 bpd addition to Jackpine covers an area of 25,000 acres and will wipe out a large chunk of wetlands, about 85 percent of which are peatlands that can never be reclaimed.

Lack of effective mitigation

A joint review panel of the Alberta Energy Regulator Board and Environment Canada concluded that the addition would "likely have significant adverse environmental effects" on the wetlands, which would harm migratory birds, caribou and other wildlife and wipe out traditional plants used by First Nations for generations.

"There is also a lack of proposed mitigation measures that have been proven to be effective," the JRP said.

In some of the bluntest language ever used in a regulatory report, a 413-page report by the JRP conceded the damage is likely to be severe and "irreversible."

"It is clear that critical issues about oil sands development are increasingly not project specific," the report said.

"Many of the concerns and issues related to this proposal have to do with the pace of development of the mineable oil sands and the capacity of the regional environment to absorb these developments."

Simon Dyer, policy director at the Pembina Institute, an Alberta-based environmental think-tank, said Canada's environmental reputation is being put further at risk as it keeps approving oil sands projects in the absence of adequate rules for global climate change or wetland protection.

"It's the same old stuff," he said.

Shell reviewing conclusions

Shell Canada, which has Chevron and Marathon Oil as partners, said in a statement it was reviewing the JRP conclusions, which include 22 conditions, including conservation offsets.

"Since 2007, we have strived to improve the public's understanding of the project through extensive consultation with people across the region and have submitted over 18,000 pages of information and evidence," it said.

The company said it has bought about 1,800 acres of former cattle pasture in northwestern Alberta to help compensate for the loss of wetland.

A company spokesman, Stephen Doolan, said the regulatory green light does not mean Jackpine will be built.

"Right now our focus is on remaining competitive, economically and environmentally, and that means efficiencies through debottlenecking, or getting the most out of the steel you have in the ground," he said.

The report now goes to the Alberta government and Canada's Environment Minister Peter Kent.

A decision from the federal cabinet on whether to accept, reject or modify the JRP report is expected within four months.

The JRP Jackpine report is seen as the first project review to tackle the cumulative effects of oil sands development, while leaving the larger decisions on environmental concerns and questions about a social license to operate to government lawmakers.

First Nations issues

The legal tussle with First Nations may not be over given the determination shown by the Athabasca Chipewyan First Nation, ACFN, in the northeastern corner of Alberta.

The ACFN made two unsuccessful bids in the Alberta Court of Appeal to block the expansion, then suffered the ultimate setback in the Supreme Court of Canada, which refused to consider whether the community had been adequately consulted.

ACFN Chief Allan Adam said "we have diligently proceeded through legal avenues to have our (constitutional) rights upheld."

The ACFN has hinted it may mount another bid to block the regulatory ruling.

"We will have to decide if we move ahead with different legal strategies to uphold our rights," Adam said.

Rights guaranteed

The Canadian Constitution guarantees aboriginals and First Nations the right to fishing, logging and hunting in their traditional areas and the ACFN has argued that the Jackpine expansion would cause substantial loss of habitat for birds, woodland caribou, bison and elk.

The community also said that in its final stages the project would create a pit lake that could hold 486 billion liters of mine tailings waste, including mercury, lead and arsenic, while contributing 1.18 million metric tons of greenhouse gas emissions to the atmosphere.

Separate pipeline filing

Separately, a joint venture of TransCanada and the Dover partnership has filed a regulatory application for the first major pipeline from new oil sands projects west of the Athabasca River — the largest waterway through the oil sands region — targeting an in-service date of spring 2017.

The C$3 billion Grand Rapids project would consist of two parallel pipelines covering 300 miles and transporting 900,000 bpd of blended bitumen to the Edmonton market and delivering 330,000 bpd of diluents from Edmonton to the oil sands area to help with the pipeline transportation of the viscous bitumen.

In addition, Grand Rapids would include four tank farms with 350,000 barrels of capacity and 150,000 barrels of diluents capacity. ●

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WIELECHOWSKI Q&A

tax regime and an initiative that may find its way on the ballot. Is this referendum realistic?

Wielechowski: I have never seen as much energy and enthusiasm behind a referendum or initiative as I have behind this one. Many times you have referendums driven by certain interest groups. This referendum, it truly was grassroots. It was people coming out of nowhere and having very strong interest in this. There is no special interest driving this. It is truly a grassroots effort with very little money and strong bipartisan support. The chances for success are probably very good. It will no doubt be challenged. There will be a huge amount of money spent by the oil industry to persuade people that it's a bad thing.

Petroleum News: Getting back to the giveaway term for a second, some say it's giving away. Some say it's taking less. Is there a semantics issue here?

Wielechowski: The constitution says you have got to get the maximum benefit for the resource. I have a hard time understanding how we are following the constitution when we are giving $5 billion to the oil industry to produce oil they already said they are going to produce under the ACES tax structure, so you really get nothing for it. By its very nature, it's a giveaway. You have a product that is very valuable that is going to make the oil industry a tremendous amount of money. They have agreed they are going to produce it at a certain rate and you just cut their rate. No business in the world would operate like that. It's a terrible way to run government.

Petroleum News: A ConocoPhillips senior executive told Wall Street during a spring presentation that SB 21 will make a difference. It's one thing to tell the Legislature one thing, but telling Wall Street that could be another altogether. What are your thoughts on that?

Wielechowski: When the oil industry testified six years ago when we passed ACES, there were three different charts produced: a 15 percent decline; a 6 percent decline; a 3 percent decline, and that was the best case scenario under ACES. We expect we will have a 2 or 3 percent decline in the next few years. That's proof by the metrics they set that ACES was working. It's interesting to hear what companies are telling Wall Street because you can go back to statements made by senior executives over the years where they say Alaska offers strong rates of return or they say Alaska offers strong cash margins, or the say they are going to invest hundreds of millions of dollars at very high rates of return.

People can say whatever they want, I suppose. When you look at the company profits, when you look at the rates of return, when you look at the cash margins, there is no denying Alaska is among the most profitable places in the world to do business. You compare the profits per barrel in Alaska — it was $28 to $29 per barrel. Globally it was $12 to $15. The profit per barrel is $28 or $29 versus $3 to $4 in the Lower 48. Executives can say anything, but when you look at the numbers, you can see the industry has made profits of $36 billion since we passed ACES. According to Parnell's own experts, you've got rates of return between 65 and 123 percent range in Alaska compared to 20 to 30 percent in North Dakota, Norway and Canada. The numbers show Alaska is one of the more profitable places in the world. In fact Alaska is more profitable to do business in than it is to do business in North Dakota at $115 or below. That's according to Parnell's experts.

Petroleum News: So would you say Alaska is competitive under ACES?

Wielechowski: Absolutely. We are certainly competitive in the legacy fields. If you look at the rates of return, we were still competitive on the new fields. One of the areas we wanted to focus on were the new fields. That's what the Senate Democrats and the House Democrats said: if you're going to make changes make it for new oil from new fields. That's where we were less competitive. For the newer fields, we could have tweaked that and be more competitive. That's why we proposed legislation to do that.

Petroleum News: The proponents of SB 21 say you need to give it time and let it work. So what will you be looking for over those next several years to gauge the success?

Wielechowski: Again, the problem with SB 21 is it's a fundamentally flawed bill and it's flawed because you have given away $5 billion for oil that they were already going to be produce. Nothing can correct that. That is a flaw which can only be fixed next August when the voters go to the polls. If for no other reason to repeal SB 21, it should be for that reason. You can cut that part out and leave the rest in the bill and have a vastly improved bill. Just for that reason alone, you should overturn that bill. Alaska will never be able to recoup the money it's losing from this sheer giveaway. You can't correct the bill. You don't need to give away $5 billion and get nothing in return. That's just terrible business. There is not a business in the world that would do that. There is not a government in the world that would do that.

Petroleum News: OK, but just the same if this is an issue of giving the bill time to work, what other things would you be looking for if this is about the bill that needs time?

Wielechowski: The very structure of the bill is critically flawed in that you're giving away $5 billion. There are other provisions in the bill — gross revenue exclusions — that I think will have an impact worth watching on the North Slope. Those are things we proposed in the Senate and House Democratic bills. But you can't get around the fact that this is a bill that gives away money for nothing. It will never be a success because you're giving away money for oil that they said would be produced during ACES. We had an amendment that said you don't get the credits for oil you already said you're going to produce. If you got rid of that provision, then come back and ask me the question.

Petroleum News: You've talked about the constitution earlier. Both sides of the argument say it's the constitution that's driving their position. How do you reconcile that?

Wielechowski: The constitution says you've got to get the maximum benefit for the resource. I'm eager to hear how giving away $5 billion for nothing is meeting our constitutional requirements to get the maximum benefit the resource. There is no way this meets the constitutional obligation. It's patently violating the constitution.

Petroleum News: Let's move on to another subject. Gas lines. What kind of progress would you like to see during the remainder of the interim?

Wielechowski: I'd like to see the big line move forward. I'd like to see the big three come together with a plan and let's get moving on it. Let's start the project. We've been waiting a long time. I think the problem with the smaller line has always been volume. You're spending $8 billion to build an 800-mile line and the tariffs are going to be extremely high. When I talk to people in my district and I ask them do you want a small-diameter gas line from the North Slope, many hands in the room go up. When I ask people are you willing to pay double for gas to get it, most hands go down. We've got 19 trillion cubic feet of gas according to the USGS right in our backyard in Cook Inlet. That's enough gas to last 200 years. The idea that you can bring gas from the North Slope and ship it 800 miles cheaper than you can move it 25 miles out of your backyard will be proven to be incorrect, whereas the big line, the economics are much better.

Petroleum News: There are two schools of thought when it comes to negotiating tax terms on the big line. One says wait until the companies have a firm project. The other says the companies need these costs understood before they embark on a multibillion dollar commitment. Where do you fall?

Wielechowski: It's a good question and one that's been kicked around over the years. It's hard for the state to set fiscal terms without having some idea of what the gas line is going to look like and what sort of fiscal terms the industry is going to need. I would like to see what the industry proposes and what their cost structure is going to be. If you set fiscal terms first and the industry comes in and says that's not enough, well you don't have the numbers from the industry to know whether it's enough or not enough. It would be pre-

see WIELECHOWSKI Q&A page 14

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PANEL DISCUSSION

Wochner said.

Other than the Kenai LNG facility, the U.S. has not been an LNG exporter — in fact the Lower 48 was for decades short of natural gas, he said.

With the natural gas surplus in the Lower 48 the Department of Energy has 20 applications pending for export. While a license is automatic for countries with which the U.S. has a Free Trade Agreement, the only big importer among those 19 nations is South Korea, and Wochner described the DOE process for exports to other countries as "robust" with logistics complicated by the very small staff, four to five, in DOE's Office of Fossil Energy which handles import-export licenses.

He said that office went from an office which occasionally got an application for import "to an agency that is at the forefront of a major political debate in Washington right now. They don't have the staff to be able to handle that," Wochner said.

The result is a holding pattern, he said, with one license issued a couple of months ago, although "the hope is that they're going to begin to move through these fairly quickly."

The competition

Persily described the competition — countries that want to get into the LNG export business.

Last year there were 16 countries exporting LNG and "half again as many" that want to get into the business in the next decade, he said.

Persily said Alaskans tell him they are concerned about the competition, but he said those competitors also have challenges.

Among existing producers, for example, Egypt is already running short of gas; Yemen has political problems; Norway has had technical issues; and Angola, which just came on line, was 18 months behind schedule.

There is space in the market, Persily said: Papua New Guinea — coming on line soon — and Australia, with seven projects under construction, have most of their LNG already sold.

"They're not our competitors as we look ahead to the 2020s and beyond," Persily said. While Russia, the Lower 48 and British Columbia are all working to get into the market (or to get more gas into the market in Russia's case), most of those projects won't be built in the next decade, he said: "The world just doesn't need that much LNG."

So who will get into the market?

Persily said "the winners are going to be the ones where the project developers can get together with government and de-risk the project so that they can sell gas at a competitive price and win customers." Alaska isn't out of the running, he said.

The market of the future

The impact of exports on the domestic natural gas price has been a concern, but Goncalves said "so far we haven't seen that it's slowing any permits down," though it may become more of an issue with the next wave of export terminals.

Even if the Department of Energy is comfortable with the price impact, there are the issues of whether prices are sustainable and global impacts, and whether the banks will "take the risk on multibillion-dollar investments."

The price spread between North American traded hub prices "primarily driven by abundant — I won't say cheap — but economic, affordable shale gas production" and Asian LNG prices makes export LNG projects attractive, Goncalves said. He said shale gas production represents more than 35 percent of Lower 48 production and will represent 50 to 60 percent within a few years.

The price spread relates to the fact that in most places, particularly Asia, LNG is indexed to oil, and the focus is on chasing those high LNG prices, in the $17 to $18 range, compared to the U.S. hub-traded price of about $4.

Is that spread sustainable?

It's a "short-term phenomenon — it's really only been a factor for the last several years," he said.

There wasn't much of a spread as recently as 2006 but with more "tightening of the market" following the Fukushima nuclear disaster in Japan the spread has grown.

The current spread comes from two factors, Goncalves said: tightening of the LNG market and the Lower 48 production boom.

And while U.S. concern has been about exports driving up domestic prices, Goncalves said work done by his firm doesn't find any major impact on U.S. prices over the next 10 to 15 years from LNG exports. The impact is expected to be 90 cents to a dollar, he said, which isn't "major insofar as most of the people who are thinking about burning more gas for power plants, for industrial, petrochemical facilities or transportation infrastructure, shipping, rail, LNG trucking and so forth."

And as shale production catches up with an expected level of exports the domestic price impact of exports is expected to drop to 40 to 50 cents.

The price angle which hasn't received much attention is the possible impact of increasing U.S. production on the Asian or European prices for natural gas, he said.

Then there is the impact of U.S. exports on projects worldwide.

Looking at proposed export projects "terminal by terminal, project by project," Goncalves said "on balance about half" of the proposed projects out of Australia and some from East Africa "could be impacted or delayed by the North American supply."

Which projects will go forward?

He said it will be "the projects that are the best designed, that have the critical path variables put in place sooner, and have good economics, supply chain logistical solutions to offer the customers that are going to go forward faster" while other projects won't go away, but will "keep their powder dry for another day." ●

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NATURAL GAS

India close to deal for 10 percent of Pacific Northwest LNG venture

India is on the verge of making its entry into Canada's LNG industry, with two of its state-owned companies expected to pay C$1 billion for a 10 percent stake in the Pacific NorthWest LNG venture controlled by Malaysia's Petronas.

After years of hints, speculation and expressions of interest, Indian Oil Corp. and Petronet LNG are aiming to conclude a deal towards the end of 2013, sources in the company said.

Pacific NorthWest has already signed on Japan Petroleum Exploration as a 10 percent partner for an undisclosed amount. That transaction will give Japex a role in shale gas assets in northeastern British Columbia and the liquefaction plant to be built at Port Edward, near Prince Rupert on the northern B.C. coast.

Export starting in 2019

So far, Pacific NorthWest has a Canadian National Energy Board permit to export 19.68 million metric tons of LNG a year starting in 2019 and has three international contractors working on the final engineering design.

The Canadian Environmental Assessment Agency has also issued guidelines for public hearings and Pacific NorthWest intends to submit its regulatory application by late 2013.

Pacific NorthWest President Greg Kist said in June that the company's doors were open to more partners in the $11 billion project.

He said Asia is "our target and clearly Canadian LNG companies have an advantage of reaching out to that market due to shorter sailing times."

"Historically, LNG producers have favored an oil-indexed pricing like JCC (Japan crude cocktail) but we will establish an acceptable pricing structure as part of negotiations with offtake customers," he said.

China ruled out as partner

Industry sources have ruled out any prospect of Pacific NorthWest selling a stake to Chinese companies if the deal with India falls through because of China's extensive involvement in the global LNG sector.

Kazakhstan earlier in July blocked India's plan to buy ConocoPhillips' stake in the giant Kashgan oil field for $5 billion, with sources predicting China will win the same stake for up to $5.4 billion.

Banking sources say Indian Oil will choose an investment bank advisor soon and expects to make an early announcement on a "long-term attractive offtake" sales contract for Pacific NorthWest.

—GARY PARK

● LAND & LEASING

Reform coming on how state manages land

Proposed regulations would let DNR authorize oil and gas exploration and development generally over large geographical areas

By WESLEY LOY
For Petroleum News

The Alaska Department of Natural Resources is proposing new regulations that could revolutionize exploration and development approvals on state land.

The regulations spring from enabling legislation (House Bill 129) state lawmakers passed in April.

Gov. Sean Parnell offered the legislation as part of his efforts to reform permitting and quickly boost Alaska's oil and gas production.

The new law allows DNR to "review and authorize oil and gas exploration or development across a geographical area rather than by individual project," says a four-page explanatory letter posted online at http://tinyurl.com/pkjo7ls.

Fewer steps

Within an area authorized for exploration or development, an oil and gas lessee still would have to submit a plan of operations for DNR approval before work begins, the explainer says.

If the plan complies with certain terms and conditions, DNR may approve such plans "without a separate public notice."

The Parnell administration says the bill will cut out "repetitive" steps in the permitting process, such as some of the public notice and comment periods associated with pushing a project through the seismic, exploratory drilling and development phases.

Some industry players endorsed the legislation, saying it would provide relief from the current "inefficient and cumbersome" permitting process.

But critics, including environmentalists, said allowing DNR to establish "general conditions" for exploration and development would short-circuit public review of specific project plans.

Size limits specified

The lands DNR could approve for exploration and development would be within previously offered oil and gas lease sale areas.

The proposed regulations include limits on the size of these areas, though they still could be very large.

"A geographical area for exploration will not exceed 35 percent of a lease sale area," the explainer says. "For the North Slope Areawide lease sale area, that means a single geographical area for exploration will not exceed 1.785 million acres. A geographical area for development will not exceed 300,000 acres. For comparison, the Prudhoe Bay Unit on the North Slope is about 255,000 acres."

DNR would exclude land adjacent to incorporated communities, such as Nuiqsut on the North Slope and Homer on the Kenai Peninsula, as well as unincorporated communities with a population of more than 200 people.

The proposed regulations spell out the criteria and information DNR will consider when authorizing exploration or development in a geographical area. The administration says people will have a chance for input at the front-end of the process.

An exploration and development authorization could last up to 10 years.

"Under the new law, the DNR and the public can look holistically at a broader geographical area when evaluating how oil and gas exploration or development should occur on state land," the explainer says. "Through this process, the DNR can minimize adverse effects on state land and resources, ensure the state is developing its resources by making them available for maximum use consistent with the public interest, and provide an opportunity for the public to comprehensively review oil and gas activities within a geographical area. For the lessee, a geographical area approval also provides certainty about conditions under which it can explore or develop in that area. And when approving exploration or development for a geographical area, the DNR will still be able to safeguard environmental, subsistence, community, recreational, and historical concerns through special stipulations and conditions."

The new law does not cover the transportation, or pipeline, phase of oil and gas development. Transportation will continue to be evaluated under existing laws and regulations, the explainer says.

The state has set an Aug. 19 deadline for people to comment on the proposed regulations. ●

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WIELECHOWSKI Q&A

mature to set fiscal terms on gas until you have a pretty firm understanding on the costs and economics are going to look like on the big line.

Petroleum News: On to the Arctic. It's been discussed a lot during the interim. What do you believe the state's role should be, whether it's ANWR or offshore?

Wielechowski: I think the state needs to take an aggressive role in responsible resource development in the Arctic. There's an enormous amount of oil and gas onshore and offshore. The state absolutely needs to lead the charge on that. The federal government has shown very little inclination in the Arctic for whatever reason. I'm glad the state is taking a more aggressive role on that. That's important to our future; it's important to our country's future. It's the next Gold Rush in my opinion. You're going to see open shipping lanes that will dynamically change the way trade is done, not just in the Arctic but across countries. There is tremendous opportunity there. Now is the time that we need very strong leadership and assert our rights over the oil and gas that's there and over the resources in the Arctic. ●

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NATURAL GAS

Homer-area hospital moving to gas

After decades of waiting, Homer has gas.

The South Peninsula Hospital is hosting a "valve-turning ceremony" on July 25 to celebrate becoming the first public building in the city to convert to natural gas.

The rest of the region is close behind.

As of July 8, Enstar Natural Gas Co. contractors were constructing the Homer trunk line and expected to connect the line from Anchor Point to Homer High School within two weeks. Additional contractors are working on the distribution system within Homer.

The work to extend the line to Kachemak City should be completed imminently, at which point crews plan to begin installing service lines through the local project area.

While the majority of the Southcentral region already uses natural gas, the southern tip of the Kenai Peninsula remained on diesel fuel for decades because of the lack of transmission infrastructure. The state recently helped pay for a trunk line to Homer and the remainder of the project is being funded by a surcharge added to local utility bills.

—ERIC LIDJI

GOVERNMENT

9th Circuit rejects Greenpeace request

The U.S. Court of Appeals for the 9th Circuit has rejected a request by Greenpeace that the entire court should rehear the decision in March by a panel of three 9th Circuit judges to uphold an injunction barring Greenpeace from interfering with Shell's Arctic offshore drilling operations. After the federal District Court in Alaska imposed the injunction on Greenpeace in May 2012, the environmental activist organization appealed the District Court decision to the 9th Circuit.

But the 9th Circuit judges have been far from unanimous in their views of the injunction. The March decision upholding the injunction was a majority verdict, with one judge on the panel expressing a dissenting view. And the rehearing request, which had to be considered by all eligible 9th Circuit judges, also resulted in a majority decision, with six judges disagreeing with the rejection of the request.

Apparently Greenpeace U.S.A. is a completely separate legal entity from other Greenpeace organizations, with each organization licensing the Greenpeace name but acting independently.

The legal contention over the Greenpeace injunction revolves around the fact that, while Shell had cited actions by Greenpeace organizations around the world as evidence that Greenpeace intended harm to the company's Arctic activities, the injunction was against Greenpeace U.S.A., an entity that, while verbally supporting actions taken by other Greenpeace organization, had not itself participated in those actions.

Separate entity

Apparently Greenpeace U.S.A. is a completely separate legal entity from other Greenpeace organizations, with each organization licensing the Greenpeace name but acting independently. Greenpeace had argued — and some of the judges had agreed — that a court could not impose an injunction on Greenpeace U.S.A. based on the actions of other entities over which it had no control.

"In doing so, the decision disregards corporate norms of limited liability and relies on a guilt-by-association model that offends justice," the dissenting judges wrote. The dissenting judges also said that penalizing Greenpeace U.S.A. for statements endorsing the actions of other Greenpeace organizations likely infringed Greenpeace U.S.A.'s rights to free speech under the U.S. constitution.

Meantime in London six Greenpeace protesters were arrested for trespass on July 11 after climbing the Shard, Europe's tallest building, in protest at Shell's plans for drilling in the Arctic. According to a report in the Guardian newspaper three Shell office buildings, including the company's London headquarters, are in line of sight of the top of the Shard.

—ALAN BAILEY

continued from page 1

RESOURCE PUSH

inating in the Alberta oil sands, picking up crude from the NWT's Central Mackenzie Valley and Beaufort Sea, then swinging across the northern Yukon to connect with the Trans Alaska Pipeline System to Valdez, opening tanker routes to Asia.

Also being studied are possible LNG exports out of Alaska, drawing on 6 trillion cubic feet of gas reserves in the NWT's Mackenzie Delta and more than 30 tcf on Alaska's North Slope, both losing out on plans to build pipelines to southern markets after being overwhelmed by the development of shale gas.

As well, Ramsay said the NWT and Alberta are studying the feasibility of a pipeline along the Mackenzie River Valley to Tuktoyaktuk on the Beaufort, with shipments reaching Asia through the Bering Strait.

He said the NWT favors a northern pipeline over a rail link from Alberta to Alaska because it would provide an outlet for the NWT's prospective oil fields.

Hughes said a study of the Tuktoyaktuk plan is nearly complete and an assessment of a pipeline to Alaska is due to be finished by 2014.

Exploration success key

To augment the NWT case for pipelines, the government is counting on early oil and natural gas exploration success in two key areas — the Devonian Canol and the Beaufort, Ramsay said.

Those two plays have a combined work commitments of more than C$2 billion through federal exploration licenses.

Husky Energy, Shell Canada, ConocoPhillips Canada and MGM Energy are in advanced exploration stages in the Devonian Canol and Ramsay said he believes a partnership of Imperial Oil, ExxonMobil and BP is "ready to answer the call. ... We've got a big spend coming there."

He said the companies "don't want to say specifically at this point when they have in mind," but he anticipates announcements within a year.

Ramsay said his meetings in recent weeks with industry leaders in Calgary and Houston "have been positive."

Changed 'mindset'

He said the NWT government's optimism is further strengthened by a changed "mindset" among northern aboriginal leaders.

They are "tired of seeing unemployment rates of 30 percent to 40 percent in their communities" and are open to negotiating equity stakes in major projects along the lines of a deal they have in place for a possible one-third ownership position in the

Also being studied are possible LNG exports out of Alaska, drawing on 6 trillion cubic feet of gas reserves in the NWT's Mackenzie Delta and more than 30 tcf on Alaska's North Slope, both losing out on plans to build pipelines to southern markets after being overwhelmed by the development of shale gas.

Mackenzie Gas Project pipeline, Ramsay said.

He said a significant step forward is scheduled for April 2014 when control over resource development is transferred from the Canadian government to the NWT, meaning the petroleum industry will have to deal with only one government.

Although sensitivities over crude-by-rail plans are high, Hughes did not rule out a proposal by Vancouver-based G Seven Generations, which has strong ties with Canadian First Nations, to build a rail line from the oil sands to connect with the trans-Alaska oil pipeline.

He did not believe the disaster at Lac-Megantic in Quebec would stop the increasing use of rail to carry crude, although safety precautions should be ramped up.

"The Quebec tragedy reminds us that if we're able to handle the immense amounts of oil we see being developed we'll have to up our game in all aspects," Hughes said.

Alaska officials were not available to comment on the rail idea, but State Rep. Bob Herron, Democrat of Bethel, told Platts Oilgram News the rail option "will get a chilly reception here after the Quebec disaster."

Representatives of G Seven Generations have made contacts in Alaska in recent months and have spoken of a system capable of hauling 1 million barrels per day, but industry sources have argued that number is unrealistic. ●

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Oil Patch Bits

Vigor Industrial, community college, opened center


COURTESY VIGOR INDUSTRIAL

Vigor Industrial said that it has partnered with South Seattle Community College launching an industrial training center at the shipyard on Harbor Island. The Harbor Island Training Center, which opened with a ribbon cutting ceremony June 7, will provide students with the industrial skills they need to get family-wage jobs at the region's industrial manufacturers. Classes began July 1.

"There's a disconnect between industry and a lot of talented, hardworking people in this country," explained Sue Haley, Vigor's senior vice president of human resources. "People want to work and industry needs a highly skilled workforce. However, Vigor and other manufacturers can't find enough workers with the right skills to fill good-paying jobs. This training center will bridge that disconnect by providing motivated local people with critical industrial skills."

Partnering with South Seattle was a natural fit, she said, with Vigor providing the location, equipment and a real-world industrial workplace, and South Seattle Community College's welding and manufacturing programs bringing their long expertise in skills training and instruction. The center is already garnering wider community support, including a partnership with the United Association of Plumbers and Pipefitters and Local 32, which donated welding machines and will provide additional training options.

The center is located on-site at the shipyard, and includes a computer lab, classroom space and an industrial training floor with weld-booths and industrial machining equipment. The shipyard location will also allow students to experience how the facility works and learn from veteran workers. For more information visit www.southseattle.edu/harbor-island-training-center.

GCI announces launch of new business website

General Communication Inc. announced the launch of a new business website July 15, www.gci.com/business, now offering customers more solutions, more support, and more expertise.

"The new website was designed to be engaging, dynamic and user-friendly while featuring smart technology solutions for Alaskan businesses," said Rochelle Marshall, director of commercial marketing & sales operations. "We're excited to provide our customers with access to relevant content for a wide range of sectors including small business to enter-

see OIL PATCH BITS page 18

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OIL PATCH BITS

prise."

The site includes extensive product information to help customers understand GCI's complete range of business solutions. Key features offer users the ability to: read customer case studies from businesses like Jack White Real Estate, CIRI Alaska Tourism and Associated General Contractors, to name just a few; watch videos; take a tour of GCI's state-of the-art Data Center; learn about industry specific technology from government and resource development to healthcare and tourism; find solutions based on business size and budget from small business to Fortune 100 companies.

Created with user experience firmly in mind, the website is optimized for compatibility with today's browsers and mobile devices.

14th annual Calista Golf Classic another big success

Calista Heritage Foundation, a 501(c)(3) nonprofit, announced July 10 that $252,000 in contributions was received at the 14th Annual Calista Golf Classic. Held June 19 at Moose Run Golf Course, the event to raise scholarship funds was hosted by Ariel Tweto and Stephen Qacung Blanchett.


COURTESY CALISTA CORP.

"Since 2003 the scholarships awarded each year has increased," said CHF President/CEO Rea Bavilla. "This remarkable achievement is only possible due to the generous participation of businesses and organizations. We are extremely grateful as hundreds of students have earned and continue to earn pilot certification, bachelor's, master's and doctorate degrees, vocational training and more."

In 2012, CHF awarded $460,000 in scholarships and, most recently, $177,000 in scholarships for the spring 2013 semester. Since the scholarship program was formally created in 1994, more than $3.2 million in scholarships have been awarded with $1.2 million of that total awarded since 2010.

More than 1,500 students have benefited from this program. In 2012 the top five schools scholarship recipients attended were University of Alaska Anchorage, UA Fairbanks, Alaska Career College, UA Fairbanks-Kuskokwim Campus and Bethel's Yuut Yaqungviat flight school.

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

EXPLORATION & PRODUCTION

AOGCC to revisit 1995 NGL-MI decision

The Alaska Oil and Gas Conservation Commission said July 10 that it "is considering whether changes in circumstances occurring since Conservation Order 360 ... was issued in 1995 warrant revision of CO 360" and has scheduled a public hearing on the issue for Sept. 19.

The commission said it would consider, among other issues: "The continuing viability of the findings and conclusions contained in CO 360" and any affect an annual average miscible injectant volume less than 600 million cubic feet per day will have on ultimate recover from the Prudhoe Bay oil pool.

The issues addressed in CO 360 arose because the owners at Prudhoe Bay — then primarily ARCO, BP and Exxon — held different proportions of the gas cap and oil rim at Prudhoe. Those holding more natural gas (ARCO, Exxon) benefitted more when natural gas was extracted and sold down the trans-Alaska oil pipeline as natural gas liquids, while those holding more crude oil (BP) benefitted more when the natural gas was made into miscible injectant and used for enhanced oil recovery.

ARCO and BP both testified that levels of miscible injectant, MI, and natural gas liquids, NGL, production were causing waste to occur at Prudhoe. BP told the commission that 670-700 million standard cubic feet per day of MI needed to be injected in the reservoir to recover additional oil, while ARCO said that anything less than maximum blending of salable NGLs constituted physical waste.

In its 20-page order, issued in August 1995, the commission noted that lack of alignment between gas cap and oil rim ownership. When the Prudhoe Bay owners unitized the field in 1977 they created two participating areas: the gas cap and the oil rim, with production allocated by participating area ownership and the participating areas to be developed from common facilities.

The commission said Prudhoe was the only oil pool in Alaska unitized with disparate equities between the oil rim and gas cap, and said none of the parties identified any other unitized reservoir in the United States with disparate equity interests

see **DECISION REVISITED** *page 20*

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COST POOLING

The new agreement for cost pooling will only apply to the three remaining owners: BP, ConocoPhillips and ExxonMobil. The official pipeline owners are in fact wholly owned affiliates of these oil companies — the affiliates charge oil shippers fees for transporting oil through the pipeline and pay a share of the costs of pipeline operation. Under the new cost pooling agreement, the costs will be distributed between the affiliate owners in proportion to the volume of oil that each owner ships. The costs to be pooled consist of "non-variable" operating expenses, pipeline property taxes, depreciation and interest payments. Variable operating expenses excluded from the pooling include items such as the cost of fuel used to pump oil through the line — apparently these costs are already allocated back to the owners on the basis of volumes of oil shipped.

Longstanding disputes

The concept of cost pooling for TAPS goes back many years and relates to longstanding disputes over the shipping rates that the pipeline owners charge.

When the pipeline started up in 1977 it operated under a rather unusual arrangement in which each pipeline owner's portion of the line was viewed in effect as a separate pipeline, with the owners competing with each other for shipping business and with each owner free to set its own rate for pipeline use. But, as a single pipeline, the line had to be managed on behalf of the owner companies by a single, jointly owned operating company called Alyeska Pipeline Service Co. Under the original pipeline operating agreement, total pipeline operating costs incurred by Alyeska were allocated back to the owner companies in proportion to each owner's percentage ownership of the line.

But, given the huge amounts of money in oil company profits and state oil revenues at stake in TAPS shipping fees, the setting of rates for oil shipments on the line was disputed as soon as oil started flowing from the North Slope, with the owners being accused of setting rates that were too high.

In 1985 relative peace was achieved by a settlement involving what was referred to as the "TAPS Settlement Methodology," or TSM. Under TSM, an initial attempt at pipeline cost pooling across the pipeline owners, a formula involving total pipeline costs and total pipeline throughput determined a maximum rate that pipeline owners could charge for shipping oil. The owners were allowed to set their own rates, provided those rates did not exceed the TSM maximum.

TSM started to fall apart in the early 2000s when the Regulatory Commission of Alaska, the agency that regulates TAPS oil transportation to destinations within Alaska, issued an order, saying that the rates set under TSM were unfair and requiring rates for oil shipped in Alaska to be lowered. In 2005 and 2006 several parties started disputing the rates charged for interstate oil transportation. And in a 2008 order FERC said that TAPS needed to move to a system of uniform rates for all pipeline owners. With all owners basing their rates on essentially identical total pipeline costs, there was no justification for each owner to assess a different rate, FERC said.

Meantime, disputed rates were suspended, with the possibility of refunds to shippers should these rates subsequently be determined to be too high.

But the establishment of a uniform rate requires an agreement over exactly what costs can be recovered from the rate, how those costs are calculated and the basis under which the costs are allocated between the pipeline owners. These considerations led to negotiations over cost pooling arrangements, the result of which is the settlement that FERC has now announced, with fairness in pipeline cost allocation under a uniform rate driving a need to allocate the costs by oil throughput rather than by percentage pipeline ownership.

The settlement over cost pooling does not resolve another major bone of contention, the question of the extent to which the cost of a major TAPS upgrade called strategic reconfiguration can be recovered from TAPS shipping rates. That dispute is the subject of a major investigation still being conducted by FERC and the Regulatory Commission of Alaska.

—ALAN BAILEY

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BUCCANEER MOVES

eight oil zones, in the Tyonek formation.

The well also found oil in the Starichkof and Hemlock formations, where previous Cosmopolitan wells discovered hydrocarbons. Cosmo No. 1 found 43 feet of indicated oil pay in the Starichkof and 149 feet of indicated oil pay in the Hemlock, according to the company. "Not all of the zones intersected will be flow tested," Buccaneer said.

Buccaneer is the operator of the Cosmopolitan prospect and holds a 25 percent working interest in the leases there, with BlueCrest Energy Inc. holding the majority stake.

The prospect is in the southern Kenai Peninsula, off the coast of Anchor Point.

Fourth attempt

Cosmopolitan is a legacy discovery left undeveloped because of geology and economics.

Pennzoil discovered the prospect in 1967 with the Starichkof State No. 1 and the Starichkof State Unit No. 1, but the results did not justify development at the time.

ConocoPhillips formed the Cosmopolitan unit in 2001. The following year it drilled the Hansen No. 1 well up dip of Starichkof State No. 1, encountering oil in the Starichkof and Hemlock intervals. ConocoPhillips drilled the Hansen 1A sidetrack in 2003, and a 50-day flow test averaged 550 barrels per day of oil. The company shot a 3-D seismic survey over the unit in 2005, but also ultimately chose not to development the prospect.

Pioneer Natural Resources Alaska subsequently acquired Cosmopolitan. In 2007, the company drilled Hansen 1A-L1, a lateral from the Hansen 1A wellbore targeting the upper Starichkof interval. Pioneer re-entered and flow tested the lateral in early 2010.

In a plan of operations around that time, Pioneer described the reservoir as being "lower quality than most other producing oil fields of the Upper Cook Inlet." Still the company launched a unique pilot project to truck crude oil from Cosmopolitan flow tests to the Tesoro refinery in Nikiski. The field produced 33,504 barrels of oil and 119,006 thousand cubic feet of gas, according to Alaska Oil and Gas Conservation Commission figures.

Even though it proposed plans to expand production, Pioneer went the way of Pennzoil and ConocoPhillips in early 2011, saying, "subsequent flow test results and engineering studies indicated that the resource potential was not as large as originally estimated."

The departure split the unit in two. Much of the acreage returned to the state to be offered up in a special lease sale, but Pioneer sold two leases to Buccaneer and BlueCrest.

Cosmo No. 1 is the first well drilled in Alaska using the Endeavour jack-up rig. Buccaneer owns the rig through its joint venture Kenai Offshore Drilling LLC. The Alaska Industrial Development and Export Authority helped the joint venture purchase the jack-up rig.

Buccaneer believes the rig will improve the economics of Cosmopolitan by keeping the company from having to drill all its wells from an onshore pad, the company has said.

The Endeavour rig will move next to the Buccaneer-operated Southern Cross unit.

—ERIC LIDJI

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GAS CONTRACT

Chugach Electric, which runs from the beginning of 2015 to early 2018, would appear to confirm that more optimistic view of the gas supply situation.

Price-cap pricing

According to a July 12 tariff advice filed with the Regulatory Commission of Alaska by Chugach Electric, the utility anticipates purchasing about 17.7 billion cubic feet of gas from Hilcorp during the term of the purchase agreement, with pricing following price caps specified under a consent decree agreed between Hilcorp and the State of Alaska to address anti-trust concerns following Hilcorp's takeover of both Chevron's and Marathon Oil's Cook Inlet gas fields.

The price for base gas — the relatively uniform volumes of gas purchased by Chugach Electric on a routine basis — will range from $7.13 per thousand cubic feet in 2015 to $8.03 per thousand cubic feet in 2018. There are higher prices for "swing load gas," used to meet high winter demand, and for any extra emergency gas supplies. However, Chugach Electric says that it anticipates meeting its seasonal swings in gas usage by storing gas in the Cook Inlet Natural Gas Storage Alaska facility on the Kenai Peninsula during the summer and retrieving the excess summer gas during the winter.

Under the new supply contract Chugach Electric will purchase about 2.43 billion cubic feet of gas in 2015, 5.22 billion cubic feet in 2016, 7.98 billion cubic feet in 2017 and 2.01 billion cubic feet in 2018.

Flexibility

However, the contract does accommodate some flexibility in the volumes of gas purchased at the base rate by allowing Chugach Electric to adjust the base volume up or down 5 percent annually and up or down 3 percent monthly. The gas prices cover the basic production taxes and royalties that Hilcorp pays for gas production but do not cover the cost of transporting the purchased gas around the Cook Inlet gas pipeline system.

Chugach Electric has an existing gas supply agreement with ConocoPhillips and another agreement, previously with Marathon but taken over by Hilcorp. Those two contracts cover Chugach Electric's gas supply needs until the end of 2014, after which the new gas supply agreement with Hilcorp will come into play. The old Marathon contract expires at the end of 2014, with the ConocoPhillips contract continuing until the end of 2016 but only meeting some of Chugach Electric's needs. After the end of 2016 the new Hilcorp contract would be Chugach Electric's sole source of gas, unless the utility chooses to take less gas than it needs by using the contract's flexible terms.

Phil Steyer, director of government relations and corporate communications for Chugach Electric, told Petroleum News in a July 16 email that flexibility in the new contract could open up future opportunities for other gas suppliers.

In its tariff advice Chugach Electric says that it prefers not to be dependent on a single gas supplier but that at present there are no additional independent gas sellers capable of meeting the utility's gas volume and deliverability requirements.

Drop in gas usage

Chugach Electric's ability to fill its gas supply needs through to 2018 stems in part from a predicted substantial drop in the utility's gas usage between 2013 and 2015. That drop in usage will result from Homer Electric Association and Matanuska Electric Association bringing their own power generation facilities on line rather than buying Chugach Electric's power, and from Chugach Electric's use of a new, modern combine-cycle power station in Anchorage, a power plant that is much more efficient than the utility's old power station on the west side of Cook Inlet.

According to Chugach Electric's tariff advice, the utility's annual gas demand will drop from more than 20 billion cubic feet in 2013 to around 8.5 billion cubic feet in 2015 and thereafter.

However, Homer Electric and Matanuska Electric will need to purchase gas to fuel their new power generation plants. Homer Electric has said that it has secured adequate gas supplies for its new facilities through to March 2016 and is optimistic about meeting its needs through 2018. Matanuska Electric has been seeking gas supplies for a new power station it is constructing at Eklutna, north of Anchorage — that power station is slated to come on line in 2015.

Steyer said that the new contract with Hilcorp will help his utility but still leaves questions over the long-term gas supply situation from the Cook Inlet.

"While the contract with Hilcorp is positive news regarding Chugach's fuel supply in the near-term, we remain concerned about the long-term continued supply of gas for Southcentral Alaska," Steyer said. ●

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Enstar has new ConocoPhillips gas contract

Enstar Natural Gas Co., the main Southcentral Alaska gas utility, has a new gas purchase agreement with Cook Inlet gas producer ConocoPhillips. The new agreement, which covers the years 2016 and 2017, will enable Enstar to purchase a total of 4.75 billion cubic feet of gas. The gas will come from the ConocoPhillips-operated Beluga River and North Cook Inlet gas fields.

Enstar has filed a tariff advice with the Regulatory Commission of Alaska requesting commission approval of the purchase agreement. Gas prices under the agreement will be $7.27 per thousand cubic feet in 2016 and $7.57 in 2017. Those prices are a little less than price caps set for the sale of gas by Hilcorp Alaska, another Cook Inlet gas producer, under the terms of a consent decree agreed between Hilcorp and the State of Alaska following Hilcorp's purchase of Chevron's and Marathon Oil's Cook Inlet gas fields.

The purchase agreement with ConocoPhillips will provide for 1.8 billion cubic feet of gas in 2016 and 2.9 billion cubic feet in 2017, relatively modest volumes in comparison to Enstar's total predicted gas needs of 33.3 billion cubic feet and 34.9 billion cubic feet in those years. And, assuming that the Regulatory Commission of Alaska approves the new agreement, Enstar will still be left with 16.6 billion cubic feet of unmet needs in 2016 and 20.7 billion cubic feet of unmet needs in 2017. However, with Hilcorp having recently said that it anticipates being able to close the gap on Southcentral utility gas supplies through to 2018, there are presumably further new gas supply agreements in the offing.

—ALAN BAILEY

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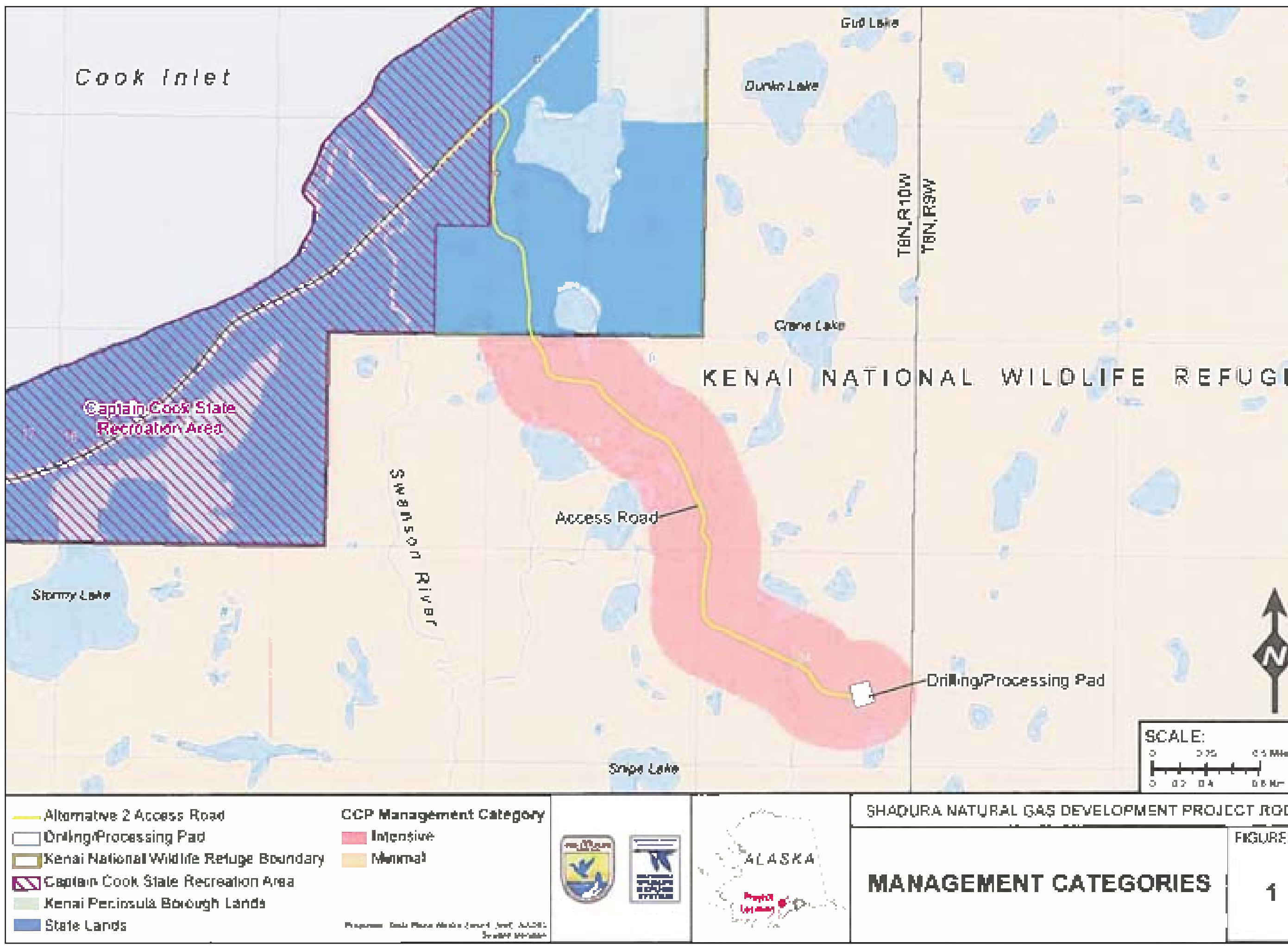
SHADURA GAS



What now?

NordAq is a small, Anchorage-based independent. It is among a number of companies looking to prove up new supplies of natural gas to replace declining reserves in the Cook Inlet region.

A company executive did not respond to requests for comment on the agency decision.

In early 2011, NordAq laid a temporary ice road to its Shadura prospect and drilled a wildcat exploratory well, the Shadura No. 1.

The company hasn't made clear the size of its apparent discovery. But the tentative development plans suggest a find worthy of some excitement.

The proposed Shadura development pad is more than a mile due east of the wildcat. For the EIS analysis, NordAq offered a two-stage development plan.

The first stage would include construction of a "minimal" drilling and processing pad. One gas well would be drilled and tested.

If the test results were unfavorable, all equipment and gravel would be removed and the affected areas would be restored to a preconstruction state, the EIS said.

If the testing results were favorable, a second stage would be built. This would involve expanding the pad and drilling five more gas wells, plus an industrial water well and a disposal well. Production facilities also would be installed on the pad.

The gas would tie into a ConocoPhillips Alaska natural gas pipeline to the northwest.

Overall, construction would take about 16 months, and the project would operate for 30 years, the EIS said.

Lease with CIRI

The Shadura project is in the northwestern section of the Kenai National Wildlife Refuge.

While the federal government owns the surface estate, Cook Inlet Region Inc. owns the subsurface estate of oil, gas and coal in the project area. NordAq has a lease with CIRI to develop the gas resource.

That NordAq would have access to the gas was never in question. Access to inholdings is provided for under ANILCA, the Alaska National Interest Lands Conservation Act.

The question was whether NordAq would get the kind of access it wanted.

At one point, the company told the Fish and Wildlife Service it would not move forward with the project if the access route had to come out of the Swanson River unit. Another company, Hilcorp, operates that unit, which has an existing road system.

In deciding to grant NordAq's wish (Alternative 2), Geoffrey L. Haskett, Alaska regional director for the Fish and Wildlife Service, wrote in the record of decision: "Alternative 2 reflects the Service's intent to manage Kenai Refuge to achieve the mission of the National Wildlife Refuge System, meet the purposes for which the Refuge was established, and meet our legal obligations." ●

Editor's note: A copyrighted oil and gas lease map from Mapmakers Alaska was a research tool used in preparing this story.

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NordAq seeks approval for Smith Bay work

NordAq Energy Inc. is planning a multiyear oil and gas exploration program in the Smith Bay area off the National Petroleum Reserve-Alaska and onshore in NPR-A.

The company holds a block of State of Alaska oil and gas leases in Smith Bay and a block of federal leases in the NPR-A northwest planning area. The NPR-A leases are inland to the southwest from Smith Bay.

NordAq, which has been exploring in the Cook Inlet area in recent years, applied to the Alaska Department of Environmental Conservation for an oil discharge prevention and contingency plan "on current and future lease holdings offshore at the southern extent of Smith Bay," DEC said in a notice published July 18. DEC said "drilling is proposed in shallow water and on shore in the Northwest National Petroleum Reserve-Alaska."

NordAq plans to drill as many as eight exploratory wells during the winter drilling seasons from 2013 to 2015, the agency said, with operations proposed "only during the frozen winter seasons" and a proposed drilling end date of April 21 each season to allow for demobilization and completion of any potential response activity prior to May 15, which is the average date of tundra travel closure, or loss of grounded sea ice in Smith Bay, which typically occurs in June or July.

DEC said access would vary depending on exploration location but would generally be via ice road, snow trail, Rolligon and/or airstrip.

—KRISTEN NELSON

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DECISION REVISITED

between oil and gas.

In its order the commission said: "It appears that all persons' correlative rights will be best protected by complete integration of interests in the Prudhoe Oil Pool," and scheduled a hearing for January 1996 to develop a plan for compulsory unitization of the Prudhoe Bay oil pool unless the commission determined that the unit owners were working "to integrate the separate and competing equities of the gas cap and oil rim within the Prudhoe Bay Unit."

Integration was finally accomplished in 2000 when Prudhoe Bay interests were aligned following BP's acquisition of ARCO and the acquisition of ARCO's Alaska interests by Phillips Petroleum Co.

In addition to ordering maximum production of NGLs through August 1996, the commission required submission of agreements that might affect the operation of the Prudhoe oil pool so it could "investigate whether the agreement contains anything that may impair correlative rights, reduce ultimate recovery or otherwise lead to waste," a provision which also expired at the end of August 1996.

—KRISTEN NELSON