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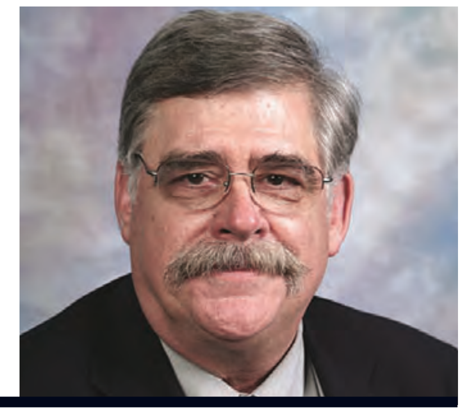

page 3 Olson sees inlet growth as model; says SB 21 needed for change

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JUDY PATRICK

The trans-Alaska pipeline

Declining oil flow in TAPS lowers North Slope NGL export limits

Although designed as a means of shipping crude oil from the North Slope to the Valdez Marine Terminal, and hence by tanker to market, the trans-Alaska pipeline also carries modest quantities of another material called natural gas liquids, or NGL, to add value to the export stream. But declining oil throughput in the pipeline also reduces the amount of NGL that the line can carry, Mike Malvick, senior process advisor with Alyeska Pipeline Service Co., explained to Petroleum News.

Essentially, NGL, being more volatile than crude oil, increases the vapor pressure in the line, thus potentially increasing the gaseous hydrocarbon emissions from crude oil relief tanks along the line. So, to ensure compliance with its Environmental Protection Agency air permits, Alyeska has to pose a vapor pressure limit of 14.2 pounds per square inch to the fluids delivered into the line at pump station 1 on the North Slope, Malvick said. And that vapor pressure limitation typically limits the NGL content to around 7 to 8 percent of the volume of fluids in the line: Reduce the rate of flow of oil, and the rate of flow of NGL also must drop.

The oil stream flowing from each of the five pipelines that deliver oil to pump station 1 from the various North Slope oil fields has to meet that 14.2-pounds-per-square-inch limitation, Malvick said.

see **NGL LIMITS** *page 11*

More Mackenzie project stirrings

If the Mackenzie Gas Project ever does go ahead it faces a new price tag of C$16.1 billion, up C$4.8 billion from its most recent estimate in 2007.

In filing that information with the National Energy Board, operator Imperial Oil and its partner ExxonMobil, ConocoPhillips Canada, Shell Canada and the Aboriginal Pipeline Group complied with its requirement to keep the federal regulator updated on the estimated costs of a Mackenzie Valley pipeline and a gas gathering system.

However, the figure does not include the cost of developing the anchor fields, which have been targeted for initial production of 823 million cubic feet per day, although the inclusion of other gas discoveries in the region could raise the volumes to 1.8 billion cubic feet per day.

At the same time, the proponents said they have yet to make a decision to start construction because of the prevailing gas market conditions.

Minister encouraged

But Northwest Territories Industry Minister David Ramsay is encouraged by the comments of Imperial Chief Executive Officer Rick Kruger in October that the company is exploring a possible revamp of the MGP that could see it tied into exports of LNG.

Ramsay told the Globe and Mail that move is a positive sign for the long term that the three Mackenzie Delta anchor fields — Taglu (Imperial), Parsons Lake (ConocoPhillips and

see **MAC STIRRINGS** *page 12*

NATURAL GAS

RCA chooses muni for gas

Interior Alaska Natural Gas Utility gets distribution certificate; FNG app rejected

By ERIC LIDJI
For Petroleum News

State regulators are allowing a new municipal utility to offer natural gas service to sections of the Fairbanks North Star Borough, and have rejected a similar application from Fairbanks Natural Gas LLC, the privately held distribution utility in the region.

The Regulatory Commission of Alaska has given the Interior Alaska Natural Gas Utility the go ahead to offer natural gas distribution throughout much of the borough, including the city of North Pole. The decision sets in motion the last mile of the Interior Energy Project, a state-backed effort to expand natural gas service to the Interior by late 2015.

The RCA said it made its decision "in the context of the entire project." With that in mind, the RCA said it denied the Fairbanks Natural Gas application because the utility "failed to demonstrate a viable build-out plan for the proposed expanded service area."

Specifically, according to the RCA, the Fairbanks Natural Gas application expected Golden Valley Electric Association to be a major customer, even though the regional electric cooperative "had no plan to be an industrial customer" of Fairbanks Natural Gas.

Trucking LNG

The Interior Energy Project hangs over the ruling.

The state agency managing the project, the Alaska Industrial Development and Export Authority, had tes-

see **INTERIOR GAS** *page 12*

NATURAL GAS

Wave of LNG exports

Approved Canadian volumes exceed current output; future supply, demand concerns

By GARY PARK
For Petroleum News

Canada's National Energy Board has approved a bundle of four LNG export permits, raising the total to seven and the natural gas equivalent to 14.68 billion cubic feet, bcf, per day, stirring the first sign of concern about the impact on domestic supply and demand.

The federal regulator, whose approvals face an automatic review by the Canadian government and final ratification by the federal cabinet, offered assurances that the gas resource base in Canada and in North America is "large and can accommodate reasonably foreseeable Canadian demand, LNG exports and potential increases in demand."

Concerns from IGCAA

But the Industrial Gas Consumers Association of Alberta, IGCAA, without formally opposing the newest applications, urged the NEB to "consider the aggregate impact of the LNG exports."

While expressing confidence in the NEB's observance of its mandate to ensure that the gas to be exported is surplus to Canadian requirements for the 25-year permit period, the IGCAA said it was concerned that overall impact of the license applications was not being considered.

The IGCAA submitted a table to the NEB that tallied the approved and proposed LNG export volumes, but the NEB said it did not find the data useful in

see **LNG EXPORTS** *page 11*

EXPLORATION & PRODUCTION

The power of EOR

Prudhoe recovery to reach 60 percent with techniques to push out more oil

By WESLEY LOY
For Petroleum News

BP is on track to recover an impressive 60 percent of the crude oil within Alaska's giant Prudhoe Bay field, says an article in the latest issue of the company's international magazine.

A key factor is BP's intensive use of enhanced oil recovery, or EOR, techniques.

EOR works to push or sweep more oil from porous rock formations. The techniques depend on a ready supply of natural gas, which Prudhoe is blessed to have in great abundance.

The article in BP Magazine, available online at tinyurl.com/or645a8, says the industry has three main ways to meet the world's growing demand for oil: making new discoveries, developing unconventional resources such as shale and oil sands, and enhancing recovery from existing fields.

EOR might lack the sex appeal of new discoveries or a shale oil boom. But it can make a huge contribution, the article says.

Keeping the pressure on

The article quotes a former president of the Society of Petroleum Engineers, Alain Labastie, who said the ultimate average recovery factor for oil fields worldwide is about 35 percent, meaning 65 percent remains stuck in the ground.

"If you drill a well into a reservoir and rely on natural pressure to force the oil to the surface, you

see **POWER OF EOR** *page 10*

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● GOVERNMENT

Kurt Olson sees inlet changes as model

Says SB 21 necessary to make state more competitive; cites changes in Cook Inlet, resulting growth in industry in that part of state

By STEVE QUINN
For Petroleum News

House Rep. Kurt Olson arrived in Juneau in 2005, just in time for spirited debates on oil taxes, an issue that prevails still today with an upcoming referendum to repeal the recently passed reform Senate Bill 21. He brings to the table some institutional knowledge about oil taxes, natural gas pipeline developments, be it the Stranded Gas Development Act or the Alaska Gasline Inducement Act, and recent uptick in his backyard Cook Inlet.

The Soldotna Republican says he's enjoying what's known in the Kenai region as The Stampede, reflecting the industry's rush to take advantage of tax breaks for various exploration.

Olson serves on the House Resources Committee and has been busy during the interim keeping up with Arctic policy development, progress at Point Thomson since the state and Exxon reached a development agreement, and Alberta with the Energy Council.

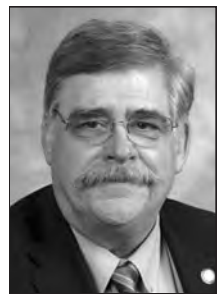
He discussed his views with Petroleum News.

Petroleum News: Let's start with your visit to Point Thomson. What were your impressions and takeaways?

Olson: Obviously it wasn't my first trip to the North Slope, but it was my first trip to Point Thomson, and I was really impressed with the work that's going on up there. They have the first portion of the camp finished. They have the foundations for the oil lines going about 30 miles. They hope to have the pipe on top of it hopefully by the end of the next construction season. The workforce will increase after the first of the year. They have drilled three holes up there and are getting ready to drill several more, I believe. So, I was really impressed with the work. The runway is incredible. The runway, considering the size, it's probably the best runway in the state. It was necessary and it's an incredible runway and airport operation for such a remote project.

Petroleum News: Was there ever a time when you thought the state and Exxon would never get to this juncture?

Olson: You know, I just hoped I would be around when it did. I figured ultimately we would get to it. It would be done when it made economic sense to all parties. It's common knowledge that Exxon is negotiating with the borough for some land on the Kenai Peninsula out by the LNG facility and they are also leasing office space in the Kenai area, so I don't believe they would be doing that if they weren't planning on following through.


REP. KURT OLSON

Petroleum News: You recently also went to Alberta for Energy Council. Tell me about that trip.

The place was booming. I believe the minimum wage now in Alberta is $20. It's not government mandated. It's what they are having to pay for entry level labor. The fast-food industry, gas stations, whatever. I know we would like to be in that position in the next few years.

We also learned Mexico wants to be in a position they haven't been in for decades. They nationalized the oil and gas industry years ago and ran off all of the names we are familiar with: BP, Exxon and any predecessor companies. What they have is a situation where they don't have state-of-the art equipment or new technology that the other parts of the world are using. At Energy Council, I believe that was the first place they announced they would be putting leases out to bid and they were going to be doing what most of the rest of the world is doing, having partnerships with the majors.

What it means is there could be cheaper oil in the next five or 10 years with more oil coming from that region, that part of the Gulf.

Petroleum News: Were there any other impressions from the Alberta trip?

Olson: I'm glad you asked. What's happening in Alberta is happening everyplace. I'm getting tired of legislators from North Dakota thanking me for the workforce we are supplying to North Dakota, and not only that the Alaska-based companies that are active down there and doing a superb job for them. I would rather hear them say, 'I wish we could get a workforce like you have in Alaska.' A good portion of them are now moving south. I don't know how many more years we can do that before people stop commuting back to Alaska during their time off and decide they are going to move down there.

Petroleum News: Moving on to other competitive issues, does that speak to the argument of keeping SB 21 in place?

Olson: I voted for it and will continue to support it. You and I were both around for PPT, ACES and AGIA and the whole game change on that where we had a number of different tax regimes in place but very little time in between to find out whether they were working or not working or taking too much. I spent, I'm guessing 10 days or two weeks having hearings in the House Oil and Gas Committee (in 2007), and it was incredible at that point and time.

We moved the (ACES) bill and when it hit the Senate, the taxes changed a bit — actually the progressivity amounts. Looking back as I recall, we had the models based on progressivity, I don't believe we used anything higher than $105 a barrel. It couldn't have been much higher than that. I don't think we ever contemplated that it would be up to $142 or $144 and the impact it would have on that.

It's obvious we are going to have to do something if we are going to be competitive. We saw Alberta do basically the same thing. It didn't take them long at all to figure out that everybody was leaving Alberta over the taxes. That had one disadvantage that we didn't have. It's a lot easier to leave Alberta than it is to leave Alaska. It takes longer here to demobilize and send equipment to North Dakota or wherever you are going to be able to work competitively.

Petroleum News: What do you like about SB 21?

Olson: I believe it's attempting to find a balance to where we can get the producers to invest more and to do more and at the same time have a much more reasonable tax income coming in. When you weigh the jobs and everything else into it, we are not losing as much money as people are putting out. What hurt us this time was No. 1 the decline in production and No. 2 the price came in below the estimates for the next year. I think we got hammered from several different directions at the same time.

Petroleum News: You've been around for PPT and ACES, and heard numerous presentations on tax regimes. Why is this still such a hot button topic eight to 10 years later?

Olson: Ultimately what it comes down to is we are still doing what we were upset about 10 years ago, changing the tax regime every couple of years, tweaking it and not having any continuity and having any fiscal stability. Fiscal certainty went out the window with the Murkowski administration but there has to be some sort of long-term regime in effect. If the producers know what it's going to be, for the most part they can work around it. If the project pencils out, it pencils out. I think they would be happy with fiscal stability. For the state it's the same way, too. At least it will be easier to do revenue forecasts.

Petroleum News: We keep hearing how repealing SB 21 would hurt advancement of a gas pipeline. How do you think SB 21 helps advance a gas line project?

Olson: By having fiscal stability. What we are seeing now is they can see this as adequate. I think there are people out there who would like to see the oil companies not make a profit. I'm not one of them. What I would like to see is if we took (Gov. Sarah) Palin's version before all of the manipulations of the progressivity — the original version of her bill — and how that would pencil out as compared to what we are doing now. The same with PPT. Get a handle on whether those were closer to hitting the sweet spot or if they were out of the picture, too. I'm not going to ask for it. I don't think it would be the best use of our money right now, especially if we don't have a lot. I would still be real curious, especially compared to Palin's original version because I have a feeling, it wouldn't look all that bad now, but that was before progressivity got spiked up.

see **OLSON Q&A** page 10

● EXPLORATION & PRODUCTION

Buccaneer eyeing West Eagle, Cosmo

The independent is delayed at West Eagle, waiting for permits at Cosmopolitan and preparing for a January hearing on Kenai Loop

By ERIC LIDJI
For Petroleum News

Buccaneer Energy Ltd. is making moves on three Cook Inlet projects as the year comes to a close, and claims to have leads on fixing a potential financing shortfall for its work.

The Australian independent is poised to spud the West Eagle No. 1 well, is permitting the Cosmopolitan No. 2 well and is touting numbers for its Kenai Loop field. The company also said it is talking to "multiple parties" about farming-out or selling certain assets.

The Glacier No. 1 drilling rig is currently on location at the West Eagle unit, according to Buccaneer. The company missed a Dec. 1 deadline to spud the well and is now aiming for a Jan. 31, 2014, deadline for completing the well. The West Eagle unit agreement required Buccaneer to post two $600,000 bonds with the Alaska Department of Natural Resources, one to backstop each of the two work commitments. The company said it plans to soon "explore its options with the DNR regarding the status of the first bond."

The original unit agreement listed Sept. 1, 2013 as the deadline for both commitments. The Alaska Department of Natural Resources placed the unit in default in late September and gave Buccaneer the current deadlines of Dec. 1 and Jan. 31 at that time.

If Buccaneer misses the January deadline, the unit could terminate and two of the leases could expire retroactive to the end of their primary term, according to the agreement.

Buccaneer had originally planned on drilling the well in August.

The West Eagle unit is located in the southern Kenai Peninsula, some 20 miles east of Homer. The West Eagle No. 1 well is targeting an upper Tyonek interval where Standard Oil Company of California encountered gas in 1961 with the Anchor River No. 1 well.

Cosmo permits

While Buccaneer prepares to spud West Eagle, it is awaiting permits to allow it to move forward on drilling the Cosmopolitan No. 2 well at the offshore field of the same name.

The Endeavour jack-up rig is docked in Port Graham, according to Buccaneer. The rig arrived at the port south of Homer earlier this year, after Buccaneer was forced to abandon a well at the offshore Southern Cross unit because of winter drilling restrictions.

The program is based on the premise that the offshore Cosmopolitan field is far south enough in Cook Inlet to accommodate winter drilling. Buccaneer said it applied for an Alaska Oil and Gas Conservation Commission permit for the well on Oct. 8, but "has yet to receive clear guidance from the agency with respect to its drilling plan and timing."

The Cosmopolitan No. 2 well would delineate the gas zones encountered in the Cosmopolitan No. 1 well earlier this year, according to Buccaneer. The field is generally thought to be oil prone, and Buccaneer said it might deepen the well at a later date.

Kenai Loop numbers

The Kenai Loop field likely contains 13.4 billion cubic feet of natural gas from two gas-bearing sands, according to new third party reserves Buccaneer has recently released.

The proved reserves include the sands at 9,700 feet and 10,000 feet at the onshore field north of Kenai, according to the engineering firm Ralph E. Davis Associates Inc.

The 13.4 bcf estimate also covers the probable reserves at the field. The report estimated that the field contains some 27.6 bcf of possible resources. Generally, "probable" means there is at least a 50 percent chance of recovered volumes meeting the estimate, and "possible" means at least a 10 percent chance of recovered volumes meeting the estimate.

The figures cover reserves net royalty interests, as required by Australian securities regulations. The company said described gross possible reserves closer to 19.3 bcf, based on recent mapping. Buccaneer believes it could drain those reserves using three wells.

The report also included a best estimate of 37.6 bcf for the prospective resources in the 9,700-foot sand. The estimate comes from a range of 18.8 bcf to 56.4 bcf. For the entire field, recent mapping indicated a best estimate of 53.4 bcf, which could be drained with eight wells, according to the company. The estimate includes other prospective sands.

The Kenai Loop field is at the center of a legal dispute between Buccaneer and the landowner Cook Inlet Region Inc. over leases and wells at the field. The AOGCC has scheduled a hearing in late January to hear complaints from CIRI on the matter.

The Kenai Loop field is currently producing some 8.8 million cubic feet per day from two wells and has produced some 4.7 bcf since coming online, according to Buccaneer.

Partnering, selling

All these activities come as Buccaneer is struggling to keep two offshore units.

The state is poised to terminate the Southern Cross and North West Cook Inlet units because Buccaneer failed to meet drilling deadlines earlier this year. Buccaneer is arguing that the missed deadlines were the result of logistical delays and believes its good faith efforts and spending in the region to date should justify a year of clemency.

Even with a reprieve from the state, though, Buccaneer will need a financial partner to proceed at the units. Buccaneer recently terminated a farm-in agreement with the California independent EOS Petro Inc. that was to have paid for two wells each at Southern Cross, West Eagle and the deep oil segments of the ConocoPhillips-operated North Cook Inlet unit, as well as an option for two wells at North West Cook Inlet.

Buccaneer said "multiple parties" have expressed interest in buying or farming-in unnamed assets in its portfolio, but the proposals are all "conditional and non-binding."

In a statement, Buccaneer Chief Executive Officer Curtis Burton said the company is mapping "tactical and strategic plans" going forward. "These plans include revisiting our capital position, our holdings and our near term development plans," Burton said. ●

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● PIPELINES & DOWNSTREAM

Northern Gateway faces new unknown

Enbridge gains regulatory endorsement along with 209 conditions; faces more entrained opposition from environmentalists, First Nations

By GARY PARK
For Petroleum News

To the surprise of few, but the outrage of many, Enbridge's Northern Gateway project, designed to be the first route to Asia for commercial quantities of oil sands crude, has cleared its first significant regulatory hurdle.

A Joint Review Panel of Canada's National Energy Board and the Canadian Environmental Assessment Agency delivered a recommendation to the Canadian government for a final decision by about mid-June that essentially endorsed the plans to export 525,000 barrels per day of crude bitumen to the Pacific Basin and import 193,000 bpd of condensate.

In line with a checklist it issued earlier this year, the JRP attached 209 conditions it said Enbridge must meet, primarily involving the prevention or cleanup of oil spills in coastal waters and on land and other action to protect the environment and wildlife.

The recommendations can either be accepted or rejected by the cabinet of Prime Minister Stephen Harper, but not modified.

A long ways to go

The building consensus is that the project is, to borrow a phrase from Winston Churchill in the Second World War, "not even at the beginning of the end, but is, perhaps, at the end of the beginning."

The JRP's bottom-line conclusion was clear: "The project, if built and operated in compliance with the conditions set out, would be in the public interest. Canadians would be better off with the project than without it."

But, in the midst of an exhaustive report, it delivered a telling rebuke suggesting Enbridge should have done more to openly communicate with First Nations — a sore point with aboriginal communities from the outset and now representing what could be the ultimate game-breaker.

The concept of diversifying Canada's oil export markets beyond the United States was first floated a decade ago by Enbridge.

It got stalled in mid-2007 when PetroChina quit as one of the potential shipping partners, lashing out at oil sands producers and the Canadian government for their failure to help it aggregate enough shipping volumes to underpin a possible 49 percent equity stake for the Chinese state-run giant.

Fresh start in 2009

The venture got a fresh start two years later, backed by 10 companies that have signed precedent agreements to buy volumes from Northern Gateway, by which time it was entangled in a double bind — the rapid emergence of shale oil across North America and the highly sophisticated, well-funded environmental organizations that identified the oil sands as the planet's "dirtiest" oil and vowed to do everything possible to stop oil sands expansion, using Keystone XL as their launching pad.

Undaunted, Enbridge plugged on, filing a regulatory application, entering a fractious public hearing phase that lasted 18 months and, with the financial backing of its partners, spending more than C$500 million to reach the current point.

The JRP said that the environmental, societal and economic burdens of a large spill, while unlikely and not permanent, would be significant, but credited Enbridge's efforts to mitigate any accidents through its "precautionary design approach" and plans to use "innovative safety systems."

"The likelihood of significant adverse environmental effects resulting from project malfunctions or accidents is very low," the JRP said.

Beginning of the fight

The environmental organizations brushed off those calming observations, declaring that the JRP report is merely the beginning of their fight to scuttle Northern Gateway.

Many First Nations along the pipeline route from Alberta to a deepwater port at Kitimat on the northern British Columbia coast issued the same threats.

Grand Chief Stewart Phillip, of the Union of British Columbia Indian Chiefs, said he was "deeply disappointed" by the JRP's conclusion that during construction and routine operations Northern Gateway would not have a significant impact on the ability of aboriginal people to use their land, water and resources.

He said the JRP's failure to deal with aboriginal concerns over the prospect of a "catastrophic oil spill or a serious pipeline rupture on our coast or in the mountains" had set the stage for a legal battle that could grow into civil disobedience.

"The indigenous people (of British Columbia) have made our position very clear," Phillip said. "We now look forward to a long, protracted battle — legally, politically and, if necessary, on the land."

Ellis Ross, chief councillor of the Haisla First Nation in northwestern British Columbia and a backer of plans to export LNG, said aboriginal opposition to Northern Gateway has only hardened.

"Our concern was the remediation in response to an oil spill and I don't think that got covered off at all," he said.

Other First Nations leaders provided variations on the same theme, all pointing to an early start on the legal front, echoing an announcement by a coalition of environmental groups that a war will now be waged against the Canadian government as it weighs the project's fate.

"I'm convinced now — and I think a lot of people share this feeling — that our government and its processes no longer belong to the people," said Gerald Amos, chairman of the Friends of Wild Salmon Coalition of northwestern British Columbia. "They belong to the big oil companies."

The call for wider consultations

Enbridge Chief Executive Officer Al Monaco was quick to latch on to the JRP's call for wider consultations with First Nations.

"As a company, we want to do the right thing. We want to engage and we want to understand their concerns. We would like an opportunity to have that discussion," he said.

Monaco said Enbridge is "not celebrating" the JRP's findings, adding he viewed the conditions as "expectedly tough" without containing any "real major surprises."

He said the Northern Gateway objective has not just been to obtain regulatory approval. It is committed to "making sure that people understand the project well ... (and have) comfort around the technical and safety aspects."

Canada's Natural Resources Minister Joe Oliver said the JRP report was a "rigorous, open and comprehensive science-based assessment. We will thoroughly review it, consult with affected aboriginal groups and then make our decision."

Formal discussions planned

Less than two weeks before the JRP report became public, officials in the Harper government notified aboriginal leaders who participated in the JRP hearings that formal discussions aimed at meeting the government's duty to consult and accommodate their concerns would begin early in 2014.

But the letter cautioned that the scope of consultations would be confined to the pipeline project itself and not get sidetracked into negotiating treaties with First Nations. Many observers believe aboriginal communities will use Northern Gateway as leverage to assert their land claims.

A school of thought is also taking shape that Northern Gateway will fail, leaving Kinder Morgan's plans to triple capacity on its Trans Mountain system to 890,000 bpd as the only survivor of the industry, partly because it operates on a long-established right of way to Vancouver, and Harper's strongly held view that opening markets in Asia is vital to development of the oil sands and to generate the revenues needed to support domestic programs such as health-care and education.

Industry argument

Almost lost in the clamour surrounding the JRP report is the industry's argument in support of pipelines and market access.

Greg Stringham, the Canadian Association of Petroleum Producers vice president of oil sands and markets, said the JRP report is an "important milestone in the process to achieve market diversification for Canada's valuable oil products."

He said CAPP estimates that over the next 15 to 20 years Canada will need to "find a home" for another 2.5 million to 3 million bpd of output.

Stringham left no doubt that such volumes will require either approval of a substantial list of pipeline projects, or some other alternatives. .

The pipelines include Northern Gateway and the Trans Mountain Expansion, Keystone XL's proposed 830,000 bpd, TransCanada's Energy East project to ship 1.1 million bpd to Ontario, Quebec and New Brunswick and possibly open routes to Europe and Asia and Enbridge's Line 9 reversal to deliver 300,000 bpd to Ontario and Quebec.

All of those proposals hang in the balance, pending the outcome of Northern Gateway.

Stringham touched on the challenges by suggesting the JRP has "opened the door ... but that's all it has done" for Northern Gateway, while doubting that all of the concerns raised by opponents could be resolved.

Like Monaco, Stringham was reluctant to speculate on what might happen if Northern Gateway dies because of drawn-out legal battles. But that seems to be the project's destiny. ●

Contact Gary Park through publisher@petroleumnews.com

● ALTERNATIVE ENERGY

Renewable energy: a level playing field?

Aspiring Alaska independent power producer requests changes in rules that can determine viability; utilities argue for status quo

By ALAN BAILEY
Petroleum News

The relationships between Alaska Railbelt electric utilities and businesses wishing to independently supply power to the Railbelt grid, in particular from wind farms, have not been especially happy in recent years, with the would-be new producers arguing for the benefits of new renewable energy sources and the utilities tending to baulk at what they claim to be the high cost of independent power. Currently the utilities operate the bulk of the power generation facilities on the Railbelt electric transmission grid.

In the latest twist in the debate over the addition of independent power producers, or IPPs, to the Railbelt power supply arrangements, Alaska Environmental Power LLC, or AEP, has petitioned the Regulatory Commission of Alaska to change the rules for small-scale power generation on the grid. AEP wants to build a wind farm at Delta Junction in the Alaska Interior but has been unable to agree with Golden Valley Electric Association, the local electric utility, on terms under which this wind farm would supply power.

Golden Valley Electric has already implemented its own wind power facility at Eva Creek near the town of Healy.

The petition focuses on four issues: the way in which a utility determines the cost of the power that an IPP displaces when connected to the grid; the way in which the cost of integrating an independent power source into the grid is calculated; the circumstances under which a utility can curtail power production from a specific facility; and the bidding process used for the evaluation and approval of proposed renewable energy projects.

Avoided cost

The cost of displaced power, referred to as the avoided cost, is a critical factor in determining the economic viability of a new power plant. If the cost of power from the new plant will be more than the avoided cost, construction of the plant does not make economic sense.

Under current Alaska regulations the utilities use their average cost of power as the avoided cost. The IPPs, however, want the regulations to require the utilities to determine the avoided cost by initially using their highest cost of power and incrementally adding successfully lower costs from other power sources, depending on how much power is displaced. This incremental approach to the avoided cost calculation results in a cost figure that would be higher than the average cost and hence more favorable to the economics of adding new independent power to the grid, the IPPs say.

The rationale behind using the incremental cost rather than the average cost calculation is an expectation that when an IPP brings new power generation on line a utility will switch out its most expensive generation first, to minimize its cost of power.

The average cost method used in Alaska places a new facility at an economic disadvantage and is inconsistent with the incremental cost method mandated by the federal Public Utilities Regulatory Policy Act, said the Alaska Independent Power Producers Association, or AIPPA, in a filing in the RCA case.

Reasonable approximation?

But the simple 12-month average cost calculation used in Alaska does reasonably approximate the incremental cost required under federal law, Chugach Electric Association, a major Southcentral Alaska electric utility, told RCA. And, while current regulations assume average cost as the default means of calculating the avoided cost, the regulations allow the commission to approve other calculation methods, the Chugach Electric filing said. There are no doubt many potentially legal ways of calculating avoided costs when negotiating power sales and agreements, the utility said.

Chugach Electric currently purchases a small amount of independent power from a new wind farm on Fire Island, offshore Anchorage, owned and operated by Cook Inlet Region Inc.

In its RCA filing Anchorage electric utility Municipal Light & Power commented that the average cost calculation became the default standard in Alaska some years ago because of the difficulty of calculating the avoided cost by any other means, either on a moment-to-moment basis or on an average basis. The introduction of power from an independent source can have a variety of impacts on the existing power generation facilities, including the continued running of a machine, the shutting down of a machine, or not starting one machine while perhaps starting another. And power generation decisions are sometimes impacted by the cost consequences of using hydropower in one hour rather than another, ML&P said.

"Avoided cost is not easily determined or agreed upon by adverse parties, is not necessarily, or even usually, higher than average cost, and can often be close to zero," ML&P said.

Integration costs

The cost of integrating new power generation into an electricity grid can be particularly tricky for a continuously varying power source such as a wind farm, where the power output depends on the vagaries of how strongly the wind blows from one moment to the next. The grid operator needs to have available some other power source, the output of which can be continuously varied to fill in the troughs in the wind farm power. Operating this compensating power source and having it available costs money, thus adding cost to the wind power output. Grid integration costs became a major bone of contention in negotiations between Cook Inlet Region Inc. and Alaska utilities over the purchase of power from the Fire Island wind farm.

Given the current absence of any Alaska regulations governing the determination of integration costs, RCA should implement new regulations setting a presumption that integration costs are zero unless a utility can demonstrate otherwise, AIPPA said in its filing. This would have the effect of placing the onus on a utility to prove legitimate and verifiable integration costs, directly linked to the proposed new facility. And RCA should require consistent integration fees for similar IPP projects, with the fees being transparent, verifiable, just and reasonable, AIPPA said.

Chugach Electric commented on the likely difficulty of developing any regulations governing integration costs, given the unique circumstances surrounding most new power generation proposals and the large number of variables that can come into play in determining the cost of integration. And trying to impose a general regulation for use in a range of situations, each unique and complex, runs the risk of unintended consequences, not anticipated by the regulators, Chugach Electric said.

Curtailment

Issues surrounding the curtailment of a power source relate to a question of whether a utility would use its curtailment practices to circumvent mandated small-scale renewable energy purchase obligations — the operator of a power grid will typically adjust its use of different power sources to accommodate the continuous variation of the power load on the grid, preferentially curtailing its use of its more expensive power sources if the load drops.

AIPPA said RCA does have current regulations governing curtailment and that, while there is no reason to modify these regulations, the commission might consider adding a provision expressly stating that the regulations are not intended to alter a utility's obligation to purchase power from a facility.

ML&P said it understands that RCA follows curtailment rules set by the Federal Energy Regulatory Commission and that these regulations limit curtailment appropriately. Chugach Electric said it would wait to see any proposals relating to curtailment before commenting.

Competitive bidding

AIPPA said competitive bidding for the provision of renewable energy for the grid was already stunted by other impediments to renewable energy, such as the methodology for calculating avoided costs. However, it may be worth exploring ways of mediating disputes or achieving dispute resolution during negotiations over proposals for independent power production, the organization suggested.

Chugach Electric commented it is unlikely that RCA has the authority to create an independent body to oversee bids from IPPs, as a substitute for the judgment of the boards and managements of regulated utilities. A fundamental issue such as this would likely need to be mandated by statute, the utility said. Open bidding, a process normally reserved for government contracts, increases the costs of transactions and would likely increase the cost of renewable energy, ML&P said. Moreover, since utilities have to purchase power from small renewable energy facilities at a price equal to the avoided cost, it is not clear how any sales from these facilities could be bid, ML&P commented. ●

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● EXPLORATION & PRODUCTION

EIA sees sharp rise in gas exports

Increasing production and lower prices are expected to drive LNG exports to 3.5 tcf by 2030 with help from Alaska project

By ERIC LIDJI
For Petroleum News

The federal government expects natural gas exports to rise in the coming decades.

Liquefied natural gas exports could reach 3.5 trillion cubic feet by 2030 with the help of an Alaska natural gas project, according to the U.S. Energy Information Administration.

The estimate comes from the reference case of the Annual Energy Outlook 2014, which the statistical arm of the Department of Energy has released in an abridged form.

The full report is due out next spring.

The reference case expects LNG exports to increase through 2025 when an Alaska project would come online, plateau at 3.5 tcf in 2030 when an Alaska project peaks, and maintain at that level through 2040, the end of the period considered in the report.

The report also expects natural exports by pipeline to increase.

The report expects domestic production to grow significantly.

The EIA expects exports to Mexico to grow 6 percent each year from 0.6 tcf in 2012 to 3.1 tcf in 2040 and exports to Canada to grow 1.2 percent each year from 1 tcf in 2012 to 1.4 tcf in 2040. Canadian imports are expected to fall 30 percent during that time.

The reference case forecasts energy trends under current laws and regulations.

The full report will include alternative cases showing how exports might change under various price and economic environments, and compared to various alternative fuels.

Gas and oil split

The report expects domestic production to grow significantly.

The EIA sees oil production growing 800,000 barrels per day through 2016 to a total of 9.5 million bpd, which would approach the historic highs from the 1970s.

The forecast expects domestic oil production to slowly decline after 2020, but expects natural gas production to grow 56 percent between 2012 and 2040 to 37.6 tcf.

The growth in gas production and associated low prices are expected to increase industrial shipments by 3 percent over 10 years and 1.6 percent through 2040. The shipments are expected to be largely bulk chemicals and metals-based durables.

The EIA expects gas to overtake coal as the primary power generation fuel in the country by 2040, with 35 percent of electricity coming from gas and 32 percent from coal. ●

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● PIPELINES & DOWNSTREAM

Kinder Morgan enters regulatory realm

Formally submits application to triple capacity on Trans Mountain system to 890,000 bpd, open route for oil sands crude to Asia

By GARY PARK
For Petroleum News

Kinder Morgan has set in motion the regulatory process for plans to almost triple capacity on its Trans Mountain pipeline system, with its sights fixed primarily on delivering oil sands bitumen to Asia and confident that it can satisfy the British Columbia government's conditions for support.

The company has filed more than 15,000 pages of application documents with Canada's National Energy Board, seeking approval for a C$5.4 billion plan to boost capacity on Trans Mountain to 890,000 barrels per day from 300,000 bpd.

The proposal includes two lines, one with sustainable capacity of 350,000 bpd and the other with 540,000 bpd and will involve the construction of almost 600 miles of new 36-inch main pipeline.

For about 73 percent of the total route, the new pipeline segments will be directly contiguous with the existing Trans Mountain easement.

An expanded Westridge terminal in Port Metro Vancouver will be designed to handle up to 630,000 bpd and 34 Aframax class vessels per month with capacity of about 650,000 barrels each.

Ian Anderson, Kinder Morgan's Canadian president, told a conference call his company is confident the application and regulatory process "will fully address the needs and the interests of British Columbia and the residents."

He said the filing includes the "views, concerns and observations" Kinder Morgan gathered during meetings with First Nations, affected citizens, the public and other stakeholders including governments in British Columbia and across Canada.

BC set five conditions

British Columbia Environment Minister Mary Polak would not tell reporters whether she believed Kinder Morgan has met the five conditions — primarily involving procedures to handle spills on water or land, full consultation with First Nations and direct economic benefits for British Columbia — which her government also attached to Enbridge's Northern Gateway project.

If approved, the Trans Mountain expansion, covering a route of almost 700 miles from Edmonton, Alberta, is expected to be in operation by late 2017.

"We're not going to prejudge the process," she said. "We'll be reviewing the application and (will determine) if there is any additional information that we require in preparation for the hearings that are anticipated."

Polak said the province is likely to apply for intervener status as it did with the Northern Gateway hearings.

The five conditions include a world-class marine spill response, full engagement of First Nations and a "fair share" of the project economic benefits for British Columbia.

Those terms were part of a contentious process that resulted in a framework agreement between Alberta and British Columbia that was announced in November, but has not yet been translated into a formal document.

NEB will set hearing schedule

The NEB is now expected to develop a hearing schedule in line with new Canadian government legislation that sets a 15-month deadline on a review and decision, which requires final ratification by the federal cabinet.

If approved, the Trans Mountain expansion, covering a route of almost 700 miles from Edmonton, Alberta, is expected to be in operation by late 2017.

In the meantime, Kinder Morgan said it will continue reaching out to the public with forums and workshops to review the application and collect input and advice on the issues that are "top of mind" for parties affected by the project, Anderson said.

The ongoing engagement process with First Nations will include detailed discussions about how those communities will be affected and how the impacts can be mitigated, he said.

Anderson said that over the past 18 months Kinder Morgan, which has established a strong relationship with First Nations during earlier Trans Mountain expansions, has learned the "critical importance" of the major role First Nations must play in the project planning.

The company has had discussions with more than 100 aboriginal communities and executed 46 different agreements including memorandums of understanding and capacity funding agreements.

Anderson said none of the deals are "explicit letters of support for the project ... but we are working towards that end with virtually all of them."

Vancouver opposition

In the Greater Vancouver area opposition has been strong from environmental groups and municipal councils, notably Vancouver Mayor Gregor Robertson, where there is opposition to increased crude tanker traffic through a heavily populated area.

Anderson said Trans Mountain has safely loaded vessels for almost 60 years and is "very confident in the existing regime and existing safety standards that are in place."

Regardless of that, he said "we support the studies by the Canadian and British Columbia governments and support the recommendations that are being made to add resources and response capability to those regimes as tanker traffic is forecast to increase."

In its application, Kinder Morgan has recommended further improvements to marine safety and spill response, including extending tug escorts for loaded tankers through the Strait of Georgia and Juan de Fuca Strait.

Greg Stringham, vice president of oil sands and markets with the Canadian Association of Petroleum Producers, said the prospect of Trans Mountain bolstering market access beyond North America for Canadian energy is "critical to create jobs and provide economic benefits for all Canadians."

Brenda Kenny, president of the Canadian Energy Pipeline Association, said the application is an "important milestone for the company and the industry," but cautioned that many regulatory requirements must be resolved before a final decision can be made. ●

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● FINANCE & ECONOMY

Miller Energy answers its critics

In response to challenge from dissident shareholders, company defends its record, says it is 'open to constructive engagement'

By WESLEY LOY

For Petroleum News

Miller Energy Resources Inc. says it is taking criticism from a group of dissident shareholders "very seriously."

The group, which calls itself Concerned Miller Shareholders, recently sent a blistering open letter to fellow shareholders urging replacement of company board members and senior management.

"We believe the company has great assets and a strong operational team in Alaska, but Miller shares are dramatically undervalued due largely to the incompetence of Miller's senior management and lack of relevant experience, together with its excessive compensation and unacceptable self-dealing," the letter said.

On Dec. 19, Miller Energy released a statement on the letter.

"The board values the opinions of all of our shareholders, and is always open to constructive engagement with them," the statement said. "Therefore, despite the fact that the dissidents appear to be led by a former consultant whose contract was not renewed by the company, we are carefully evaluating the concerns raised in their letter."

Alaska managers 'excluded'

The dissidents have a website at http://millproxy.com. The full text of the letter is posted there.

The dissidents are nominating a slate of "independent, extremely qualified" board candidates for election

see MILLER ANSWERS page 12

● FINANCE & ECONOMY

AIDEA to assess value of Agrium plant

By WESLEY LOY

For Petroleum News

A state lending agency plans to assess the market value of the shuttered Agrium Inc. fertilizer factory at Nikiski on Alaska's Kenai Peninsula.

In a request for proposals, or RFP, issued Dec. 20, the Alaska Industrial Development and Export Authority said it aims to award a contract to an appraiser by early February.

The Agrium plant was long a major user of Cook Inlet natural gas as a feedstock to produce nitrogen fertilizer products. The company shut down the plant in September 2007 for lack of sufficient affordable gas.

Since then, some progress has been made to prove up additional supplies of inlet gas. Economic development boosters would like to see the Agrium plant come back to life as a source of good jobs and to serve as an industrial customer for gas producers.

The shutdown resulted in the layoff of more than 100 employees.

James Hemsath, an AIDEA deputy director, told Petroleum News there's some chance the plant might be upgraded and restarted.

AIDEA could be asked to loan money to the venture, and an appraisal of the plant is needed for collateral purposes, he said.

Agrium, based in Calgary, is a global supplier of agricultural products.

With the recent rise in drilling for natural gas in Cook Inlet, Agrium is assessing the potential for restarting at least one of the two production trains at the Nikiski plant, the RFP said.

The plant was one of the largest of its kind in North America, and used very large volumes of gas.

Unocal built and operated the plant from 1968 to 2000, when it sold the facility to Agrium.

The plant produced ammonia and urea

see **PLANT ASSESSMENT** *page 11*

EXPLORATION & PRODUCTION

State conditionally opens tundra travel

The Alaska Department of Natural Resources has opened the eastern and western coastal areas of North Slope state land for winter tundra travel. But special conditions including the use of summer-approved vehicles may be imposed at two locations, one in each area, where the deep and dense snow pack has insulated the soil, keeping soil temperatures close to 0 C, well above the minus 5 C at a depth of 30 centimeters required for off-road travel using regular vehicles. Two other locations had temperatures slightly above the required level but were expected to cool sufficiently by the time that the tundra opening announcement was made, the department said.

Snow depths are high, averaging more than 11 inches, throughout the coastal areas, with a high snow density and with a snow structure optimal for off-road travel, the department said.

However, anyone wishing to conduct off-road travel in the areas that have been opened has to obtain an off-road travel permit from the department.

Tundra travel remains closed in the lower and upper foothills areas of state land. Although the snow cover remains thin at three monitoring stations, the foothill areas generally have achieved the required snow depth of nine inches. But soil temperatures in these areas are quite variable, depending on the snow depth, although they are beginning to drop below 0 C in the lower foothills, the department said.

—ALAN BAILEY

ENVIRONMENT & SAFETY

EPA issues carbon sequestration rule

Following its September issue of a proposed rule to limit the carbon emissions from new power stations in the United States, the Environmental Protection Agency, or EPA, has issued a final rule clarifying that carbon dioxide captured from emissions sources and sequestered underground under specific conditions will be excluded from the agency's hazardous waste regulations.

Under EPA's proposed rule for power stations, new coal-fired power stations would require the use of carbon capture and sequestration, or CCS, technologies to ensure that their carbon emissions remain below regulated limits.

"Carbon capture and sequestration technology can help us reduce carbon pollution and move towards a cleaner, more stable environment," said Mathy Stanislaus, EPA assistant administrator for solid waste and emergency response, when announcing the new rule on Dec. 19. "Today's rule provides regulatory clarity to help facilitate the implementation of this technology in a safe and responsible way."

EPA says that it has concluded that the careful management of carbon dioxide streams, injected underground using a specific type of well, does not present a substantial risk to human health or the environment. The rule also clarifies that the underground injection of carbon dioxide for the purpose of enhanced oil recovery in an oil field is not expected to be a waste management activity.

The agency is also releasing for public comment draft guidance for converting wells of a certain type into wells suitable for carbon sequestration.

A number of people have expressed skepticism over the use of CCS technology, saying that the technology has not reached the level of maturity required for commercial operation and that the cost of using the technology in conjunction with power generation would be uneconomic.

—ALAN BAILEY

ENVIRONMENT & SAFETY

New funding for Climate Science Center

Interior Secretary Sally Jewell has announced new research funding for Interior's chain of regional climate change science centers, including the Alaska Climate Science Center, hosted by the University of Alaska.

Funding of more than $130,000, shared with the Northwest Climate Science Center and North Pacific Landscape Cooperative, will focus on helping Native groups plan for and adapt to climate change, Interior says.

"Even as we take new steps to cut carbon pollution, we must also prepare for the impacts of a changing climate that are already being felt across the country," said Jewell when announcing the funding. "These new studies, and others that are ongoing, will help provide valuable, unbiased science that land managers and others need, to identify tools and strategies to foster resilience in resources across landscapes in the face of climate change."

Funded projects focused on Alaska include research into the decimation of subsistence berry harvests in Southcentral Alaska by a species of moth, in unprecedented moth outbreaks believed to be related to climate change. Another project will identify the climate vulnerabilities of eulachon, a highly nutritious form of smelt that people of the Tlingit Nation in Southeast Alaska depend on as a food source and as part of their culture.

The Alaska center will also continue five funded projects from earlier years, including climate research ranging from ecosystem modeling to understanding the impacts of coastal storms, Interior says.

—ALAN BAILEY

ALTERNATIVE ENERGY

Electrical intertie standards go to RCA

The Intertie Management Committee that oversees the operation of the 170-mile state-owned electrical transmission intertie between Willow and Healy has submitted new operation reliability standards for the intertie to the Regulatory Commission of Alaska for review. The intertie provides the only power transmission linkage between Southcentral Alaska and the sections of the Railbelt transmission grid that serve the Fairbanks area of the Alaska Interior.

The Railbelt grid is undergoing a period of transition as new power generation is added to various points of the grid, bringing additional utilities into the business of managing the dispatch of power around the grid.

With multiple utilities using the Railbelt grid for the shipment of power and for balancing power supplies from multiple generation systems with demand from multiple population centers, a clear set of standards that all users must comply with is critically important to smooth intertie operation. The Railbelt grid is undergoing a period of transition as new power generation is added to various points of the grid, bringing additional utilities into the business of managing the dispatch of power around the grid.

Appropriate standards can also ensure equal rights of access to the grid for all potential grid users.

The Intertie Management Committee consists of the leadership of the Alaska Energy Authority, Chugach Electric Association, Golden Valley Electric Association, Matanuska Electric Association and Municipal Light & Power.

"We want to provide reliability and a standard for interconnected grid operations, while incorporating non-discriminatory open access," said Brad Evans, Chugach Electric CEO and chairman of the committee, when announcing adoption of the new standards.

"The managers and operators of the intertie, including the Alaska Energy Authority, have been actively working on the development of expanded open access language for two years, as part of the Alaska Intertie Agreement," said Sara Fisher-Goad, AEA executive director. "The committee's actions honor the open access principles that are important to the state while advancing reliability standards to the RCA."

—ALAN BAILEY

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OLSON Q&A

What she submitted and what we passed were two different animals.

Petroleum News: I've heard more than one critic of the referendum say a repeal could hurt investment. Do you have any other concerns about the referendum?

Olson: If the people want it, that's what we have to live with. I've been unhappy in the past, I've been happy, depending on which time it was. Like the cruise ship tax. It started out to be good when there were one or two issues until it got Christmas treed. There were too many things piled into it later on. I had a problem with that one, but it was the people speaking. I don't believe that's the best way to do government, by initiative. Whether or not it's going to pass, I haven't seen any recent polls. I imagine it's relatively close. I'm sure we'll see a lot of money pouring in for advertising before the vote from both sides.

Petroleum News: Now that some of the populist movement during the Palin administration and the corruption cloud are pretty much a thing of the past, do you notice a different in tone?

Olson: I don't want this to sound negative. We have a number of new people who didn't have the luxury of being around PPT, ACES and AGIA. Some of them are starting from scratch. A lot of them are quick studies. Going back to PPT, we had a roundtable discussion with all of the producers, with the exception of Exxon. Then we had several explorer companies beginning to be active on the North Slope in an open forum with questions and answers going back and forth. One of the questions was how far out does your company forecast the development of future projects. Only one company answered it. The rest said it's proprietary. The one company said it looks out a minimum of 60 years. We can't even get a budget out for two years, let alone do that kind of forecasting. That attracted my attention. I figured some place in London there is a map on the wall with different colored pins corresponding to an area, what decade they will be developing or what country.

Ultimately, the advantage we have is that we may not have fiscal stability but we have a stable political regime. We are not a third-world country. We don't have hostile neighbors. We don't have to invest a lot of money securing our assets. And we don't have to worry about political coups. From that standpoint, we have something to offer for a premium because we have that kind of political stability. On the flip side, what do we have — a construction season of about four or five months? We are remote. Our transportation infrastructure is probably adequate but certainly not world class. On the North Slope, when we have the ability to use the water transportation, we don't have the ports up there to handle it, we don't have icebreakers. I believe the Chinese have ordered six new icebreakers and they aren't even an Arctic nation. They are getting ready to be one. I believe there are a lot of things we can do to make ourselves more attractive to development and to command maybe a higher tax structure, but at this point and time, I think SB 21 hits pretty close to what will work.

Petroleum News: You've noted the Arctic. Have you been able to keep an eye on what's happening there, either by watching the Arctic Policy Commission and if so what were your impressions?

Olson: No 1, I think we are going to have to spend money on the North Slope for infrastructure and that would be at least one deepwater port. We are going to have to have ice breakers that would be either state or federal at some point. We are going to have to have tugs on the North Slope. We've already had one load of LNG go over the top. LNG is not going to cause a problem if we have a stranding or some kind of catastrophe. But it we that same thing with oil, we'd have another Exxon Valdez with no cleanup. So we'll have to have some infrastructure up on the North Slope if we are going to utilize the ability to transit in either direction up there, if we are going to bring in supplies or if we are going to haul out oil possibly. So I think that's my greatest concern: that we may start doing things up on the North Slope before we have the cleanup infrastructure or the ability to contain or clean up a spill, or help the vessels that might be in distress.

Petroleum News: Still on the Arctic. Are you hopeful that Shell will be back exploring in the summer?

Olson: It's my understanding at this point they are. I guess we will know after the first of the year. I think the people to ask would be Shell. They have put an incredible amount of money in it without anything coming to fruition. They've made some mistakes and it's surprised people because it was Shell.

Petroleum News: Let's look closer to home: Cook Inlet. There has been a lot of good news during the interim, either with supply news and most recently ConocoPhillips applying for the export permit. Did you ever think Cook Inlet would have this kind of revival?

Olson: You know I really had hoped it would work when we had the Stampede. Originally, I thought we might be giving too much away. I think the credit goes to (former) Sen. Wagoner. Tom led the charge on that. I, for the most part, was there and was definitely encouraged that we were actually doing something at that point. I wondered if we were giving away too much or had not structured it right. It seems to be working as it was intended. I can tell you that there is a lot of activity going on down here. We've also had Agrium up here all summer. I think as soon as they have an extended supply of gas, we might see them reopen. I moved down there in 1982 when we were still putting new platforms in the inlet. This is the most activity I've seen since probably the late '80s.

Petroleum News: You certainly can't compare Cook Inlet to the North Slope, but do you think it's a blueprint for how policy can drive economic change?

Olson: I don't think you can, but the policy is working or you wouldn't be seeing the activity you are seeing today. For a long time, Nikiski was known as the rust belt. I remember companies I worked with in one form or another over the years. I can go out there and name every one of the empty buildings and what they had during their height. Now we are drilling all over downtown Kenai, and they hit gas right behind Wal-Mart. It's just a mile and a quarter from where they could tie it into the distribution system. Where we have a real future is we've got new companies coming in. We've got people like Buccaneer; we've got Hilcorp that is basically made up of a number of Marathon people who are real active. We are going through a transition. As far as I can tell it's proving better. It's coming back. ●

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POWER OF EOR

will typically recover around 10% of the available volume in place," the article says. "Unless other forces act on the oil, pressure in the reservoir will naturally fall as it empties, until, eventually, there isn't enough to force up oil."

Producers long ago discovered they could maintain reservoir pressure by injecting water or gas underground. Water injection, or waterflooding, is almost as old as the industry itself, and very important for BP's production, the article says.

"Injecting gas to maintain reservoir pressure is not as common as water injection, both because gas is a valuable — and marketable — commodity in its own right, and because more sophisticated machinery is needed to inject it. But it, too, is a technique that BP has used at large scale since the 1980s."

EOR generally refers to techniques that go beyond the simple injection of water or gas to maintain pressure, the article says.

One of the most widely used EOR methods is using steam to heat up viscous oil, making it easier to recover.

Mixing in gas

BP operates Prudhoe Bay on behalf of itself and other owners including ConocoPhillips and ExxonMobil. The field has produced since 1977, yielding about 12.4 billion barrels of crude thus far.

BP processes natural gas at Prudhoe for EOR purposes.

The article quotes Bharat Jhaveri, BP senior adviser for gas EOR:

"We take the enormous quantities of gas produced from the field, almost as much gas as Britain uses every day, and put it through an enormous refrigeration plant — effectively a $1 billion fridge — which takes it to -40°C (-40°F). This enables us to isolate components in the gas, such as propane and butane. Then, we create one stream of 'lean' gas that's virtually all methane, and another stream of what's called miscible gas — because it mixes with the oil, unlike water — which includes propane, butane and carbon dioxide."

The miscible gas is injected into wells in the oil zone to boost crude recovery.

Jhaveri continues: "Initially, the gas and the oil are in two different states — or — but, then, some of the heavier components in the oil transfer into the gas, and some of the intermediate components in the gas transfer into the oil until, at the interface, oil and gas begin to look like each other. You can't tell where the boundary is anymore; they're the same thing — and that makes it possible to push much more oil out of the rock with the injected gas."

The gas often is alternated with injections of water to improve the sweep through the rock, the article says.

BP says its hydrocarbon miscible gas project in Alaska is the world's largest.

'Relic oil'

The lean gas at Prudhoe Bay is used in another way.

Jhaveri explains that the whole Prudhoe structure originally was full of oil, but the field tipped and a gas cap formed atop the reservoir in space that previously held oil. As the gas moved in, the oil drained down over the sand grains and some of it got stuck.

"You end up with what's called 'relic oil' coating sand grains in the gas cap," Jhaveri says. "Only 8% of the oil sticks like this, so who cares? Well, we do actually, because there are 1 billion barrels of it at Prudhoe Bay."

The relic oil is patchy, lacking continuity, and can't flow. And pumping water through the well won't dislodge it.

"But, when you inject methane gas, components in the oil transfer to the gas," Jhaveri says. "It's analogous to having moisture on a surface and blowing warm air over it — the moisture vaporizes. Then, we put the gas through the processing facilities, followed by the fridge again, which separates the vaporized oil, before recycling the gas to pick up some more oil. We've been doing this since 1987 and, eventually, it will help us to recover several hundred million barrels of extra oil."

Gas injection is great for Prudhoe Bay, but not so desirable at fields where gas would have to be imported, the magazine article says.

BP has used other advanced EOR techniques in Alaska, including LoSal, which is a registered trademark of BP. LoSal involves low-salinity water, which can be better than seawater for displacing oil. Another technique called BrightWater, a Nalco trademark, uses expanding microparticles to improve sweep. ●

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LNG EXPORTS

making its "surplus determination in the context of a dynamic natural gas market."

"The board considers price as one indicator of market conditions as North American natural gas supply and demand adjust to changes in price signals."

Resource described as 'robust'

The NEB also factored in supporting submissions by Ziff Energy Group (a division of HSB Solomon Associates) and Roland Priddle, a former NEB chairman who is now an international energy consultant.

Ziff said North American and Western Canadian gas resource bases are "robust and continue to grow with the development of horizontal drilling and multi-stage fracture technologies and that supply is not constrained to meet projected base demand and incremental demand" from the projects over the forecast period.

The NEB said Ziff expects the North American gas markets to continue functioning in a "rational manner during the forecast period."

Priddle described the North American market as "highly liquid, open and efficient, and that Canadian gas markets have been adequately supplied ..." the NEB said.

The NEB argued that since deregulation of Canadian gas markets in 1985, North American markets have functioned efficiently, with no evidence that they will fail to do so in the future.

NEB satisfied with quantity

The regulator said it was satisfied that the quantity of gas proposed for export did not "exceed the surplus remaining after due allowance has been made for the reasonably foreseeable requirements for use in Canada, having regard to the trends in the discovery of gas in Canada."

Bill Gwozd, senior vice president at Ziff Energy Group (a division of HSB Solomon Associates), said the "very quick turnaround (in the NEB decision) represents a huge Santa Claus present for the four operators" giving them a chance to show to prospective LNG buyers that they are serious."

Ed Kallio, Ziff's director of gas consulting, said his firm's submissions in support of the four applications used the same template as accompanied the Shell application for an LNG Canada export permit.

He suggested that if the evidence did not support the applications the NEB would have been "asking questions."

Chris Theal, CEO of Kootenay Capital Management, said the NEB "fully recognizes the challenges facing the Canadian gas market."

The fact that the U.S. Northeast has moved from dependence on Canadian gas to a self-sufficient market "underscores the need for new markets for Canadian energy."

Methods to be scrutinized

Natural Resources Minister Joe Oliver said in a statement Dec. 17 that his department will scrutinize the methods used by the NEB to determine whether the LNG gas requirements are surplus to Canada's forecast supplies over the license periods which cover 25 years for each of the four latest approvals. But he did not elaborate on how the review process would be conducted.

Geoff Morrison, British Columbia manager for the Canadian Association of Petroleum Producers, said the NEB would only have granted the approvals if it deemed there were ample gas resources to serve domestic and international markets.

He said that position was reinforced with the release a month ago by the NEB and the governments of British Columbia and Alberta of "staggering" new resource estimates for the Montney formation in the two provinces. That report put the resources at 3,000 trillion cubic feet of gas, of which 449 tcf is thought to be economically marketable.

The latest permits approved by the NEB cover WCC LNG operated by ExxonMobil for up to 30 million metric tons per year or a gas equivalent of 4 bcf per day; Prince Rupert LNG operated by the UK's BG Group for 21.6 million metric tons per year or 2.91 bcf per day; Pacific NorthWest LNG operated by Malaysia's Petronas for 19.68 million metric tons per year or 2.74 bcf per day of gas; and Woodfibre LNG Export for 2.1 million metric tons per year or 290 million cubic feet per day of gas.

Other licenses awarded

Over the past two years, the NEB has awarded licenses to Shell-operated LNG Canada for 24 million metric tons per year requiring gas supplies of 3.23 bcf per day; Chevron-operated Kitimat LNG for a first train of 10 million metric tons per year or 1.28 bcf day; and BC LNG Cooperative for two trains of 1.8 million metric tons per year each and combined gas needs of 230 million cubic feet per day of gas.

Also before the NEB is an application by Aurora LNG, operated by China's CNOOC, which is seeking permission to export 24 million metric tons per year.

None of the projects has received a final investment decision, with most waiting for the British Columbia government to release its fiscal regime in the next provincial budget, expected in February, while they negotiate offtake orders.

The seven permit approvals and Aurora are all counting on obtaining their gas supplies from British Columbia's extensive shale and tight gas basins — notably Montney, Horn River, Fort Liard and Cordova — and northwestern Alberta's Duvernay play.

Cabinet must ratify

NEB permit approvals require final ratification by the federal cabinet before permits can be issued. That has occurred for the initial three permits.

The combined gas needs of 14.68 bcf per day for the seven authorized licenses exceed Canada's forecast current domestic and export consumption of 13.1 bcf per day, which the NEB forecasts will drop to 11.4 bcf per day in 2015, reflecting the impact of the rapid growth of shale production in North America. Canada's peak consumption year was 17 bcf per day in 2005.

Oliver said the government of Prime Minister Stephen Harper "supports energy projects that will create jobs and generate economic growth in Canada for future generations."

He said the government is "aggressively working to reach new markets for Canadian natural resources," provided the projects are safe for Canadians based on an "independent, science-based environmental and regulatory review." ●

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NGL LIMITS

Light hydrocarbons

NGL consists of a series of relatively light, volatile hydrocarbons such as butane, pentane and octane that contain multiple carbon atoms per molecule but fewer carbon atoms than the typical hydrocarbons in crude oil. The NGL hydrocarbons have a higher market value than methane, the hydrocarbon that forms the primary component of natural gas and that contains just one atom of carbon per molecule. The North Slope oil producers recycle natural gas produced from the oil fields back into field reservoirs, to maintain reservoir pressure and hence sustain oil production — natural gas is too volatile for exporting mixed with oil and would have to be exported through a specialized gas line.

Some NGL, separated from the fluids flowing from oil wells, is used in a material called miscible injectant, a hydrocarbon solvent injected into oilfield reservoirs for enhanced oil recovery. The remainder is mixed with the sales oil streams delivered to pump station 1.

And, to maximize the volume of NGL that can be shipped down the pipeline without hitting the vapor pressure limit, it is possible to distil out the heavier and less volatile NGL components, preferentially mixing these with the exported crude oil, rather than exporting the lighter fractions. The lighter components, including propane, are preferentially used to make miscible injectant, Malvick said.

The granddaddy of the NGL processing systems on the North Slope is in the massive Prudhoe Bay field Central Gas Facility, the facility that compresses huge volumes of natural gas for re-injection into the field. A unit within the facility separates the heavier NGL components for injection into the Prudhoe Bay sales oil stream at a facility adjacent pump station 1 — a monitoring system ensures that the vapor pressure of the resulting fluid does not exceed the 14.2-pounds-per-square-inch limit, Malvick said. And some of the NGL from the Central Gas Facility goes to the Kuparuk field for enhanced oil recovery, he said.

—ALAN BAILEY

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PLANT ASSESSMENT

mostly for export to foreign markets in the Pacific region.

At closing, the plant was "properly mothballed" and has been maintained to allow for a safe restart of operations, the RFP said.

Appraisal specifics

The RFP said AIDEA is seeking qualified firms to value the Agrium plant including all equipment and surrounding land and buildings.

The factory sits on 125 acres, and has its own power plant and a dock for loading cargo ships.

AIDEA estimates a budget of between $50,000 and $150,000 for the appraisal project. The appraiser is to value the plant whether sold piecemeal or intact.

Agrium will provide access to the plant and will make people available for inspection of the assets and to answer questions, the RFP said.

The appraiser will have six weeks to do the job under the AIDEA contract. ●

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GOVERNMENT

BSEE seeking oil spill research proposals

The Bureau of Safety and Environmental Enforcement, or BSEE, has announced that it is seeking proposals for new oil spill response research projects. The agency says it has $7 million available in 2014 to support projects that it selects. The deadline for submission of proposals is Jan. 20.

Research topics must fit within 10 general subject areas that BSEE has specified. These subject areas include cataloguing key research programs, recommendations and findings; developing planning standards for the use of dispersants and burn boom; the use of remote sensing for detecting spilled oil; the mechanical recovery of chemically treated oil; making some enhancements to BSEE's Ohmsett testing facility; developing "smart" skimming technologies; and establishing definitions for the readiness of oil spill response equipment.

"This announcement continues and enhances BSEE's commitment to a comprehensive research program dedicated to improving oil spill response operations," said BSEE Oil Spill Response Division Chief David Moore when announcing the request for proposals. "Through efforts such as this, we hope to spur further innovation and to improve upon the techniques and technology available to respond to potential oil spills."

Further information is available at www.FedBizOpps.gov

—ALAN BAILEY

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INTERIOR GAS

tified during the proceedings that the distribution build-out would impact demand from a North Slope liquefied natural gas plant as well as the cost of gas.

The project aims to truck North Slope LNG into the Interior by late 2015.

AIDEA is expected to choose a private sector partner for the LNG plant in January. The three candidates are MWH Americas Inc., Spectrum Alaska LLC and Pentex Alaska Natural Gas Co. LLC, which is the parent company of Fairbanks Natural Gas.

"We are here to work with all the utilities as this project moves forward. We look forward to working with (Interior Alaska Natural Gas Utility) and the other utilities to help make this project a success for Fairbanks," AIDEA spokesman Karsten Rodvik told Petroleum News.

The Fairbanks Natural Gas proposal imagined "essentially full conversion to natural gas in 2025" and included 3 billion cubic feet per year going to GVEA starting in 2015. The RCA said, "There is no support in the record for the assertion that (the local oil refinery) Flint Hills or others are potential industrial customers of (Fairbanks Natural Gas)."

While Fairbanks Natural Gas testified it would build out its grid without an industrial customer if it had enough supply and funding, the utility "did not present any revisions to its build-out plan to reflect a build-out without industrial load," according to the RCA.

Additionally, GVEA Chief Executive Officer Cory Borgeson testified that his utility expected to need less than 3 bcf per year because of a coal plant coming online in 2015.

The testimony doomed the Fairbanks Natural Gas proposal in the eyes of the RCA.

Even so, the RCA said it made "no negative finding" about how Fairbanks Natural Gas has served its existing area. Noting the "significant customer base available" in that area, the RCA said it "expects" the utility to expand its service "as gas becomes available."

The Interior Alaska Natural Gas Utility has often said Fairbanks Natural Gas' inability to serve all the customers within its existing service area should disqualify it for expansion.

Fairbanks Natural Gas said its inability to expand as envisioned was the result of supply shortages in Cook Inlet, and would be solved by the same North Slope gas supply underpinning its proposal to expand into other areas of the Fairbanks North Star Borough.

The RCA approved the Interior Alaska Natural Gas Utility plan for several reasons.

The Interior Alaska Natural Gas Utility based its design on AIDEA models, committed to building out its system within six years and promised to invest all profits in plant.

Among the criteria for any utility application is the ability of the utility to pay for its proposed operation. The RCA said the Interior Alaska Natural Gas Utility had "sufficient financial backing" for the project using loans, bonds and grants and municipal financing.

Fairbanks Natural Gas had often claimed that the Interior Alaska Natural Gas Utility lacked the financial wherewithal to complete its build-out — 663 miles in six years.

Under state statute, Interior Alaska Natural Gas Utility is exempt from regulation. The utility has said it would voluntarily accept regulation, but the RCA said the Fairbanks North Star Borough Assembly must first approve that distinction for it to become applicable.

Throughout the proceedings, the Interior Alaska Natural Gas Utility asked regulators to attach conditions to any certificate it issued for the region. Those conditions would have required either successful utility to commit to targets for scheduling, costs and construction standards, as well as mandatory annual reporting to ensure compliance.

The RCA declined to attach those conditions to the Interior Alaska Natural Gas Utility certificate, but said, "We construe its advocacy for those conditions as commitments to abide by the conditions it requests," adding that the utility "has pledged to fulfill the promises it made to the people of the (Fairbanks North Star Borough). The citizens, voters, and media of the community will participate in holding its leaders accountable."

The decision requires Interior Alaska Natural Gas Utility to maintain five days' worth of liquefied natural gas supplies in Fairbanks to protect the area from supply disruptions.

The RCA decision also addressed some procedural issues.

A major issue in the case was whether the applications were mutually exclusive.

While not identical, the proposed service areas greatly overlapped, and both Fairbanks Natural Gas and the Interior Alaska Natural Gas Utility asked for exclusive certificates, largely because it would be impractical for the utilities to build competing infrastructure.

Throughout the deliberations, the RCA avoided calling the two projects "mutually exclusive," a designation with regulatory consequences. Specifically, the RCA is allowed to divvy up two "mutually exclusive" service areas, giving some sections to one utility and some to the other. Also, while public utilities are exempt from certain regulations, the exemption is waived when a public utility directly competes against a private utility.

The prospect of dividing the service area came up in this case, but the RCA ruling granted only one certificate to make it easier to integrate into the Interior Energy Project.

The RCA also addressed its timing, which had been a point of criticism.

In an editorial in the Fairbanks Daily News-Miner in early October, Gov. Sean Parnell said the questions in the service area case "deserve significant, but prompt consideration," adding: "For the sake of Interior Alaskans' skyrocketing energy bills, the process cannot be drawn out. If it is, the overall success of the project could be at stake."

Fairbanks Natural Gas and the Interior Alaska Natural Gas Utility filed their applications in April and the RCA initially found both applications to be complete. The RCA is typically given six months to make a ruling in a case such as this one. But, the RCA noted, both parties later changed their applications. "This posed a challenge for the parties as they attempted to respond to each other's applications and the constantly changing applications were a challenge for this commission as we reviewed the record."

AIDEA had said the delay would not harm its timeline.

The applications were not truly final until Oct. 3, after a long hearing on the case, according to the RCA. "Consequently, our evaluation of the applications took place in a much shorter timeframe than the six months contemplated by statute," the decision said.

The decision aimed to cool heads, too.

The case became quite pointed, particularly during the hearings.

The RCA called out "insinuations," "assertions" and "accusations" the Interior Alaska Natural Gas Utility made against Fairbanks Natural Gas during the proceedings — such as questioning Cook Inlet supply shortages, or claiming Fairbanks Natural Gas' decisions caused bodily harm in Fairbanks — as being "without merit." The RCA said it made its decision entire based "solely on the facts and law discussed in the body of this order." ●

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MILLER ANSWERS

at the company's next annual meeting, expected to be held in late March.

Miller is based in Knoxville, Tenn., and is listed on the New York Stock Exchange. Its main business is in Alaska, where subsidiary Cook Inlet Energy LLC operates a collection of oil and gas properties on the inlet's west side.

Miller's overall production is small at just over 4,000 barrels of oil equivalent per day.

The company has borrowed aggressively for Alaska drilling operations and acquisitions.

The dissidents aimed much of their criticism at Scott Boruff, Miller's chief executive, and David Voyticky, chief financial officer.

"Executives with relevant experience, such as David Hall who runs the operations in Alaska and has 20-plus years of experience in Alaska, have been excluded to a great extent from the senior executive team charged with leading the company," the letter said. "In fact, the business is run by absentee executives in Tennessee and California who appear very interested in strategies aimed at undermining corporate governance while lining their own pockets and those of their select friends and followers, but neither understand nor seem particularly interested in the operations on the ground in Alaska. We believe, neither Mr. Boruff nor Mr. Voyticky have spent any considerable time in Alaska and in fact have spent more than 95% of their time far removed from the company's most valuable asset."

'A very strong record'

The dissident group is led by Bristol Capital Advisors LLC and Lone Star Value Management LLC, and says it represents about 4.7 percent of Miller's outstanding common stock.

The group alleges excessive executive compensation, mismanagement, personal use of corporate assets, poor board oversight, weak accounting and "massive shareholder dilution."

Miller defended itself with its Dec. 19 response.

"We have a very strong record of creating shareholder value over the last several years," the response said, noting the price of Miller's common stock had increased more than 120 percent for the year prior to a decline resulting from the dissident letter.

Miller is a small oil and gas producer in Tennessee. The company's profile began a sharp rise following acquisition of the Alaska properties in late 2009, with its penny stock jumping from the OTC Bulletin Board to the Nasdaq exchange and finally to the New York Stock Exchange. Miller closed on Christmas Eve with a share price of $7.25 and market capitalization of $323 million.

The company's Alaska subsidiary, Cook Inlet Energy, operates the Osprey offshore platform and the onshore West McArthur River oil field. ●

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MAC STIRRINGS

ExxonMobil) and Niglintgak (Shell) — could still be developed.

He said Kruger's thoughts were not just "dreamed up. They are the best news we've had on the project in some time."

"Just the fact that the proponents are still interested in constructing that pipeline is good news. It's five or 10 years out, but it's something that we can hopefully look forward to for getting Mackenzie gas to market," he said.

Ramsay said that if exploration activity in the Central Mackenzie Valley that is focused on the Canol shale oil prospect near Norman Wells results in commercial development, additional amounts of natural gas and natural gas liquids would spin off from the oil extraction.

He suggested that could "enter into the economic viability of the (MGP) itself."

Ramsay also noted that the transfer of regulatory power from the Canadian government to the NWT, scheduled for April 1, could see the territorial government use its size to avoid long, drawn-out regulatory approvals.

"We're not some big, cumbersome bureaucracy. We can see the direct impact that decisions are going to have on people, on the economy and on our environment and we can act accordingly," he told the newspaper.

He suggested it's more likely that Mackenzie gas would feed LNG facilities in British Columbia, which could mean a further boost in MGP costs to C$20 billion.

—GARY PARK

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