Petroleum news

page 3 Giessel: resource issues will be oil tax focus for Senate committee

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Utilities take over new plant

CHUGACH ELECTRIC ASSOCIATION

The new Southcentral Power Project gas-fired power plant in Anchorage will substantially reduce the region's demand for natural gas for power generation. See story page 9.

Interior LNG requires private capital in addition to state funds

Although the Parnell Administration is asking lawmakers to approve a $325 million financial package this year to truck liquefied natural gas to the Interior, it is imagining a system costing as much as $1 billion, with the difference covered by the private sector.

"We're not just talking about building the plant. We're talking about providing a complete integrated system that creates the gas, trucks the gas and distributes the gas," Alaska Industrial Development and Export Authority Deputy Director for Infrastructure Mark Davis told the Senate Special Committee on In-State Energy at a Jan. 31 hearing.

Although one lawmaker called the $1 billion figure a "what if" number designed to estimate the cost of the project at its largest — including near-complete market saturation in the Interior with excess going to Southcentral — even the smallest version of the project would require at least $30 million of private money beyond the state package.

The Alaska Legislature is currently considering the package as Senate Bill 23 and House Bill 74, which both include

see **INTERIOR LNG** *page 20*

Senate tax discussions continue; PFC says state seen as tinkering

What factors have the most impact on Alaska's future oil and gas revenues?

Not the state's fiscal system, Janak Mayer told the Senate Special Committee on TAPS Throughput Jan. 31. The largest revenue impact is from something over which the state has no control, he said: oil prices, followed by production rate. The Senate committee was wrapping up its throughput-focused review of the governor's proposed tax changes as this issue of Petroleum News went to press, with the bill expected to move on to the Senate Resources Feb. 7 or Feb. 9.

The largest revenue impact is from something over which the state has no control, he said: oil prices, followed by production rate.

Mayer, a manager in PFC Energy's upstream practice and Tony Reinsch, senior director in the firm's upstream practice, presented an overview of how companies make investment decisions, where Alaska fits in the portfolios of the major North Slope producers and how competitive investment is in Alaska under the state's current production tax, Alaska's Clear and Equitable Share, or ACES, compared to competitiveness under the governor's tax change proposal, Senate Bill 21 (House Bill 72 is the companion bill).

see **TAX DISCUSSIONS** *page 17*

EXPLORATION & PRODUCTION

A holding pattern

Shell waiting on Kulluk investigations before deciding on next Alaska steps

By ALAN BAILEY
Petroleum News

On Feb. 1 while answering questions during a media webinar for Shell's announcement of its 2012 results, Shell CEO Peter Voser said that his company is waiting for the outcome of investigations following the grounding of the Kulluk, the company's floating drilling platform, before deciding on next steps in Alaska.

Work needs to be done on both of Shell's Arctic drilling rigs, to make the rigs ready for the 2013 drilling season, Voser said. The Noble Discoverer, the rig that Shell is using for Chukchi Sea drilling, requires "a series of upgrades," while the Kulluk

see **KULLUK PROBE** *page 19*

U.S. COAST GUARD

Shell wants to see the outcome of investigations of the grounding of its Kulluk floating drilling platform before deciding on its next steps in Alaska. The drilling platform will require repair before it can continue its Beaufort Sea drilling operations.

FACILITIES

Arctic port sites eyed

Army Corps, Alaska DOT select Nome and Port Clarence for feasibility analysis

By WESLEY LOY
For Petroleum News

A new report recommends development of a deep-draft seaport to support resource development, Coast Guard operations and other activity in the increasingly ice-free Arctic Ocean.

And the report picks two sites for port feasibility analysis: Nome and nearby Port Clarence. Both these locations are south of the Bering Strait, gateway to the polar ocean.

The draft report, titled "Alaska Deep-Draft Arctic Port System Study," is a product of the U.S. Army Corps of Engineers and the Alaska Department of Transportation and Public Facilities.

The study considered marine infrastructure needs over a vast area, from the Southwest Alaska village of Bethel west and north then east to the Canadian border.

It's part of efforts that began in 2008 to consider Alaska port needs, including along the remote Arctic Ocean coast.

As ice cover thins and recedes with climate change, and with Arctic shipping and offshore oil and gas exploration on the rise, many recognize the need for one or more northern ports capable of

see **PORT SITES** *page 18*

NATURAL GAS

Chevron sets LNG terms

Company's chairman says prices need to be 'close to oil parity' to support cost

By GARY PARK
For Petroleum News

Chevron has wasted no time sending a clear-cut message to potential Asian buyers of Canadian LNG: Unless sales are closely tied to, or on par with oil prices they can forget any contract deals.

Just over a month after striking a deal to become operator of Kitimat LNG, with Apache holding the remaining 50 percent, Chevron Chairman and Chief Executive Officer John Watson took a hard line, unwilling to continue the struggle Kitimat's former ownership group (Apache, Encana and EOG Resources) experienced in trying to arrange offtake orders.

"What we see is continuing growth in (LNG) demand. There's a lot of gas out there, but pulling these projects together and getting them online ... in time to meet that demand, is a different matter."
—Chevron Chairman and CEO John Watson

No sooner had Chevron moved into the venture that the "phone started ringing," he said. "We're a credible buyer in the marketplace and I think buyers throughout Asia, Japan and Korea are very interested in Chevron and interested in the project."

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Oil tax bill headed for Senate Resources

Committee Chair Cathy Giessel preparing by attending other hearings, a practice she began in the last session as a minority member

By STEVE QUINN
For Petroleum News

In sports terms, Sen. Cathy Giessel spent her first legislative term on the bench. But she took copious notes and now she's batting cleanup.

Giessel chairs Senate Resources and is about to have Senate Bill 21 land in her committee for review. It will be the second Senate committee to hear Gov. Sean Parnell's oil tax reform bill, following the Special Committee on TAPS Throughput.


SEN. CATHY GIESSEL

Getting to run the committee required paying special dues. Giessel spent two years in a minority caucus that did not receive many committee assignments.

That didn't stop the Anchorage Republican from attending nearly every committee hearing — House or Senate — that dealt with resource development issues.

She was as much a fixture as any committee member, but Giessel took a seat among the audience, armed with a note pad and a few pens, taking copious notes, ultimately preparing herself to handle some of the heavier hitting pieces of legislation almost immediately. Giessel sat down with Petroleum News and talked about what she learned and the resource development priorities she sees for the Legislature.

Petroleum News: You seem to have served a self-appointed apprenticeship for two years. You attended more hearings in some cases than committee members themselves. What drove you decision to do that?

Giessel: I feel it was my responsibility to be as educated as I could be. Whether I served on the committee or not, I wanted to be there hearing firsthand the discussion. So I felt it was my duty and still feel it is my duty, though my calendar is a bit more full these days, so I don't get to quite as many committees that I don't serve on. I have focused, however, on attending the two special committees: TAPS Throughput and In-State Energy. I'm not assigned to those committees but they are doing the preliminary work for subjects that will come to Resources. Again, I just want to be there and hear the discussion.

Petroleum News: So that style of commitment hasn't changed?

Giessel: No, it hasn't changed. I'm here to work. That's what my constituents elected me to do, to come and work for them.

Petroleum News: So with that style over those two years, what did you learn either about the job or about our state's resources?

Giessel: Wow, I learned a lot about our resources. As I look at (Legislature's consultant) PFC Energy presentations now — for example last week they were in the TAPS Throughput Committee — I look at the slides presented and compare to the information that PFC gave us last year and some of the metrics have moved a little as the world changes. Of course the petroleum industry is a worldwide market; it's dynamic, so some of the elements have changed in their presentation. I'm going to be asking them about that when they come before my committee. So it's been really good to have that background. Before I was elected I used to watch Gavel to Gavel pretty regularly, watching the (Senate) Finance Committee, and I particularly remember the in-depth discussions they had on decoupling and when (consultant) Pedro Van Meurs was before them, so it helps to have more of that historical background, I think.

Petroleum News: So knowing there was a change in that metric as you say, your investment into those two years seems to be paying off either with an appointment as a committee chair or an understanding of context.

Giessel: I think it's paid off significantly for me and in the information that I can share with my constituents based on those two years of sitting in committees and hearing all of the discussion. Of course, I couldn't participate in the committee itself, but certainly I could ask questions afterward of individuals and people testifying. But it gives me more information I could share with my constituents. Our founders believed strongly that our democracy would be held together by an informed citizenry. People are busy these days. They don't all watch Gavel to Gavel. So I feel it's my responsibility to learn as much as I can and share that information with them.

Petroleum News: Moving to this year, what would you say are your priorities this two-year session?

Giessel: No. 1 we've got to increase the amount of oil going through our pipeline, for a couple of reasons, the biggest one being that's our main source of revenue. The second one being that pipeline is being very stressed with the low throughput. It's becoming a real challenge to keep that equipment in tip-top shape. The best remediation is putting more oil through it.

The second one is energy. I live down in the Cook Inlet area. We are dependent on natural gas from Cook Inlet, but I'm a born-and-raised Fairbanks girl. My mother still lives in Fairbanks. She buys diesel to heat her home at a very high cost. My hometown is dying frankly. I'm very concerned we get natural gas from the North Slope down that central corridor of our state and branches out into rural areas as much as possible. There is of course other energy potential with the Watana Dam. I'm a very big supporter of hydroelectric: It's clean, dependable, durable and a great source of energy.

QA AND

The third one I don't have quite so much say in it, but we have to ramp back our spending to a more sustainable level. I'm a grandmother with three beautiful grandchildren and a fourth one on the way in about a month. I want those kids to be able to live here far into their lifetime. That means our budget has to be sustainable so we are not spending everything we earn today.

Petroleum News: You're going to get the oil tax bill very soon. How did having the bill spend time in the TAPS Throughput Committee help you?

Giessel: Having it in TAPS Throughput initially helped me in that I've heard the presentations already; I've already been thinking about what might be altered or not in the bill. I've seen some of the modeling already. So that's been helpful. Truly I haven't just been waiting for the bill to get to my committee. Our committee has been laying the groundwork. We've been looking at terms that are used in the oil fields. You know, what is a participating area; how are leases managed; how much resource is actually up there; what does the geology look like?

So laying that groundwork to prepare to manage that bill and altering our taxes to be more competitive and get more oil out of our fields. Our committee has not been just sitting there waiting.

Petroleum News: What are your thoughts on the bill?

Giessel: I think it's a pretty innovative bill. I like the elements in it. When I look at the governor's priorities, the features he wanted in it, they align with the things I'm interested in also: fairness to Alaskans. At this point we are giving out credits that never result in any production. That's not a fairness for Alaskans. It doesn't align our interests with the oil companies. We are paying for infrastructure, but does that result in more oil?

New production is a key piece. I was also very concerned about simplifying our tax. Again, listening to Pedro Van Meurs and PFC, a frequent message that

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● PIPELINES & DOWNSTREAM

Clearing way for Canol shale

Infrastructure, regulatory streamlining gain attention as activity picks up in Central Mackenzie; development could be 5 years away

By GARY PARK
For Petroleum News

Although commercial development of the Devonian Canol shale play in the Central Mackenzie Valley of the Northwest Territories is as far as five years down the road, the pressure is building to start planning for major oil and natural gas pipelines and to relieve a regulatory bottleneck in Canada's North, according to key players in the region.

John Hogg, vice president of exploration and development with MGM Energy, told a symposium in Calgary that if the Canol play takes off producers would need significantly more capacity than is currently available on Enbridge's existing Norman Wells oil pipeline to northern Alberta.

That system can carry up to 39,500 barrels per day, but is currently down to 13,000 bpd as the productive life of Imperial Oil's Norman Wells oil field continues to wind down after yielding about 300 million barrels.

However, Hogg said the Enbridge line is "nowhere near big enough", while the region does not have a gas line and "we're going to need one of those too."

He said the question that is looming is how fast Enbridge or TransCanada could build pipelines and what size would be needed.

"The next couple of drilling seasons will really tell us what the potential of this play is," Hogg said.

> *"Everything that is working in the Horn River you can now start to look for in the Canol and your opportunity for development starts to move forward."* **—Roy Benteau, petrophysical advisor for Vermilion**

Approval time a challenge

Adding to the challenges is the length of time it would take to gain approval to twin a line that already exists, he said, noting that it currently requires six to 15 months for MGM's regulatory group to obtain a permit for an exploration well, compared with six to eight weeks in Alberta.

Hogg said MGM is involved in only one or two wells a year, asking: "What happens if we go to development and we want to drill 20 or 30 wells a year?"

He said that if the Canol is deemed commercial, year-round drilling would dramatically reduce costs, assuming the Canadian government and industry build a road to Norman Wells, estimating that one-third of the drilling costs in the Central Mackenzie Valley are spent just getting to the site, including the use of a 240-mile ice road.

Hogg said the answer is to build all-weather roads as Husky Energy is doing this winter, overcoming the loss of ice roads in the spring melt and the constant maintenance to support heavy trucks.

Some help could be at hand if the Canadian government strikes a deal to transfer control over land, resources and water to the Northwest Territories government, ending years of inconclusive negotiations.

NWT officials in Ottawa

A large delegation from the NWT government, including Premier Bob McLeod, spent two days in Ottawa at the end of January meeting Prime Minister Stephen Harper and federal officials.

McLeod entered the meetings in an upbeat mood, suggesting the NWT is "on the verge of achieving devolution (of powers). We are advancing on many fronts. It seems like everything is coming together."

The prospect of a breakthrough is especially important for the mining industry, which the Conference Board of Canada predicted could see the value of output rise to C$1.3 billion in 2020 from C$732 million in 2011, with five new mines scheduled to open over the next four years.

A spokesman for Aboriginal and Northern Affairs Minister John Duncan said his government is determined to reach a deal "which will be an important and positive step in the evolution of Northern governance and will deliver economic benefits to the NWT."

The NWT government is confident that devolution will ease the regulatory burden that has been identified by Hogg and others as a barrier to development of the NWT's vast oil, natural gas and hydroelectric resources.

With four of seven aboriginal governments in the NWT having signed agreements-in-principle on devolution, McLeod believes there is sufficient backing from native communities to proceed if a pact is reached with the federal government.

MGM, Shell drilling

In the meantime, MGM, with Shell Canada as a partner, has spudded its first vertical exploration well in the Canol play, estimating it will take until about mid-February to drill, core and log.

Once drilling has reached target depth of about 6,700 feet, the well will be completed in the Canol and Bluefish zones and flow tested — operations that MGM hopes to complete by the second week of March.

Husky drilled two exploration wells last winter and plans to repeat the effort this winter.

MGM, Shell and Husky have joined ConocoPhillips and Imperial Oil in forming an explorers' group because, in Hogg's words, "we need to have synergies and share."

He said results from MGM and Husky drilling this winter should provide some clarity around oil and gas rates.

Although it will be difficult to achieve a stabilized flow over a short period of time "at least we'll get a sense of what the gas-oil ratio is. That's the critical element that we would all like to know."

Conoco spuds

In addition to the MGM and Husky drilling, the National Energy Board has reported that ConocoPhillips spudded an exploration well Jan. 26 and has approval for two more wells.

see **CANOL SHALE** *page 5*

ENVIRONMENT & SAFETY

Questions over Arctic dispersant use

Environmental consultant questions feasibility of using oil dispersant chemicals in responding to an Arctic offshore oil spill

By ALAN BAILEY
Petroleum News

Lauded by some as a major contributor to the cleanup of spilled oil following the 2010 Deepwater Horizon disaster in the Gulf of Mexico and slammed by others as environmentally dangerous, the use of chemicals to disperse oil slicks has become a controversial topic.

The concept behind dispersant use is simple. The dispersant chemicals, acting a bit like dishwashing liquid, break the oil into tiny particles, greatly increasing the surface area of oil exposed to water and hence greatly accelerating the rate at which oil-consuming microbes devour the oil, causing the oil to disappear.

But do dispersants, demonstrated in laboratory conditions, work in the hurly-burly of a real spill response situation? And, more particularly, would dispersants work, were there to be an oil spill catastrophe in the Arctic offshore?

Skeptical

Jeffrey Short, an environmental consultant working for Oceana, a marine conservation organization, is very skeptical about the potential effectiveness of dispersants in the Arctic. Short, who worked as a research chemist for the National Oceanic and Atmospheric Administration for 31 years and has published more than 60 scientific papers on Arctic pollution, spoke at the Alaska Forum on the Environment on Feb. 4, giving his views regarding the problems associated with dispersant use in the Arctic.

Short, who said he had been involved in the Deepwater Horizon response, working for private entities, said that claims about the effectiveness of dispersants during that response had been overstated, and that there was a lack of evidence for dispersant chemicals having had any impact in boosting the natural biodegradation of oil that had spewed from the out-of-control, seafloor well. For example, no one observed the milky appearance of dispersed oil in the water, he said.

And, although the government-published oil budget calculator for the Deepwater Horizon response indicated that dispersants had been somewhat effective, the technical underpinnings of that conclusion, as expressed in the budget calculator report, appear far short of convincing, he said.

A joint industry program, known as SINTEF and based in Norway, conducted a series of large-scale field experiments in the mid-2000s, testing the use of various response techniques, including dispersants, using oil deliberately spilled in the sea under carefully controlled conditions at an Arctic location.

Goldilocks circumstances

The effective use of dispersants requires a "Goldilocks" set of circumstances, in which the wind is strong enough to cause the necessary wave action for mixing oil with dispersant chemicals, but not so strong as to blow away the fine spray of dispersant, normally applied from an aircraft, Short said. And seas that are too rough can cause dispersants to escape into underlying water, rather than mix with an oil slick on the surface, he said.

Also, there is typically a relatively short time window following an oil spill, during which dispersants can be used, as evaporation and emulsification of the oil eventually renders the oil unresponsive to dispersant chemicals.

Given seasonal ice, the frequency of strong winds and the prevalence of sea fog in the Arctic Ocean, the appropriate conditions for the application of dispersants in Arctic seas may only occur for 10 percent of the time, Short said.

Lab tests

Short said that 10 years ago he had conducted some laboratory tests for the Prince William Sound Regional Citizens' Advisory Council, testing the effect of a commonly used oil dispersant on Alaska North Slope crude oil in sub-Arctic conditions. Those tests demonstrated that the dispersant did not work well in cold water, with dispersant effectiveness dropping with reduced water temperatures and with low water salinity, Short said. These results do not bode well for dispersant effectiveness in the Arctic — in addition to the effect of low water temperatures on dispersant action, melting ice in the Arctic seas tends to create a layer of low salinity water near the sea surface, he said.

Compounding the technical issues relating to the potential effectiveness of dispersants in the Arctic is the sparse transportation architecture for the resupply of dispersant chemicals to field responders, Short said.

Asked about the possibility that low water temperatures would slow oil degradation, thus extending the time window within which dispersants would be effective, Short responded that the weathering of oil is less sensitive to temperature than to wind, of which there is plenty in the Arctic. The rate of incorporation of water into the oil, a phenomenon that takes place quite quickly, depends on the composition of the oil, he said.

Continuing debate

Short's comments come amid a continuing debate over the realistic feasibility of conducting an offshore oil spill response in the Arctic. And a report, issued in November by the U.S. Arctic Research Commission and the U.S. Army Corps of Engineers, after overviewing the considerable body of research already done into oil spill response in the Arctic offshore made a number of recommendations for further research, including a recommendation that people evaluate the effectiveness of dispersants in Arctic conditions.

A joint industry program, known as SINTEF and based in Norway, conducted a series of large-scale field experiments in the mid-2000s, testing the use of various response techniques, including dispersants, using oil deliberately spilled in the sea under carefully controlled conditions at an Arctic location. SINTEF reported that it had found rates of oil weathering in broken ice conditions to be considerably lower than rates observed for the same oil in open water. The final report for the program also said that researchers had experienced success in dispersing oil in water around ice floes, by applying the dispersants from spray arms deployed from vessels and using the prop wash or jet motors of response boats to mix the dispersant with the oil.

Oil budget

A read of the technical documentation for the Deepwater Horizon oil budget calculator makes it clear that there was a wide range of expert opinion and no general agreement on the effectiveness of dispersants in the response to that disaster. A December 2012 paper in the Proceedings of the National Academy of Science presents an overview of the scientific findings from Deepwater Horizon. Written by senior officials from several federal agencies, including the U.S. Geological Survey and the National Oceanic and Atmospheric Administration, the paper says that monitoring of oil in the water through a variety of techniques had provided oil particle size data consistent with expectations from chemical oil dispersion. The oil budget calculator subsequently concluded that chemical dispersion accounted for about 16 percent of the oil that had escaped from the well, the paper says. ●

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CANOL SHALE

The conference, sponsored by CI Energy Group, also heard Colleen Sherry, senior tight oil regional geologist for Vermilion Energy, draw similarities between the Horn River Basin of northeastern British Columbia and the Central Mackenzie Valley shales.

She and Roy Benteau, petrophysical advisor for Vermilion, had identified the Canol play when looking to replicate the Horn River in the oil window, but their company opted not to post the land, leaving MGM to snap up a large portion of the rights.

"Everything that is working in the Horn River you can now start to look for in the Canol and your opportunity for development starts to move forward," Benteau said, describing the larger pores in the Canol as similar to what might be seen in the Eagle Ford in Texas. ●

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● LAND & LEASING

State sets May 8 date for spring sales

Augustine geothermal competitive sale added to schedule; Cook Inlet, Alaska Peninsula areawide oil and gas sales offered annually

By KRISTEN NELSON
Petroleum News

Bids will be opened beginning at 9 a.m. May 8 for three state competitive lease sales — two oil and gas and the third geothermal.

The Alaska Department of Natural Resources, Division of Oil and Gas, said in Feb. 1 notices of sale that the Alaska Peninsula areawide 2013 and Cook Inlet areawide 2013 oil and gas lease sales, and the Augustine Island geothermal competitive bid sale will take place at the Dena'ina Civic and Convention Center in Anchorage.

Cook Inlet lease rental rates are $10 an acre for the first through the seventh years of the lease and $250 an acre for the eighth through the 10th years of the lease.

Detailed sale information is available on the division's website at http://dog.dnr.alaska.gov. The division said a tract maps for the three sales will be released after March 18.

Fourth geothermal sale

In a Feb. 4 press release on the upcoming sales the division said the Augustine Island sale is the fourth geothermal lease sale the state has held. The most recent sale was in 2008 for acreage on Mount Spurr on the west side of Cook Inlet.

The Augustine geothermal sale, the first geothermal sale in the Augustine area of Cook Inlet, has a minimum bid of $1 per acre; the primary term of leases will be 10 years, renewable for an additional five years; the annual rent will be $3 an acre; and the royalty rate will be 1.75 percent of gross revenues from production, sale or use of geothermal resources during the first 10 years the resource generates gross income and 3.5 percent of gross revenues after that first 10-year period. Rent and royalties will be renegotiated 20 years after initiation of commercial production.

The 65,992-acre area is divided into 26 tracts from 2,489 to 2,560 acres covering the entire Augustine Island including some tidelands and adjacent waters.

(There is a story on the Augustine leasing proposal in Jan. 27 issue of Petroleum News.)

Alaska Peninsula sale

For the Alaska Peninsula areawide 2013 oil and gas lease sale the minimum bid is $5 per acre with a fixed royalty rate of 12.5 percent and a 10-year term for all tracts.

There are 1,047 tracts in the Alaska Peninsula sale, ranging in size from 1,280 to 5,760 acres of state-owned uplands and tide and submerged lands on the north side of the Alaska Peninsula from the Nushagak Peninsula to just north of Cold Bay.

The 2005 Alaska Peninsula areawide sale drew $1.15 million in high bids from Shell Offshore Inc. and Hewitt Mineral Corp. on 37 tracts, some 190,494 acres. Hewitt picked up an additional tract in the 2007 sale; sales held annually in 2008 through 2012 drew no bidders and there are no remaining active leases in the area.

Cook Inlet sale

The division noted that "the Cook Inlet hydrocarbon basin has seen a resurgence in investment by small, medium-sized and large energy companies" in the past two years.

"Cook Inlet still holds significant resources and we are hoping for a continued trend of successful lease sales and increased drilling activity," division Director Bill Barron said Feb. 4.

There are 815 tracts ranging from 1,280 to 5,760 acres in the Cook Inlet sale with a minimum bonus bid of $25 an acre for all tracts, a fixed royalty of 12.5 percent and a lease term of 10 years.

Cook Inlet lease rental rates are $10 an acre for the first through the seventh years of the lease and $250 an acre for the eighth through the 10th years of the lease. Annual rentals may revert to $10 an acre after sustained production or "at the state's discretion after the lessee meets certain conditions."

The division said that after sustained production has begun "or the state otherwise determines in its sole discretion, upon request, that the lessee has exercised reasonable diligence in exploring and developing this lease" the annual rental may be set at $10 per acre or fraction of acre.

In its Cook Inlet sale announcement the division said: "In evaluating a request to decrease rental based on the exercise of reasonable diligence, the state will consider the funds expended by the lessee to explore and develop this lease and the types of work completed by or on behalf of the lessee on this lease."

The state first set these variable-rent lease terms in its fall 2011 lease sales, and Barron said at that time that the state's goal was to "encourage people to prudently and responsibly explore and delineate their acreage within the primary lease term." ●

Contact Kristen Nelson at knelson@petroleumnews.com

GOVERNMENT

BSEE, NEB partner on Arctic safety

The U.S. Bureau of Safety and Environmental Enforcement and the Canadian National Energy Board are partnering to promote Arctic offshore safety.

The agencies said Feb. 5 that a memorandum of understanding was signed by BSEE Director Jim Watson and NEB Chair and CEO Gaetan Caron in Washington, D.C., Feb. 4. The MOU encourages information sharing and cooperation between the regulators on government energy policy, regulatory development, specific energy projects and best practices.

"BSEE and NEB both have a shared commitment to reduce the risks associated with offshore drilling in the Arctic," Watson said in a statement. He said the MOU "establishes a means for our two agencies to share data and experiences as expeditiously as possible so that we can identify and react effectively to industry-wide risks."

Gaetan said the agreement "lays the groundwork for cooperation on matters of mutual interest between our two agencies, and it's an important step in sharing best practices and supporting effective regulatory outcomes."

The MOU is effective for five years and renewable every five years; it may be modified jointly or discontinued at any time by either participant.

—PETROLEUM NEWS

ENVIRONMENT & SAFETY

Finding ways of seeing oil under ice

OSRI tests the use of surveillance balloons and underwater vehicles for detecting oil caught below ice following an oil spill

By ALAN BAILEY
Petroleum News

If the unthinkable happens and oil is spilled in sea ice conditions in the Arctic, spill responders will be faced with the challenge of locating oil trapped under ice floes. Oil, being lighter than water, would float towards the sea surface but would likely become caught in hollows in the underside of the floating ice cover.

The Oil Spill Recovery Institute, or OSRI, an organization based in Cordova, Alaska, that supports oil spill research, has recently been conducting a couple of projects, aimed at finding new ways of detecting oil trapped in this sub-ice situation, Scott Pegau, OSRI research program manager, told the Alaska Forum on the Environment on Feb. 4.

One project, involving the use of tethered surveillance balloons, is aimed at determining whether the warmth of the oil can be detected from above the ice using infrared cameras. The other project has entailed researching the possibility of detecting oil from under the ice using remotely operated or autonomous underwater vehicles.

Cheap and portable

A particular appeal of the tethered surveillance balloon concept is the low cost and easy portability of the technology, coupled with the ease of permitting of its use, Pegau explained. The use of drones, an alternative means of achieving aerial surveillance, is very difficult to permit he said.

With limitations on how much flying may be practical along the Alaska coastline, the OSRI researchers sought some type of technology that could be deployed from a boat in a wide variety of different weather conditions, Pegau said. And modern kite-style balloons can be operated in wind strengths up to 80 knots, he said.

An infrared camera mounted on a balloon, which is tethered to a boat, can use wireless transmission to send video images to a receiver operated by responders on the boat. Thus, the responders can obtain an immediate, elevated view of sea ice in their vicinity.

A test using a balloon tethered to a truck on the North Slope demonstrated that the infrared camera could detect warm water that the researchers had allowed to seep under the snow.

"They're moving their eyes from 30 feet off the water to 500 feet off the water," Pegau said.

A test using a balloon tethered to a truck on the North Slope demonstrated that the infrared camera could detect warm water that the researchers had allowed to seep under the snow. Another test, using an Alaska Clean Seas vessel in Harrison Bay, to the west of Prudhoe Bay, enabled people on the boat to obtain a birds-eye view of an adjacent ice sheet, with the infrared image showing that the ice was sufficiently weak to allow passage of the boat, an observation that could not be made from the level of the boat's deck.

Underwater observations

The underwater vehicle concept involves both the visual detection of dark oil against a reflective ice surface and the detection of oil using a sonar system, rather like a depth sounder as used by fishing vessels. The visual detection system would entail shining a beam of light upwards at the underside of the ice and then using a camera system to detect light reflected back downwards.

Tests using oil injected under half-meter-thick saltwater ice in the Cold Regions Research and Engineering Lab's test tank in New Hampshire proved promising. A camera system mounted on an underwater cart could easily detect dark material juxtaposed against the ice, Pegau said. And the acoustic system, also mounted on the cart, provided information about the depth of the oil and the extent to which the oil had been disturbed, he said.

Future tests of the underwater systems would evaluate how far it might be possible to see into the ice, and the extent to which it would be possible to detect oil encapsulated in the ice, Pegau said. And OSRI sees its system as complementary to ground penetrating radar, a technology that is used above an ice sheet to seek trapped oil, he said. ●

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GOVERNMENT

Canada to raise offshore liability cap

Canada's offshore players — explorers, producers, pipelines and marine shippers — have been told by Environment Minister Peter Kent they can expect a new regime that will include "significant" changes to liabilities for polluters.

He said legislation will shortly be introduced in response to the pressure to diversify Canada's oil and natural gas markets, offshore drilling and greater pipeline shipments.

Government sources have indicated the liability cap could be raised to "billions of dollars" from the current C$40 million in the Beaufort Sea and C$30 million off the East Coast, which have been described since BP's Macondo well blowout, as de facto subsidies for offshore operators.

The sources suggest that the industry will have to either buy insurance or "self-insure" to cover the financial risks from a blowout or spill.

Natural Resources Minister Joe Oliver said the liability system is being reviewed "to make certain that Canada's polluter-pay system remains among the strongest in the world" at the same time the government is strengthening maritime protection by requiring double-hulled vessels, enhanced navigational aids and increasing inspections of federally regulated pipelines by 50 percent.

Pressures intensifying

Those pressures have been intensifying as the petroleum industry has advanced plans to export oil sands bitumen and LNG from the British Columbia coast and companies move forward with plans to explore the Beaufort and the Atlantic offshore regions.

Travis Davies, a spokesman for the Canadian Association of Petroleum Producers, said the organization is working with its member companies in Atlantic Canada to develop an industry position on changes to the existing regime in hopes of being consulted on what changes the government is contemplating.

"Once we have a position, we'll be constructive participants in the government process, submitting input which will be public," he said.

Will Amos, director of the Ecojustice environmental law clinic at the University of Ottawa, said companies "should face unlimited absolute liability for spills, in accordance with the polluter-pays principle," arguing that an "offshore spill lingers forever."

Scott Vaughan, Canada's commissioner of the Environment and Sustainable Development, is scheduled to release a report in February that examines what systems are in place to protect taxpayers against the cost of accidents in the mining, nuclear, offshore oil and gas and marine transportation sectors.

—GARY PARK

● EXPLORATION & PRODUCTION

AOGCC halts new Meltwater drilling

AOGCC wants more information about why MI is migrating into shallower formations before ConocoPhillips can continue drilling

By ERIC LIDJI
For Petroleum News

The Alaska Oil and Gas Conservation Commission is telling ConocoPhillips Alaska Inc. to hold off on drilling at a Kuparuk River unit satellite until the company and regulators can better understand why injected fluids have been migrating into shallower formations.

Starting in April 2002, ConocoPhillips noticed elevated pressures in the outer annulus — the area between the outer walls of a well at the surrounding geologic formation — of development wells in the Meltwater Oil Pool. Gas samples suggested that the miscible injectant used to enhance oil recovery in the field was migrating into the outer annulus.

For years, ConocoPhillips provided "periodic updates of monitoring and diagnostic efforts to the AOGCC" while it continued to make injections, but last year the company said a recent 4-D seismic evaluation determined that MI fluids were, in fact, migrating to shallower strata in the area. After ConocoPhillips made some adjustments to its reservoir management practices at Meltwater, the AOGCC in October 2012 allowed the company to continue MI injections under certain reporting requirements and pressure restrictions.

Because there are no potential underground sources of drinking water in Meltwater, the migration should not contaminate drinking water, but does violate AOGCC regulations.

Subsequently, ConocoPhillips asked the AOGCC to make six changes to the Area Injection Order for enhanced oil recovery at Meltwater, first among them being to expand the definition of the reservoir to include the shallower strata where the MI is migrating.

Currently, the reservoir only includes the Bermuda interval of the Meltwater sands, defined as extending from 6,785 feet to 6,974 feet in the Meltwater North No. 2A well.

ConocoPhillips wanted to move the top of the zone to 2,503 feet. The change would have included the Cairn — an interval extending from 6,411 feet to the top of the Bermuda.

When Phillips Alaska Inc. initially applied for Meltwater pool rules in 2001, it asked the AOGCC to include the Cairn in the reservoir, but the AOGCC decided "insufficient information is available to include the Cairn interval in the (Meltwater pool) at this time."

Following a November 2012 hearing — where ConocoPhillips presented some testimony confidentially — the AOGCC denied the request, saying it would have violated existing state regulations. The AOGCC also denied a request from ConocoPhillips to allow it to skip weekly well monitoring during extreme weather and other emergencies. The AOGCC did, however, grant ConocoPhillips' request to add several rules to the Area Injection Order covering well integrity, confinement of fluids, and injection pressures.

Now, the AOGCC is telling ConocoPhillips not to drill any new wells, or to convert any existing productions wells to injection wells, at Meltwater until the issue is resolved.

While noting that ConocoPhillips' reservoir management adjustments at the pool appeared to be "allowing migration pathways to close," the AOGCC said "more data are needed to assess the effectiveness of these migrating practices." Starting in November, ConocoPhillips launched an 18-to-24-month study of the overburden in the area that the AOGCC called "critical" for understanding the characteristics of the Meltwater Oil Pool.

The AOGCC also determined that the reasons ConocoPhillips gave during the hearing for keeping certain material confidential did not meet state standards, but decided not to add those materials to the public record until after the end of the appeal period for the case.

Phillips Alaska Inc. discovered the Meltwater satellite in May 2000 and brought the satellite — the fourth at the Kuparuk River unit — into production in November 2001.

The company began its MI program at Meltwater in January 2002. ●

Contact Eric Lidji at ericlidji@mac.com

CHUGACH ELECTRIC ASSOCIATION

The new Southcentral Power Project gas-fired power plant in Anchorage will substantially reduce the region's demand for natural gas for power generation.

● UTILITIES

Utilities take over new power plant

Combined cycle power generation replacing old plant will significantly reduce gas consumption by Southcentral power utilities

By ALAN BAILEY
Petroleum News

On Jan. 31 Chugach Electric Association took over the operatorship of the new Southcentral Power Project electricity generation facility that Chugach Electric and Municipal Light & Power have constructed in Anchorage. The new power station had been delivering power to the Railbelt electrical grid for several months as part of the testing and commissioning of the facility but the handover from SNC-Lavalin Constructors, the contractor that built the facility, represented the facility's formal completion.

The transfer of the $369 million project to Chugach Electric took place well ahead of its originally planned June date, the power utility said in a Feb. 4 press release. Chugach Electric is operating the plant on behalf of itself and Municipal Light & Power, the joint owner.

Natural gas savings

"I'm very proud of the work by Chugach staff and managers to bring this project to fruition on behalf of the two utilities and the thousands of consumers they serve," said Janet Reiser, chair of the Chugach Electric Board of Directors.

And, with modern, combined-cycle power generation equipment, the 183-megawatt gas-fired power plant will consume about 25 percent less gas per kilowatt-hour than the decades-old and inefficient Southcentral power generation capacity that the plant is displacing. The consequence will be a reduced demand for natural gas from the declining gas fields of the Cook Inlet basin and a reduced cost of power generation for Southcentral electricity consumers.

Chugach alone estimates that the new plant will cut its annual natural gas consumption by 3 billion cubic feet a year, an annual savings of more than $15 million for its customers, the utility said.

However, consumers can expect an initial rise in electricity rates by 4 to 6 percent, to enable the utilities to recover the cost of building the new facility, Chugach Electric said. ●

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EXPLORATION & PRODUCTION

Repsol and Linc get AOGCC permits

The Alaska Oil and Gas Conservation Commission issued two drilling permits at the end of January for Repsol E&P USA Inc. to explore its Qugruk prospect on the North Slope.

On Jan. 25, the AOGCC issued a permit for Repsol to drill the Qugruk No. 6 well on ADL 391394. The coastal well would be mostly vertical but move slightly to the north. On Jan. 31, the AOGCC issued a permit for Repsol to drill the Qugruk No. 3 well on ADL 391445. The onshore well is also mostly vertical, but moves slightly to the south.

Repsol is planning a three-well program this winter across the Qugruk prospect. The prospect is in a narrow fairway between the Oooguruk and Colville River units.

The AOGCC also issued a permit Jan. 25 for Linc Energy Operations Inc. to drill Umiat DSP No. 1, a Class II disposal well at the oil field in the Brooks Range foothills.

The company received a corresponding drilling permit Jan. 18 from the U.S. Bureau of Land Management, the agency that oversees drilling on federal lands.

The well would be on federal lease AA081726. The well is the first in a four-to-six well program Linc is planning at Umiat this winter.

In January, Linc also applied for BLM permits to drill the Umiat No. 16 and Umiat No. 18 wells. Umiat No. 16 would be vertical well on federal lease AA084141 to test an oil-bearing interval in the Lower Grandstand formation. Linc previously described the Umiat No. 18 well as an alternate location it planned to drill this winter if time permitted.

—ERIC LIDJI

• NATURAL GAS

NA LNG looks to exporting to survive

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

By BILL WHITE

Researcher/writer for the Office of the Federal Coordinator

Japanese, Korean and Taiwanese officials told foreign LNG makers in September 2012 that their prices are out of whack given what's going on in North America. Japan is enduring its first trade deficit since the early 1980s in part due to paying high LNG prices.

Some think today's price gap could narrow quickly.

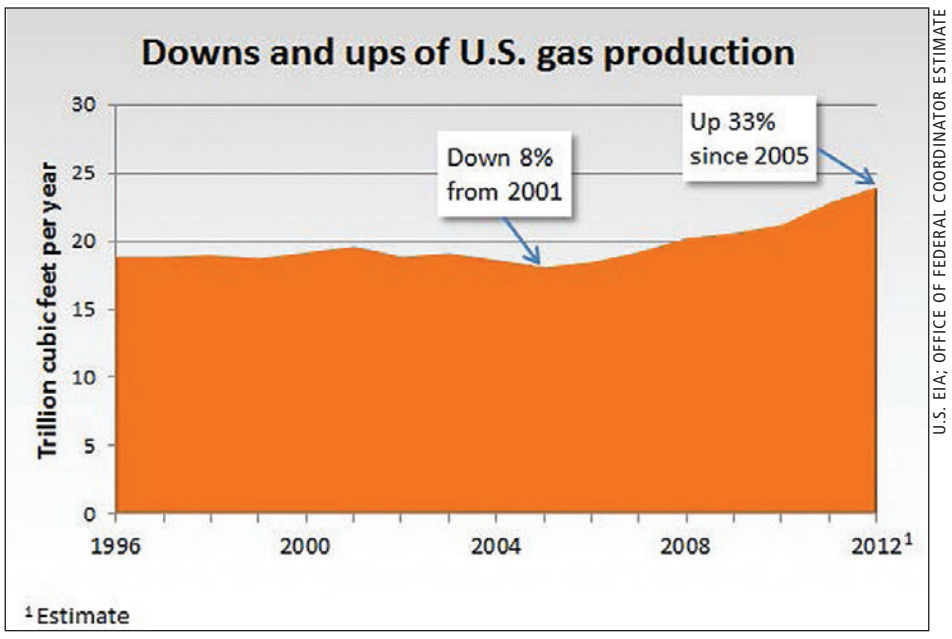
BILL WHITE

As one former Energy Department official told The New York Times recently, "I know the pitch about our price differentials will justify the high costs of LNG. We will see. Gas by pipeline is a good deal. LNG? Not so clear."

Medlock, the Rice University energy economist, published a paper in 2012 predicting North American LNG exports will lose money.

Today's extremely low North America prices are an aberration due to the newfound glut of shale gas, Medlock argued. Producers and markets will adjust, prompting the price to rise.

Today's extremely high prices elsewhere, especially in Japan, the world's top LNG buyer, also are an aberration due LNG prices linked to soaring oil prices, exacerbated by a demand spike after Japan's Fukushima nuclear power plant disaster in 2011, Medlock said.



U.S. EIA; OFFICE OF FEDERAL COORDINATOR ESTIMATE

Today's extremes cannot last. Other countries will start producing shale gas. More pipelines will get built to supply China, freeing more LNG for Japan and South Korea. New liquefaction projects could sprout in Russia, East Africa and elsewhere besides North America.

When prices migrate to more reasonable and sustainable levels, the arbitrage opportunity will vanish, he said.

The global gas price differences will not be "sufficient to support long-term baseload LNG exports from the U.S. Gulf Coast to these regions (Asia and Europe)," he said.

North American export sites could be profitable as seasonal suppliers or as providers of storage capacity for European and Asian markets. "In fact, it would not be surprising to see Asian utilities taking storage positions in the U.S. to hedge seasonal price fluctuations. ... This is a distinctly different type of arrangement from a baseload LNG supply deal," Medlock said.

Cheniere Energy, the first mover to add liquefaction to its Louisiana import terminal, has found buyers for all of its 2-bcf-a-day output. British trader BG Group, Spain's Gas Natural Fenosa, Korea Gas Corp. and GAIL (India) have signed 20-year contracts.

Cheniere's 2011 annual financial report says that collectively the four companies have committed to pay $2.3 billion annually for liquefaction services.

For Charif Souki, Cheniere CEO, to shift to liquefaction is an act of survival.

The company was near bankruptcy, he told a London gas conference in October 2012. He needed to find a way to salvage Cheniere's investment in storage tanks, tanker berths and the rest.

"For us it was a matter of life and death," Souki said.

Import mania

Ten years ago, the world looked very different to Souki and other industry executives.

They were joining the stampede to build or expand LNG import terminals.

"At one point in the early 2000s there were over 47 regasification (import) terminals with certification for construction, which was a clear signal regarding industrywide expectations for significant declines in future U.S. production," Medlock said.

1 2 SERIES

U.S. production did drop. From 2001 to 2005, production fell 8 percent, the equivalent of 4.3 bcf a day.

The pressure was on to bring more supply to U.S. consumers.

In late 2002, while considering an application for the Cameron LNG terminal eventually built in Hackberry, La., FERC made a significant decision: It would not take into consideration the financial viability of LNG projects brought to the commission. The project developer and its customers would bear the "economic risk." FERC would focus on environmental impacts, operational safety and other matters. The new policy lowered the hurdle a project needed to clear to get FERC's blessing.

Applications to build or expand LNG import terminals flooded in. Big names backed some of them: producer ExxonMobil; global gas trader BG Group; pipeline companies Veresen, Trunkline and El Paso; gas utility Sempra Energy.

In a 2004 letter to FERC's chairman, U.S. Sen. James Inhofe, R-Okla., chairman of the Committee on Environment and Public Works, urged quick action in the face of a looming "energy crisis" from falling gas production and rising demand. "The government can help the country meet its energy challenges by increasing access to new LNG sources and permitting new LNG receiving terminals in the communities that want them," he wrote.

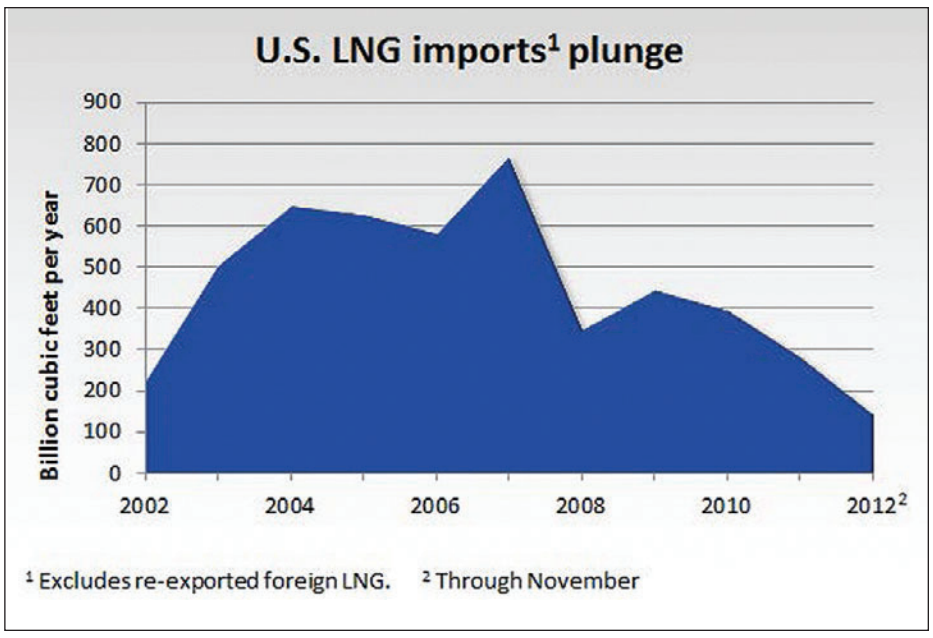
Federal Reserve Chairman Alan Greenspan said "our limited capacity to import LNG effectively restricts our access to the world's abundant supplies of natural gas," and that "we need to get in place, as soon as we can, the capability of fairly substantial imports that enable our manufacturers who use natural gas to compete internationally."

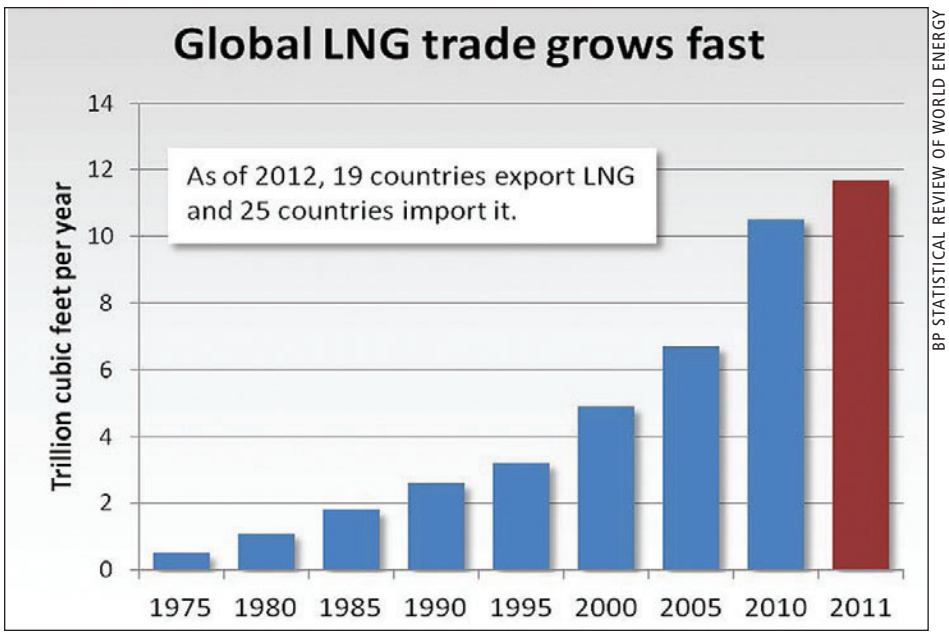
In 2006, a FERC official reported to the commission that the agency had approved 14 projects — 11 new terminals and three expansions — that could supply North American consumers with up to 25 bcf a day of imported LNG.

That wasn't all. FERC had pending applications for 10 more new terminals and two expansions, with nine other sites in preliminary planning for terminals. Another federal agency that oversees offshore LNG terminals was considering

see **LNG EXPORT** *page 11*

U.S. OFFICE OF FOSSIL ENERGY





BP STATISTICAL REVIEW OF WORLD ENERGY

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LNG EXPORT

eight proposals.

LNG started pouring into the United States. Imports more than tripled from 2002 to 2007, when they reached more than 2 bcf a day — averaging about a ship every other day.

Import terminal construction continued with a rose-tinted view of the future. It turned out the optimism was misguided. Unfortunately for investors, import terminals take years to build and the momentum was too strong for some projects to stop work even when it became clear the market was changing.

The last two terminals started up in 2011: The Qatar Petroleum/Exxon Golden Pass project at Sabine Pass, Texas, (practically next door to Cheniere's terminal) and the Kinder Morgan/GE Energy terminal at Pascagoula, Miss. Neither of those terminals received any LNG in 2012. Both have applied to add export capability.

Some projects, however, do have cash flow, despite little or no gas moving through the plant. Customers have reserved import capacity whether or not they use it. Those contracts allowed developers to obtain construction money.

For example, Chevron and Total each are obligated to pay Cheniere $125 million a year to 2029 for rights to its Louisiana plant, according to Cheniere's annual financial report.

But mostly Cheniere's and the other plants stand idle.

As it turned out, 2007 was the peak year for LNG imports — at roughly 4 percent of U.S. supply.

In 2012, net LNG imports averaged about 0.4 bcf a day, or less than 1 percent of supply. Half went to New England, where gas-pipeline constraints cause a bigger demand for LNG.

A future of exports?

As was said, Cheniere hopes its first LNG will depart its plant in 2015, with more production trains (or units) to come online in 2016 and 2017.

Soon thereafter, sponsors of other proposed Louisiana plants as well as some targeted for Texas, Maryland and Oregon hope to start up.

First they'll need regulatory approval.

The Department of Energy, which authorizes exports, expects to be busy this year processing applications now that its economic impact studies of exports are drafted. The reports concluded exports would cause U.S. consumers to pay somewhat more for natural gas but that virtually any amount of exports would boost the nation's economy more than they would hurt.

FERC authorizes LNG plant construction and operation. As of early January it had formal environmental reviews under way for three proposed projects and preliminary environmental work begun on a handful of others.

Authorizations take a project only so far, however. Projects need customers so they can convince the financial community to lend or invest the billions needed for construction.

Cheniere's Louisiana project is the sole terminal to have customers locked in.

Some proposals have struck tentative deals with possible buyers, for example a Freeport, Texas, project with two Japanese utilities, and a Hackberry, La., project with multinational Japanese and French trading companies.

Separately, Japanese, Korean, Chinese and Malaysian companies have talked of investing in West Coast Canada export proposals.

North American projects, including one under consideration in Alaska, aren't alone in believing there's money to be made supplying the world with LNG.

Projects proposed in East Africa, Israel and Russia are getting at least preliminary looks, adding to the seven export terminals under development in Australia.

As with the plethora of North American projects, handicappers don't believe all can proceed in the next decade.

Meanwhile, in the United States, a diverse set of groups oppose LNG exports.

Environmental groups say exports will encourage more shale-gas drilling, leading to the potential for greater air and water pollution. They oppose individual projects on specific grounds. For example, before FERC authorized Cheniere's construction, two groups attacked from 360 degrees: They said tanker ballast water will harm aquatic life, construction will throw dust into the air, wastewater will impair drinking-water quality, air emissions will worsen atmospheric ozone formation, hurricane storm surges will flood the site, and LNG-tanker traffic will tax Coast Guard resources.

Terminal neighbors worry about industrial activity worsening their quality of life.

Gas utilities warn that exporting domestic gas will raise U.S. prices and burden consumers.

The chemical industry cautions that higher prices for its gas feedstock could dampen their desire to expand U.S. operations.

For the Cheniere project, FERC considered all of the concerns before approving the project. The commission generally held that the environmentalist concerns were ill-founded or speculative. The commission did acknowledge that if a cluster of neighboring LNG projects all apply, they could have a collective environmental impact that FERC needs to consider.

At least four other proposed export projects lie in the same "air quality control region" as Cheniere's plant, the commission said. But none had applied to FERC for a construction certificate when the commission sanctioned the terminal.

"The project sponsors have not yet filed an application or started the pre-filing process at the commission, and construction timelines and in-service dates are unknown," FERC said in its Cheniere order. "It is speculative to assume construction emissions would overlap. In addition, each facility can vary by size and proposed power source for the liquefaction equipment, which can greatly vary the resulting operating emissions of criteria and greenhouse gas pollutants.

"Thus, without additional information regarding equipment sizes and fuel sources, we are unable to identify these other facilities' operating impact on air quality or climate change."

For LNG export entrepreneurs, the stakes of their new direction are big — multibillion-dollar big.

A decade ago they looked out over the horizon and saw a fantastic future of inbound LNG tankers queued up to deliver liquid methane to needy North American consumers. The fleet never set sail, and nothing but blue breakers came to shore.

The vision was a chimera, but it left room for a new vision, one of outbound tankers, laden with North American LNG, steaming to distant ports to help feed the world's growing appetite for natural gas. ●

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

Note: Part 1 of this story appeared in the Feb. 3 issue of Petroleum News.

EXPLORATION & PRODUCTION

January ANS production down almost 1%

Alaska North Slope crude oil production averaged 576,959 barrels per day in January, down 0.9 percent from a December average of 582,149 bpd.

Cook Inlet, with its much smaller volumes, saw a 7.4 percent increase in December over November, averaging 12,072 bpd compared to 11,243 bpd in November.

Except where noted, North Slope volumes are from the Alaska Department of Revenue's Tax Division, which reports oil production consolidated by major production centers and provides daily production and monthly averages for the most recent month.

Cook Inlet volumes, and those for individual North Slope fields, are from the Alaska Oil and Gas Conservation Commission, which reports production by pool and field on a month-delay basis.

Cook Inlet

The 7.4 percent December-over-November production increase from Cook Inlet was driven by Hilcorp Alaska's Swanson River field, which averaged 2,028 bpd in December, up 158 percent from a November average of 786 bpd.

John Barnes, Hilcorp Alaska senior vice president, said in a December talk at Commonwealth North that there were a lot of wells that needed to be fixed at Swanson River when Hilcorp took it over (in January 2012). He said Hilcorp has been operating a drilling rig and using a pulling unit for well remediation at the field, as well as bringing in a workover rig (see story in Dec. 16 issue of Petroleum News.) Barnes said Swanson River was producing 300 bpd when Hilcorp took it over, but Dec. 7, the day of his talk, the field was producing 2,200 bpd, with one recently completed well producing at more than 1,000 bpd.

With the increase at Swanson River, there are now four Cook Inlet fields producing more than a thousand barrels a day: the Hilcorp-operated Granite Point field, which averaged 2,130 bpd in December, down 0.5 percent from November; the Hilcorp-operated McArthur River field, which averaged 3,947 bpd in December, down 8.9 percent from November; and Middle Ground Shoal, operated by

see **ANS PRODUCTION** *page 14*

● GOVERNMENT

Sen. Murkowski rolls out energy 'vision'

Describes her wide-ranging report as a conversation starter, calls for opening ANWR and improving NPR-A access

By WESLEY LOY
For Petroleum News

Energy is good. So begins a new report from U.S. Sen. Lisa Murkowski titled "Energy 20/20: A Vision for America's Energy Future."

Murkowski, an Alaska Republican, released the 123-page report on Feb. 4 in Washington.


SHANE LASLEY
SEN. LISA MURKOWSKI

She said the document is not the makings of a comprehensive energy bill. Rather, it is "meant to begin a conversation" for the new 113th Congress.

Murkowski is the top-ranking Republican on the Democrat-controlled Senate Committee on Energy and Natural Resources. The chairman is Sen. Ron Wyden, D-Ore.

Murkowski's "Energy 20/20" is a sweeping and largely familiar wish list of projects and policies for Alaska and the nation. The document includes sections on conservation, clean energy technology, environmental responsibility and "effective government."

During a press conference on the report, the senator said developing new technologies is key for reducing harmful greenhouse gases. But she said policies that inflate energy costs won't fly at home, where rural Alaskans already face crushing prices for fuel.

The first and largest section of the report is called "Producing More," and covers oil and gas, coal, unconventional fossil fuels such as shale oil and methane hydrates, renewables such as hydro and solar, and nuclear power.

"The United States should establish a national goal to produce enough additional oil, biofuels, and synthetic fuels to become independent of OPEC imports by 2020," the report says.

It notes that domestic crude oil production is running higher now than at any point since 1997.

"Claims that very recent federal policies have had a significant role in the increase in domestic oil production are ... deeply misleading," the report says. "About 96 percent of the increase in domestic oil production is attributable to growth on state and private land."

Alaska has a great deal of federal land, and an expansive outer continental shelf.

To reach energy independence from OPEC, access to federal resources must be increased, Murkowski said. And more collaboration with Canada and Mexico is needed.

Among the steps she supports:

•Streamline and simplify the federal permitting process to ensure that offshore leases are developed in the Gulf of Mexico and elsewhere.

•Open the coastal plain of the Arctic National Wildlife Refuge to oil industry exploration and production. This should include "timely lease sales" and a 50-50 split of revenue between the federal government and the state.

•The National Petroleum Reserve Alaska "must be immediately placed into full availability for oil and natural gas leasing, consistent with its statutory designation. The reserve must be thoughtfully developed with roads, bridges, and pipeline facilities to promote broad onshore development of the diffuse resource base, while simultaneously accommodating the transportation of oil and natural gas from offshore fields in the Chukchi Sea to the Trans Alaska Pipeline System. 'Roadless' options for the NPR A should be expressly withdrawn from consideration."

Murkowski makes many other points in her report.

She disagrees with using the Strategic Petroleum Reserve, a stockpile of crude in Gulf Coast caverns, as a tool for temporarily relieving high retail gasoline prices. The oil should be held for true emergencies.

"Oil scarcity is a myth," the report says, noting the United States has not only billions of barrels of proved reserves, but vast quantities of shale oil and crude classified as "technically recoverable" or "undiscovered."

The report also says...

Better energy storage technologies are key to the future of solar and wind.

Nuclear energy "must remain a viable contributor to America's power supply."

Tax increases on fossil fuel producers "are ill advised, as higher taxes on a good or service will result in less of it — not more."

U.S. alternative fuels policies "have come to rely on burdensome mandates, inappropriate restrictions, and erratic subsidization." Yet alternative fuels hold great promise.

"From algal biofuels to natural gas and coal derived products, as well as combinations of these and other feedstocks, the potential options for diversification of our transportation sector's energy supply have perhaps never been greater."

The "Energy 20/20" report is posted online at bit.ly/Energy2020Doc. ●

Contact Wesley Loy at wloy@petroleumnews.com

● ENVIRONMENT & SAFETY

Canada lags behind resource boom

By GARY PARK
For Petroleum News

Canada's pace of natural resource development has been outstripping measures to protect the environment, the government's Environment and Sustainable Development Commissioner Scott Vaughan said Feb. 5.

In a series of audits that wraps up his five-year appointment, he was critical of the government's efforts to safeguard ecosystems from oil spills, the use of toxic chemicals and the rapid increase in hydraulic fracturing.

Vaughan said that "given the central role of natural resources in the Canadian economy, it is critical that environmental protection keeps pace with economic development. I am concerned by the gaps we found in the way federal programs related to natural resources are managed."

The findings coincide with a host of major developments, including expansion of Alberta oil sands production, greater use of hydraulic fracturing in shale oil and gas deposits and pipelines to support the export of bitumen and LNG to Asia.

Audit sees imbalance

He identified an imbalance between government financial incentives for the petroleum industry and what it is doing to protect the environment, noting that although the level of federal subsidies is declining, the Canadian government over the past four years has made more than C$500 million in direct grants for research and development and given C$1.47 billion in tax breaks, mainly involving accelerated write offs for oil sands producers.

But the government has failed to establish more protected marine areas even as offshore resource development proceeds, he said.

The audit also said the federal-provincial offshore petroleum boards in Newfoundland and Nova Scotia lack coordination in monitoring oil and gas activities and are "not systematically tracking measures to prevent or reduce environmental impacts."

Vaughan also urged the government to develop a better understanding of the risks associated with hydraulic fracturing given that the 200,000 fracking wells in Canada are expected to double in the next 20 years.

The audits were issued a week after Environment Minister Peter Kent said the government is on the verge of introducing "significant" changes to liabilities for offshore spills, which are currently C$40 million for the Beaufort Sea and C$30 million for the Atlantic Coast.

Government sources have said the liability cap could be raised to "billions of dollars" and that the industry would have to either buy insurance or self-insure. ●

Contact Gary Park through publisher@petroleumnews.com

● NATURAL GAS

Cook Inlet Energy gains gas security

Anchorage company reworks gas well on its Osprey platform to provide a cost-effective source of fuel for its oil field operations

By WESLEY LOY
For Petroleum News

Cook Inlet Energy LLC has cured its problem of securing affordable natural gas to fuel oil field operations.

The Anchorage-based company says it ran a successful test Jan. 26 on a recently recompleted gas well in its offshore Redoubt unit, then immediately put the well into production.

The RU-4A well, on the company's Osprey platform, tested at a peak flow rate of 1.7 million cubic feet of gas per day, a Jan. 30 press release said. The well taps the Lower Tyonek gas sands at a measured depth of about 9,200 feet.

"Based on log analysis and well test results, the average net pay is 11 feet with an aerial extent of 130 acres," the press release said. "Initial estimates of recoverable reserves by the company's geologists are in excess of 1 billion cubic feet of gas."

'Critical' need

The new production from the RU-4A well allowed Cook Inlet Energy to suspend purchases of gas supplies from third parties on Jan. 28.

The company had made establishing its own fuel gas supply a high priority due to a tight area gas market.

"We could clearly see that a secure supply of fuel gas was critical to keep operating costs down and to provide for security of supply," said David Hall, Cook Inlet Energy chief executive. "Therefore, we've concentrated on developing fuel gas supplies before executing our oil development program."

The company is working to restore production from shut-in and damaged oil wells on the Osprey platform, which the company and Miller acquired out of a bankruptcy sale in late 2009.

The Osprey platform is the newest and southernmost of the platforms in Cook Inlet.

Aside from the Redoubt unit, Cook Inlet Energy operates an assortment of other properties on the inlet's west side, including the West McArthur River oil field.

Cook Inlet Energy is a subsidiary of Tennessee-based, publicly traded Miller Energy Resources Inc.

> ***"In the last three months CIE's natural gas expenses have been approximately $450,000 per month."*** **—Miller Energy Resources**

Mounting costs

The Jan. 30 press release from Miller said: "In the last three months CIE's natural gas expenses have been approximately $450,000 per month. Declining gas supplies in the region have caused prices to increase significantly and have made it difficult to obtain contracts for the purchase of natural gas. The Cook Inlet lacks a spot market for natural gas, and all gas must be purchased under a contract. CIE's fuel gas acquisition costs reached $15 per thousand cubic feet this winter and were projected to increase over the winter months."

Aside from its Cook Inlet production, Miller Energy also has production in Tennessee.

The company, listed on the New York Stock Exchange, on Feb. 1 announced it had retained MZ Group as its investor relations adviser.

MZ Group will help tout what Miller's chief executive, Scott M. Boruff, called "a tremendous base of both producing and undeveloped assets in Alaska and Tennessee." ●

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ANS PRODUCTION

ExxonMobil subsidiary XTO, which averaged 2,197 bpd in December, up 5.4 percent from November.

North Slope

The BP Exploration (Alaska)-operated Prudhoe Bay field averaged 337,827 bpd in January, down 0.7 percent from a December average of 340,253 bpd. Prudhoe Bay includes satellite production from Aurora, Borealis, Midnight Sun, Orion and Polaris, as well as field production from Northstar and Milne Point.

The ConocoPhillips Alaska-operated Kuparuk River field averaged 131,197 bpd in January, down 1 percent from a December average of 132,526 bpd. Kuparuk includes satellite production from Tarn, Meltwater and West Sak, as well as field production from the Eni-operated Nikaitchuq field and the Pioneer Natural Resources Alaska-operated Oooguruk field.

AOGCC December data for Nikaitchuq shows 9,844 bpd, up 1.9 percent from November, and 6,270 bpd from Oooguruk, down 3.1 percent from November.

The BP-operated Endicott field averaged 10,923 bpd in January, up 0.8 percent from a December average of 10,837 bpd. Endicott volumes include the Savant Alaska-operated Badami field. AOGCC data shows Badami averaged 1,315 bpd in December, down 1.4 percent from November.

The BP-operated Lisburne field, which includes Niakuk and Point McIntyre production, averaged 30,499 bpd in January, up 5.4 percent from a December average of 28,949 bpd.

The ConocoPhillips-operated Alpine field averaged 66,513 bpd in January, down 4.4 percent from a December average of 69,584 bpd. Alpine includes satellite production from Fiord, Nanuq and Qannik.

ANS crude oil production peaked in 1988 at 2.1 million bpd; Cook Inlet crude oil production peaked in 1970 at more than 227,000 bpd.

—KRISTEN NELSON

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GOVERNMENT

Obama nominates Jewell as interior secretary

President Obama has nominated Sally Jewell, CEO of outdoor recreational equipment firm REI, as secretary of the Interior, to replace Ken Salazar, who announced in January that he would leave his position as Interior secretary after serving in the Obama administration for four years.

As Interior secretary Jewell will inherit a raft of difficult issues relating to government oil and gas development policies for federal lands in Alaska, including the National Petroleum Reserve-Alaska, the Arctic National Wildlife Refuge and the federal outer continental shelf.

As Interior secretary Jewell will inherit a raft of difficult issues relating to government oil and gas development policies for federal lands in Alaska, including the National Petroleum Reserve-Alaska, the Arctic National Wildlife Refuge and the federal outer continental shelf.

According to a statement from the White House Jewell has previously "worked in oil fields in Oklahoma and Colorado" and as an energy expert in banking.

And in announcing the nomination on Feb. 6, Obama said that Jewell is an expert on energy and climate issues.

"She is committed to building our nation-to-nation relationship with Indian Country," Obama said. "She knows the link between conservation and good jobs. She knows that there's no contradiction between being good stewards of the land and our economic progress; that in fact, those two things need to go hand in hand. She has shown that a company with more than $1 billion in sales can do the right thing for our planet."

With Congress yet to approve the Jewell nomination, Alaska's U.S. senators expressed interest in learning more about the president's nominee.

"So many of the decisions made by the Interior secretary have a profound impact on Alaska, and other western states," said Sen. Lisa Murkowski. "I look forward to hearing about the qualifications Ms. Jewell has that make her a suitable candidate to run such an important agency, and how she plans to restore balance to the Interior Department."

"While I am pleased the president moved quickly to fill this critical post, I think there is more we need to learn about Sally Jewell and what this decision means for Alaska," said Sen. Mark Begich. "The Department of Interior has enormous influence over Alaska's land, resources and its relationship with our state's First Peoples."

—ALAN BAILEY

● PIPELINES & DOWNSTREAM

Going public with a 'critical issue'

By GARY PARK
For Petroleum News

Enbridge and Kinder Morgan are emerging from years in the shadows to make a public case for their plans to ship bitumen from the Alberta oil sands to Asia.

For Enbridge, the Northern Gateway project is Plan A and, for that matter, Plan B, the company's Chief Executive Officer Al Monaco told a meeting of business and government leaders in Edmonton, emphasizing that his company has no alternative proposal.

He said the project, which includes shipping 525,000 barrels per day to Asia and U.S. West Coast refineries, has become a national priority if Canada is to overcome the current slump in prices for its crude.

"There is no more critical issue facing Canada today," Monaco said.

"Failure to develop a consensus around energy development will have serious consequences for this generation and generations to come," he said, estimating the price gap between U.S. and Canadian crudes is costing governments and companies about C$75 million a day.

'Sense of urgency'

On the same day Monaco was delivering his message, Kinder Morgan's Canadian President Ian Anderson was telling analysts in Houston that "there is a significant sense of urgency throughout Canada to access and tap into (the Asian) market" at a time when producers in Russia, Saudi Arabia, North Africa and Venezuela are all competing for a share of the Chinese market.

Kinder Morgan's hopes are pinned on expanding its Trans Mountain pipeline to 890,000 bpd by 2017 from the current 300,000 bpd, taking advantage of binding commitments from 13 companies to cover 708,000 bpd of those volumes.

The long-term contracts have prompted Kinder Morgan to build an additional 1.2 million barrels of storage at Trans Mountain's Edmonton terminal boosting capacity there to 9.4 million barrels.

The $5.9 billion Trans Mountain expansion is primarily targeted at increasing tanker traffic from the Westridge dock in Port Metro Vancouver to 30-34 tankers per month from the current five to six vessels, the likely trigger for heated community opposition. Some of the additional volumes would also be destined for refineries in Washington state's Puget Sound.

Monaco said that with "so much at stake, this is no time to be standing on the sidelines," conceding that Enbridge and Trans Canada had failed to appreciate that their Northern Gateway and Keystone XL projects had such potential to be lightning rods for "conflict and protest."

He admitted Enbridge should have been better prepared by reaching out earlier to affected communities and doing a "lot more ground work in terms of building trust."

Monaco said opponents of the pipelines have figured out that by stopping pipelines they also achieve their objective of stopping energy development.

He said industry's answer is to "build effective coalitions" by drawing on governments, service providers, labor unions and people "within communities that we operate in." ●

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GIESSEL

was repeated over and over was you've got the most complex tax regime in the world and it's frankly off-putting to companies who are looking at it and say I'm not sure we understand this, how can we invest here? So simplification is important. I sure would like this to be a bill, a tax regime, that's durable. It adapts to the different kinds of hydrocarbons we have on the slope. So we don't have to be coming back and tweaking it all the time. It is going to accommodate heavy oil, shale, viscous. This bill has some very creative elements in it that will do that.

Petroleum News: Are there any elements that you see that need tweaking?

Giessel: Well we have a loss carry forward for the companies, and that gains value as they hold onto it, and it gains value at 15 percent a year. As I look at that I understand Australia actually offers 20 percent. But how is 15 percent arrived at? Is it too high? You know inflation rate is 3 percent. That's a piece I'd like to look at and perhaps modify, but I don't know enough about that yet. That will be a discussion, a question I'll ask in committee. Our committee is going to focus on the resource issues, that is, what it takes to get our hydrocarbons out of the ground and into the pipeline and revenue for the state. The really deep dive on the fiscal elements will be left to Finance, but some of these we'll be looking at in Resources simply because you can't separate fiscals from the oil and gas itself.

Petroleum News: What about the criticisms that this is simply going to get pushed through?

Giessel: Well on the Senate side we've got three committees looking at it. In my committee we have scheduled long meetings going into the evening to hear this bill thoroughly and allow multiple opportunities for public input. I plan to hear it thoroughly. At the same time, because it's already been seen in TAPS Throughput and I've got some of the same members in Resources, we are not going to spend months looking at it, but it will be a thorough hearing.

Petroleum News: On to natural gas, what are your thoughts on the general status of the state advancing a pipeline project?

Giessel: I really like what the Alaska Stand Alone Pipeline has been doing, that's being headed up by AGDC (Alaska Gasline Development Corp.). They have looked at the fiscals and altered them. Now they are going to be transporting dry gas. It lowers the tariff. It lowers the cost to communities, but also because it's dry gas, it will allow multiple take off points. So I really appreciate the work they have been doing, not just locking into that initial plan, but being nimble and critical of their own plan and revising it to the best possible project.

So I really like what they are doing. At the same time, I really appreciate what the governor is doing by kind of pushing the three producers and TransCanada to tell us exactly what they're planning to do. Give us some of the precise elements. He keeps pushing them on that, so it's a good thing.

Petroleum News: What are your thoughts on the prospects on an LNG export market and following that, do you think Alaska should be lumped in with the Lower 48 on LNG export debate?

Giessel: First of all, Alaska should be the exception on any restrictions for export. We are not like the Lower 48 states. We are an island economy. We have to be able to export our resources. I actually have met some of the gentlemen from Japan who are interested in our natural gas. South Korea is interested in our natural gas. I've heard it said that China is interested. Bravo. I believe the market is out there. But we also have a potential in-state for industrial users. Donlin Creek has also surveyed in the potential for a natural gas pipeline to tidewater to power that mine.

My understanding is the communities around that mine are saying we don't want you barging in fuel oil. It's too much traffic on our rivers. Find a way to get natural gas so that's what they've done. International Tower Hill in Livengood, another massive gold deposit, these mine projects are very energy intensive. There's another potential industrial user.

These are just a couple that come to mind right off the bat, so I believe we've got the industrial users in the state. We've got the Agrium plant in Nikiski that could potentially be restarted. We've got refineries that can't get natural gas now because we don't have enough. I believe the markets are there.

I'm excited about our future, but then having been born here before statehood, I've seen what our oil and gas potential has done for our state. I tell people I used to think asparagus and spinach were supposed to be kind of gray and mushy because that's how it came out of the can. We didn't have Fred Meyer and Carrs and fresh vegetables and fruit. We've changed a lot and it's because of our resource development, so I'm very optimistic about our future, but it requires us to make those courageous decisions now. We can't keep waiting and studying and hoping that something is going to come over the horizon. We've got to seize the day. ●

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Petroleum news

Oil Patch Bits

ASRC'S Ty Hardt sets sights on top of the world

Arctic Slope Regional Corp. said Jan. 14 that in late March, its director of communications, Ty Hardt, will head to Kathmandu and attempt a climb of Mount Everest, the tallest mountain on Earth at an elevation of 29,035 feet. Identifying a need for the children of the North Slope, Hardt is using the climb to raise money for the Boys & Girls Club of Barrow, as well as other clubs statewide.

"I've been fortunate to be able to climb other big mountains around the world, but Himalayan expeditions present another level of difficulty, both in the amount of training and logistics," said Hardt. "I'm working hard to make sure I'm up to the challenge of Mount Everest, and am very excited to get this under way."

COURTESY ASRC

The Boys & Girls Club of Barrow is located inside Ipalook Elementary School and has more than 130 members, out of the more than 800 kids from Ipalook and Eben Hopson Middle School. "Our mission has always been to help enable our young people, and this unique fundraising effort will help us to extend our reach," said Alana Humphrey, CEO of Boys & Girls Clubs Alaska. "We will be following Ty on every step of his Mt. Everest expedition, and wish him the very best."

The expedition and fundraising effort is being called Going to Extremes. You can find more information regarding the climb at: www.g2extremes.com.

Carlile opens employee health clinic in Anchorage

Carlile Transportation Systems said Jan. 16 that it is very excited to announce the opening of its very own employee health clinic. The Carlile Employee Clinic is located on the Alaska Regional Campus at 2751 DeBarr Road and is managed by H2U.

The clinic partnership with Alaska Regional is designed to make it easier for employees to get well, stay healthy and is dedicated to serving Carlile employees and their families who participate in the company health plan. Employees will receive personalized atten-

see **OIL PATCH BITS** *page 17*

Companies involved in Alaska and northern Canada's oil and gas industry

All of the companies listed above advertise on a regular basis with Petroleum News

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TAX DISCUSSIONS

PFC Energy is back for the second year, hired to advise the Alaska Legislature in oil tax change discussions.

Mayer also noted that production and price are related, as more projects will be economic — increasing production — in a period of sustained high oil prices, and conversely, in a period of sustained low prices fewer projects will be economic, decreasing production.

Current production decline is some 6 percent a year and to hold revenue flat that decline rate under the SB 21 proposal would need to drop to 1 percent, he said.

Because it removes progressivity, the governor's proposal in SB 21 is slightly regressive — the state's share of revenue drops somewhat as oil prices rise.

Mayer said PFC Energy was asked to look at what it would take to remove that regressivity. By adding back 0.1 percent progressivity, to a maximum 35 percent production tax, the state's take would remain flat with rising prices. That 0.1 percent progressivity would also reduce the production decline level required to keep revenues constant from 1 percent to 2 percent.

The tinkering issue

The focus of PFC's presentation was on how competitive Alaska is under the current fiscal system, compared to how competitive it could be under the changes proposed by the governor.

There is, however, another issue: Alaska, like Alberta, is perceived in the oil and gas industry as a jurisdiction that tinkers with its tax system and tries to micro manage.

That, PFC Energy told the committee, makes investment decisions difficult for companies.

Mayer said Alberta is characterized as having high sovereign risk because it frequently changes its oil and gas fiscal terms. The province also is seen as pulling levers in the system to attempt to manage at the micro level.

Both of those characterizations absolutely apply to Alaska, especially over the last several years, Mayer said.

In addition to instability due to fiscal system changes, the state has tended to take an approach based on pulling specific levers, he said, citing the tax credit provided for the first jack-up in Cook Inlet as an example of pulling micro levers in the fiscal system.

Changing project economics

Companies want stability when making large capital investments with long payout periods, Mayer said. He said he could think of no better example of lack of fiscal stability in Alaska than Pioneer Natural Resources' experience with its North Slope Oooguruk field.

The discovery and investment decision were made under ELF, Mayer said. That is the state's former gross production tax, including an economic limit factor, hence the acronym ELF.

Oooguruk was challenged under ELF, Mayer said. (Pioneer applied for and received royalty relief for some of the leases in the project in 2005.) Although Oooguruk was a high-cost challenged project with a lot of issues, Pioneer sanctioned the project, he said.

That was in early 2006.

In the fall of 2006, during project development, the state passed PPT, the Petroleum Profits Tax, and by the time the field came into production in mid-2008, ACES or Alaska's Clear and Equitable Share had been enacted.

The project economics were much, much more challenging under ACES than they were under ELF when the project was started, Mayer said.

Lots of potential

Reinsch told committee members that industry sees a lot of potential in Alaska, but it is a very difficult operating environment and entry is difficult because there isn't a lot of what he called "asset churn" with companies selling producing properties.

Offshore prospects are going to be very challenged, Reinsch said, citing Shell's difficulties as an example. There is the question, he said, whether the technology is there to exploit the resource.

So while the state has many opportunities, Reinsch said he had yet to meet the oil and gas team that prefers chaos to stability when they are making multiyear investment decisions.

Minimizing tinkering

Committee Co-Chair Mike Dunleavy asked if there were areas with minimum tinkering where companies are active.

Mayer said there were many examples, and cited two: the U.S. federal system and Australia.

There have been changes, he said, but both are systems with simple straightforward rules leaving private sector companies to compete within the system.

The Australia federal system is profit based, but the level of government take is the same at any price range, isn't different for different types of projects and makes sure taxes are at a level to make the overall system competitive.

The U.S. federal offshore system is very regressive, with a fixed royalty, Mayer said, but is all about shedding risk from the government. Whereas typically signing bonuses, what a company pays for its leases, are so relatively small that PFC Energy doesn't even model them, in the federal offshore those bonuses are very substantial, he said, substantial enough to impact project economics.

The federal offshore system takes risk from the public sector and puts it on the private sector, but at high oil prices the private sector can make very high returns.

Characteristics of both systems include long-term stability and an avoidance of micro managing, he said.

Co-Chair Peter Micciche wanted to know why economics are better in Texas than in Alaska, and Mayer said it's a combination of a substantially lower cost of drilling in Texas and a substantially lower government take which produce better economics in Texas. Alaska, he said, has the burden of increasingly high costs.

The major players

In a review of the portfolios of Alaska's major players — BP, ConocoPhillips and ExxonMobil — Reinsch said all have faced major strategic challenges in the last few years: BP following the Macondo well disaster in the Gulf of Mexico; ConocoPhillips following its 2010 commitment to restructuring, a significant divestiture of assets and splitting the company; and ExxonMobil because of the challenge of replacing large international projects and its acquisition of XTO, which he described as almost the last play standing of material impact for ExxonMobil. XTO's play type, however, isn't one that makes sense for ExxonMobil, he said. They're efficiency experts, Reinsch said, and are now into the treadmill game of drilling thousands of wells.

PFC Energy categorizes Alaska as a harvest area for both BP and ExxonMobil, but as a core area for ConocoPhillips.

Sen. Berta Gardner, the committee's sole Democrat, asked if harvest mode didn't mean that companies would simply take any monies from tax reductions and invest them elsewhere, to which Reinsch responded that, all things being equal, a better fiscal environment was positive for investment in an area.

Initial company reactions

The governor's proposal removes progressivity but also removes the 20 percent capital credit which was placed in ACES as a balance for progressivity.

In industry reactions on Feb. 5 — from the Alaska Oil and Gas Association, AOGA, and ConocoPhillips Alaska, the North

see **TAX DISCUSSIONS** *page 19*

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OIL PATCH BITS

tion, quality care; spend less time in waiting rooms and save money with free office visits.

Board certified nurse practitioners will care for employees with common illnesses such as allergies, ear infections, strep throat, minor infections and rashes. Additional services include blood pressure checks, flu diagnoses, x-rays, lab work and the administration of various vaccines. As an added convenience, employees can have prescriptions written by the nurse practitioner filled right at the clinic.

In addition to having an easy-to-access location, the clinic's hours were chosen with the employees' needs in mind. The clinic's operating hours are Monday through Friday with extended hours on Thursday. "We welcome Carlile Transportation Systems employees and dependents to our campus, and look forward to sharing the convenience of our clinic services with them," said Annie Holt, CEO Alaska Regional Hospital.

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 March.

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PORT SITES

accommodating deep-draft vessels. At present, no such harbor exists.

The 77-page report doesn't include cost estimates. It recommends public agencies and banks or other private entities collaborate on funding and construction.

Vast area studied

"The Arctic is changing," says the report forward. "Diminishing sea ice and expanded natural resource extraction are happening now. From drilling in the Chukchi Sea, dredging for gold in Nome, to ore and gas concentrate tankers coming over the top from Europe, Alaska is experiencing more and more traffic past its shores. Alaska's western and northern coastline is mostly shallow with very little marine infrastructure. Coast Guard and other support vessels may be many days of ship travel away. Proper planning and responsible development is important to Alaska's future."

The study considered marine infrastructure needs over a vast area, from the Southwest Alaska village of Bethel west and north then east to the Canadian border. That's more than 3,000 miles of coastline, or one and a half times the length of the eastern U.S. coast from Canada to the tip of Florida.

Aside from the recommendations to "invest strategically" in an "Arctic ports system," including "deep-draft solutions," and to focus feasibility work on Nome and Port Clarence, the report makes several other suggestions:

*Make the Army Corps the lead federal agency for permitting, design and construction of the deep-draft port system.

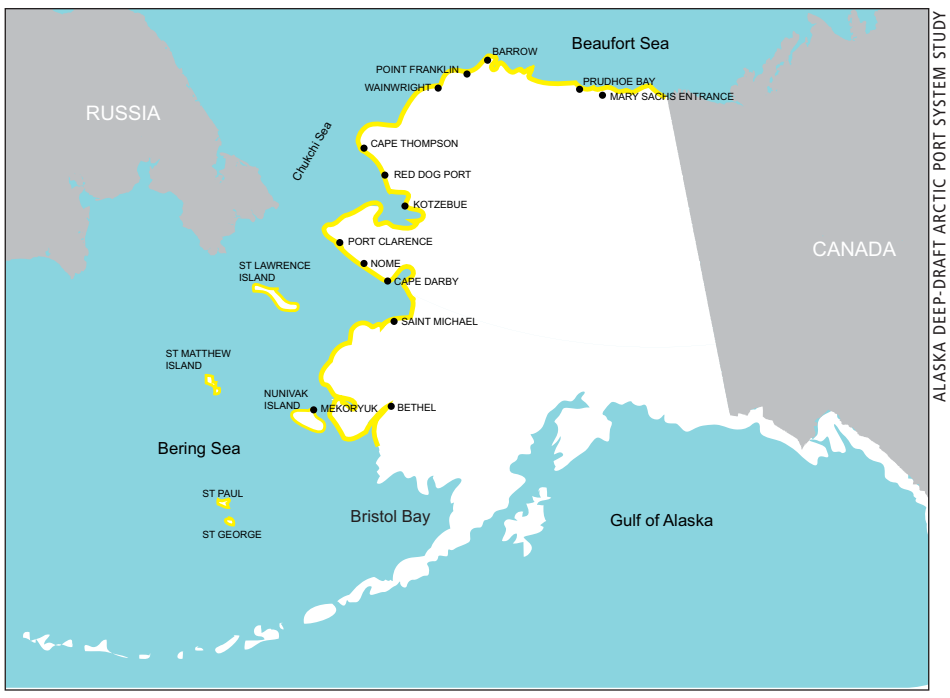
*Use public-private partnerships, known as P3s.

*Increase funding to the National Oceanic and Atmospheric Administration and other agencies for hydrographic and bathymetric mapping to support marine infrastructure development.

*Explore and develop navigational aids such as ship routing, vessel tracking and traffic separation.

The report defines a deep-draft port as one that can accommodate large vessels such as cargo ships. It should have water depth greater than 35 feet.

Alaska has deep-draft ports in such locations as Anchorage, Valdez, Kodiak and Unalaska, but none along the Arctic coastline.



Sites considered

The study team considered several potential port sites, some actually on the Arctic Ocean coastline and some to the south in the Bering Sea.

The "candidate sites" were: St. Paul Island, St. Lawrence Island, Nome, Port Clarence/Teller, Kotzebue/Cape Blossom, Mekoryuk, Cape Thompson, Wainwright, Point Franklin, Barrow, Prudhoe Bay, Mary Sachs Entrance, Bethel and Cape Darby.

The primary site evaluation criteria were proximity to oil and gas and mining activity, intermodal connections, upland support, natural water depth and navigation accessibility.

The team whittled the candidates to a shortlist of four sites: Nome, Port Clarence, Cape Darby and Barrow.

From there, the team recommended two, Nome and Port Clarence, for feasibility analysis considering, among other things, "alignment with potential investors." The study says the two top-ranked sites will be the focus of feasibility work for 2013-14.

Nome's proximity to oil and gas activity and mining operations, along with its upland support, make the city "an attractive choice for deep-draft operations," the study says.

Nome is a small Bering Sea city on the south coast of the Seward Peninsula, about 100 miles south of the Arctic Circle. Although it is a regional trade center, Nome is disconnected from the state's road system. It already has a medium-draft port, and is seeking to expand an existing causeway and related breakwater to accommodate deep-draft vessels, the report says.

Port Clarence, 67 miles northwest of Nome, is a former Coast Guard Loran station. The village of Teller is nearby.

"The natural protection offered within Port Clarence and its proximity to Bering Strait has led to the use of this natural harbor since whaling vessels were active in the region in the 1860s," the study says. "It is currently used by barge operators as they await ice retreat north of Bering Strait each summer."

Nome-based Bering Straits Native Corp. has been working with a marine transport company, Crowley Maritime, on a deep-water port development plan for Port Clarence, the study says. The port facilities would be designed to support offshore oil and gas operations.

Lots of planning under way

Notable sites that didn't make the shortlist for deep-draft port feasibility analysis include the villages of Barrow and Kotzebue, as well as Prudhoe Bay, epicenter of the North Slope oil industry.

Barrow, a large and well-equipped village, is about midway between active oil and gas exploration targets in the Beaufort and Chukchi seas. At present, Barrow has no protected harbor.

At Prudhoe Bay, a causeway and dock system services barges that transport drilling and production equipment to the North Slope.

Kotzebue is another major village that supports the large Red Dog zinc mine. Kotzebue currently has a shallow-draft port.

The city of Kotzebue is pursuing a 10-mile road and deep-water port at nearby Cape Blossom, the report says. The state Department of Transportation is expected to start construction of the $30 million road from Kotzebue to Cape Blossom in 2014, and the city's mayor said "expressions of interest" have been received for liquefied natural gas and copper export, the report says.

The big challenge in siting a deep-draft port for the Arctic is the generally shallow nature of the region's coastal waters.

Cape Darby, another site on the Seward Peninsula, southeast of Nome, is "one of the very few naturally deep-water ports in the study area," the report says. Cape Darby potentially could serve as a deep-draft port for resource export, but no community or infrastructure is there.

Another site, Cape Thompson on the Chukchi Sea about 26 miles southeast of Point Hope, also holds some appeal. The report says Barrow-based Arctic Slope Regional Corp. and a state agency, the Alaska Industrial Development and Export Authority, are interested in the site as a terminal for coal exports, and possibly as a Coast Guard hub.

"Cape Thompson gained notoriety in 1958 as the proposed site for an artificial harbor to be dug by nuclear bombs known as 'Project Chariot,'" the report says. "The proposal was never implemented."

'Wild West' or 'Golden Days'

An Arctic port would serve more than industry.

"Navy, Coast Guard, NOAA and other research vessels are traveling the northern waters with little or no infrastructure support," the report says. "The agencies have each expressed interest in utilizing a deep-draft port and enhanced port facilities, but they lack funding and authority to build such infrastructure. Long-term federal leases could provide a partnership opportunity."

The report sketches out a number of possible scenarios "to examine the uncertainties of what lies ahead."

The study team facilitated a scenario work session in July 2012 with more than 20 Arctic experts and stakeholders, with an outlook to 2060.

Under what the report calls a "Wild West" scenario, high demand for resources creates an "undisciplined world of boom and bust with everyone for himself."

"The Wild West scenario could result in numbers of isolated single-purpose ports led by private investment," the study says. "There would be no regional or state port authorities. Siting would be driven by independent business agendas and resource proximity. Public and private investment would not be coordinated. This scenario would not yield a highly functioning Alaska Arctic port system."

A more favorable scenario, called "Golden Days," would see collaboration in an environment of high and sustained resources prices.

"The Golden Days scenario could result in a number of regional port authorities, or even a statewide port authority to manage the high level of port operations in the Arctic," the study says.

The draft study is posted at 1.usa.gov/12ghRFE. Comments may be submitted to AKRegPorts@usace.army.mil until Feb. 28. ●

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KULLUK PROBE

will require repair following the New Year's Eve grounding incident, he said.

"It is too early to say how this will impact the (the program) going forward," Voser said, referencing the Kulluk grounding. "We need to wait for the investigations which some external bodies are doing, but we also internally assess the risks and the learnings and then actually lay out our plans for the years to come."

The Kulluk ran aground to the south of Kodiak Island on the evening of Dec. 31 and was refloated on Jan.6, before being towed to a safe anchorage on the following day.

Shell Chief Financial Officer Simon Henry said that Shell had provided for $40 million in Kulluk salvage costs in the last quarter of 2012. The company anticipates another $50 million in Kulluk related costs in early 2013, including costs incurred by the U.S. Coast Guard and the costs of using Shell's contracted vessels. But none of these costs include the eventual bill for repairing the Kulluk — that cost is not yet known, Henry said.

Voser vehemently denied a story that has been doing the rounds, that Shell moved the Kulluk south to avoid taxes in Alaska.

So far Shell has spent about $5 billion on its Alaska program, including a spend of about $1 billion in 2012, Voser said.

Voser vehemently denied a story that has been doing the rounds, that Shell moved the Kulluk south to avoid taxes in Alaska.

"This played no factor in the decision to move the Kulluk," he said. "We had to move the Kulluk to a safe, bigger harbor to do the repairs."

The tax avoidance story had resulted from a statement by a Shell employee being taken out of context, Voser said.

Alaska challenges

Asked whether the grounding of the Kulluk in a severe storm demonstrated the type of challenge that operating in the Alaska offshore presents, Voser said that while harsh weather is a factor in Alaska, it is also a factor in many other parts of the world.

"We are actually used to dealing with that," Voser said, citing a recent situation in Australia where the company had been forced to mobilize and demobilize a rig crew three times because of typhoons.

All businesses have to manage risks, he said.

"I can never say that there will never be an incident," Voser said. "That's just not going to work."

Asked whether Shell might leave Alaska in the fallout from the grounding of the Kulluk and the ensuing investigations into the company's Alaska operations, Voser said that responsible operators like Shell, who are prepared to spend significant sums of money to prepare for drilling, are needed for development in the Arctic, a region with huge undiscovered resources.

"This is an area where we see the Shell strengths actually playing and, therefore, in the longer term we want to develop in the Arctic," Voser said. ●

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TAX DISCUSSIONS

Slope's largest producer, the committee was told that removing progressivity was a positive, but removing the credits was a negative.

Kara Moriarty, the executive director of AOGA, said the organization's members supported elimination of progressivity but were concerned with how the bill addressed tax credits. She said AOGA supported gross revenue exclusions (a 20 percent tax allowance for new oil, either from new units or new participating areas within existing units), but said the concept should be expanded to fit projects in legacy fields.

Bob Heinrich, vice president of finance for ConocoPhillips Alaska, and Scott Jepsen, the company's vice president of external affairs, said the governor's proposal would improve Alaska's business climate and make the state more competitive at oil prices above $100 a barrel but didn't do enough to encourage investment in legacy fields and didn't encourage investment at lower oil prices.

Jepsen said the potential for additional oil production lies in the state's legacy fields, and said taxes, along with high operating costs, are a problem for Alaska in attracting investment. He recommended eliminating progressivity and keeping the credits provided under ACES.

Heinrich said that of the billion dollars in credits frequently cited, less than half goes to producers, more than half to explorers. He also said cash margins for ConocoPhillips are "significantly less" in Alaska than in new projects in which the company is investing in the Lower 48 and said it is difficult to compare the company's earnings in Alaska with those in the Lower 48, because in Alaska 90 percent of the company's production is oil, whereas in the Lower 48 more than 70 percent of its production is gas and gas liquids, subject to current very low gas prices.

On a barrel of oil equivalent, which includes natural gas and natural gas liquids, there is higher net income per barrel in Alaska, he said, but not on an oil-to-oil comparison basis.

SB 21 impact at low prices

The high Alaska tax rate impacts overall investment decisions, with ACES impacting cash flow in the long term, Jepsen said. He said Alaska is impaired in comparison to other investment opportunities because of the portion of profit taken in taxes and is just not able to attract discretionary cash for investments.

The "easy oil" on the North Slope is gone and what remains is challenged oil with complex, high-cost wells, smaller reserve targets, isolated fault blocks, satellites and viscous oil, Jepsen said.

Heinrich said that the proposed changes under SB 21 would increase the tax at lower oil prices, less than $93, and said that with high operating costs in Alaska, it doesn't tilt the equation enough.

While SB 21 would make Alaska more competitive at prices above $100, that isn't ConocoPhillips' perspective on the price outlook, Heinrich said.

Jepsen noted that the potential for increased production lies primarily in legacy fields, and Heinrich said the gross revenue exclusion should be extended to legacy fields.

—KRISTEN NELSON

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LNG TERMS

And his message to them it that "substantial (LNG) prices" are needed to underpin multi-billion dollar export schemes that include the high cost of developing resources in northeastern British Columbia, building pipelines and completing liquefaction and tanker terminals on the British Columbia coast.

Similar challenges have seen the cost of new Australian projects get caught in an inflationary spiral.

U.S. projects on the other hand have the advantage of existing gas pipeline networks and existing import terminals that can be easily converted to exports.

"I can tell you it takes a large capital commitment and most companies in the world aren't going to make that commitment without having pricing that gives them a fair return. That pricing is going to need to be something close to oil parity, or the projects won't get built," Watson told analysts.

"What we see is continuing growth in (LNG) demand. There's a lot of gas out there, but pulling these projects together and getting them online ... in time to meet that demand, is a different matter."

He declined to discuss a possible timeline for Kitimat LNG until a sales agreement is negotiated. "We hope to close the transaction soon."

Push by Asian utilities

Chevron's entry into Western Canada coincides with a push by Asian utilities to link LNG sales to North American gas prices.

"You've got this trend of Henry Hub indexation, which is perceived to be a lower level of pricing, creeping into the expectations of Asian buyers nowadays in an attempt to squeeze seller margins," said Asish Mohanty, an LNG analyst with energy consultant Wood Mackenzie.

Some of those objectives were bolstered last summer when Cheniere Energy, operator of the Sabine Pass LNG project, signed contracts that require offtakers to pay 115 percent of Henry Hub gas prices, plus US$2.25-$3 per million British thermal units to cover the costs of liquefaction.

Most existing LNG deals are linked to oil, usually Brent prices, making the price about 14-15 percent of the price of a barrel of Brent, although some older sales contracts are as low as 13 percent of Brent.

Although somewhat late on the scene, Chevron is seen as bringing heft to the Kitimat project, which already holds the only large-scale export permit from Canada's National Energy Board, covering 10 million metric tons per year.

Tom Valentine, a partner in the law firm of Norton Rose Canada that played an advisory role in the Kitimat transaction, said that "if you look around the world there is only a handful of companies that can legitimately say they are world leaders in the LNG space. Chevron would be one of them." ●

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INTERIOR LNG

three components: a $50 million General Fund allocation to AIDEA, $125 million in AIDEA loans through the Sustainable Energy Transmission and Supply fund and authorization for AIDEA to issue up to $150 million in bonds.

Under the financial outline it presented to lawmakers, AIDEA would help a third party partner pay for the roughly $220 million North Slope LNG plant using the $50 million grant, the $125 million in SETS loans issued at 3 percent interest and a $15 million storage credit already on the books with the remainder coming from the private sector.

"We need SB 23 as a tool to work with the private sector," Davis said.

Of the 16 responses AIDEA received to its late December request for interest in the project, several came from banks, private equity groups and financial consortiums, Davis said, including Guggenheim Partners, KeyBanc Capital Markets and Northrim Bank.

Local distribution needed

The $150 million in bonding, which AIDEA also expects to issue at 3 percent interest, would go to expand the local distribution system through the high and medium density population centers and to major industrial users in the Interior. Although Fairbanks Natural Gas LLC currently operates a small grid serving some 1,100 customers in Fairbanks, the vast majority of businesses and homeowners in the city rely on fuel oil or wood for space heating, and the Fairbanks Natural Gas certificate only covers the city proper, without reaching the surrounding rural areas or the nearby city of North Pole.

AIDEA expects the two sides of this "first phase" to cost about $400 million.

Because the private sector is unlikely to fund an LNG plant without guaranteed customers and unlikely to fund a distribution expansion without a gas supply, the Parnell administration believes the financial package is the best way to kick-start the project.

"Both the demand side and the production side have to be financed almost in tandem for this to really work. ... This plant will allow you the ability to start building out that distribution system," AIDEA Executive Director Ted Leonard told the Senate committee.

Once the system is in place, AIDEA believes the Interior could see another $400 million to $600 million in private investment to expand the grid into lower-density corners of the region. Davis compared it to a bank being skeptical about offering an initial mortgage, but willing to offer refinancing once the homeowner establishes a positive track record.

And because the distribution grid will also be necessary should Alaska get a large-diameter gas pipeline, or a smaller in state pipeline, AIDEA sees it as a good investment.

Questions remain

While Interior lawmakers are eager for the project, both to alleviate the cost of heating and to improve air quality, some Southcentral lawmakers have expressed skepticism.

AIDEA currently envisions a 9 billion cubic feet per year plant that could be scaled up to 20 billion cubic feet if demand warrants, but Sen. Peter Micciche, a Republican from Kenai, warned against touting the benefits of a larger plant. While a larger plant would lower the wholesale cost of gas, "the rest of this system does not benefit from scale."

Unlike a pipeline, trucking comes with fixed labor and transportation costs, he said.

And while AIDEA is presenting a $400 million cost estimate, Micciche believes lawmakers still have "a lot to learn" about the project before they can be confident in the price tag. He pointed specifically to the cost to remove propane from gas on the North Slope, and the cost to move the plant should a future pipeline render it obsolete.

While acknowledging AIDEA can only give a rough estimate for the project until it goes through the responses in detail, Davis noted that the bill before lawmakers would only give AIDEA the ability to move forward, and decide whether to sanction the project.

In addition to questions about the accuracy of cost estimates, Sen. Bill Wielechowski, a Democrat from Anchorage, wanted to know about the likelihood of bringing excess LNG to supply-constrained Southcentral, and made "a pitch" for those hypothetical supplies to be priced on a postage stamp rate — meaning all end users would pay the same price.

And although AIDEA expects the plant to someday be replaced by a gas pipeline, Wielechowski wanted to know what would happen if the plant and the distribution grid were instead replaced by electric power from the proposed Susitna-Watana Dam.

In a cautionary note, Sen. Click Bishop, a Fairbanks Republican, recalled how Interior residents bet money on the proposed Rampart Dam of the Yukon River in the 1950s, only to have the project never come to pass. And Sen. John Coghill, a North Pole Republican, said Interior residents needed cheaper energy long before the 2025 start date of the dam.

What about HCCP?

And what about an infamous AIDEA energy plant of old?

At a Feb. 4 House Energy Committee hearing, Rep. Doug Isaacson, a North Pole Republican, asked about the "elephant in the room," the Healy Clean Coal Project, the $300 million AIDEA power plant built in the mid-1990s but offline since 2000.

The troubled facility, currently being sold to Golden Valley Electric Association, taught AIDEA some important lessons about "how to structure deals," Leonard said. Instead of owning facilities outright, "we should be in partnership with the private sector," he said.

This philosophy guided how AIDEA financed the Endeavour jack-up drilling rig, he said.

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