Petroleum news

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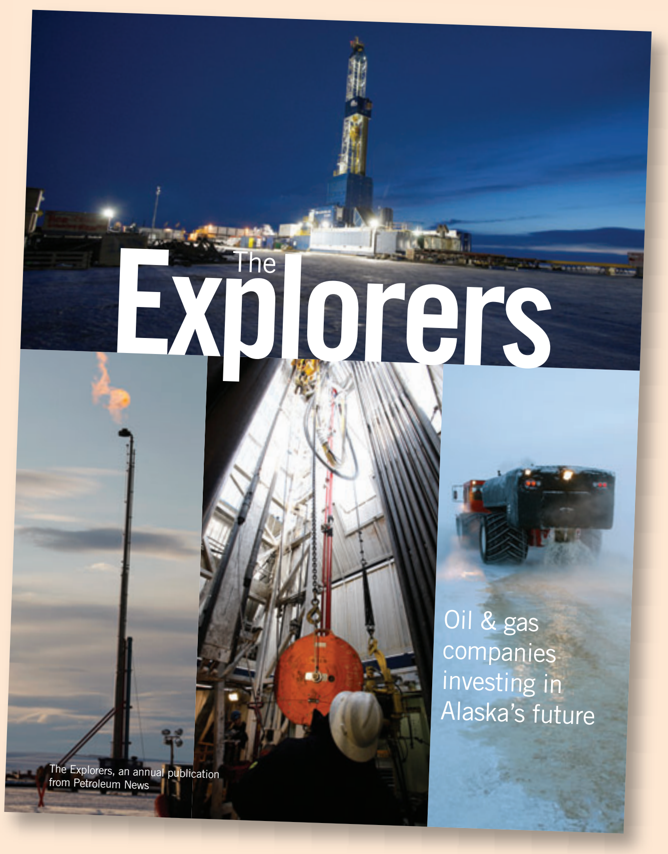
page 10 Down for 3 years, eastern North Slope Badami field brought back on Nov. 5

The Explorers magazine enclosed



Inside this issue of Petroleum News is the latest issue of The Explorers magazine, which features oil and gas companies investing in Alaska's future.

Hewitt drops N. Aleutian leases; Armstrong adds North Slope acres

Armstrong continues to amass a major land position on Alaska's central North Slope.

The Denver-based independent recently acquired five leases from the Italian major Eni Petroleum, according to lease reports from the Division of Oil and Gas. Through the deal, Armstrong acquired 100 percent working interest and 80 percent royalty interest in the leases.

The leases cover 12,726 acres adjacent to the southern boundary of the Kuparuk River unit and are also adjacent to dozens of leases that Armstrong, through its North Slope subsidiary 70 & 148 LLC, acquired in lease sales and private deals over the past year.

The five leases expire on June 30, 2012, and include ARCO's Winter Trail No. 1 well.

Armstrong has not yet announced its plans for the central

see **ARMSTRONG** page 19

BP layoff rumors overstated; owners may see judge promoted

THERE HAVE BEEN RUMORS CIRCULATING about BP and its contractors laying off a significant number of employees in Alaska.

According to BP's Alaska spokesman Steve Rinehart those rumors are inaccurate.

On Nov. 9, Rinehart told Petroleum News that normal seasonal layoffs have affected about 110 contractor employees; plus another 30 employees were cut because of a change in how the company does well work. (See related story about BP sale on the bottom of page 1.)

"While a few employees are coming and going all the time, we are not conducting a systematic BPXA staff reduction," Rinehart said in an e-mail. "As you know, the

see **INSIDER** page 23

EXPLORATION & PRODUCTION

Why not buy jack-up?

Buccaneer proposing consortium to buy a mobile drilling rig for Cook Inlet

By ERIC LIDJI
For Petroleum News

Why rent, when you can buy? For nearly two decades, exploration companies have failed in effort after effort to contract a jack-up rig for use in the waters of the Cook Inlet, in Southcentral Alaska. So Buccaneer Energy Ltd. wants to try something new: buy the rig and rent it out locally.

Buccaneer recently created two entities: a consortium called Kenai Offshore Ventures LLC and a new operating company. Kenai Offshore Ventures would own the rig and bring in revenues by leasing it to the operating company. The operating company in turn would bring in revenues by charging a day rate to local operators for drilling services.

Buccaneer said Kenai Offshore Ventures has indentified at least five years worth of work for the rig, "ranging from the mid-sized operators to the majors," as the company phrased it in a Nov. 10 presentation to the Kenai Chamber of Commerce. The work includes new exploration drilling, infill drilling at existing fields and plug and abandonment projects.

Buccaneer said Kenai Offshore Ventures has indentified at least five years worth of work for the rig, "ranging from the mid-sized operators to the majors."

Buccaneer said it is prepared to commit in writing to a one-year or two-well drilling program, using the jack-up rig to drill exploration wells at the two offshore plays it owns in the upper Cook Inlet: the proposed Southern Cross and Northwest Cook Inlet

see **JACK-UP RIG** page 24

FINANCE & ECONOMY

$1.7 million BP fine?

Alaska asks court to award civil penalty for 212,252-gallon Prudhoe spill in '06

By WESLEY LOY
For Petroleum News

Lawyers for the State of Alaska are asking a judge to approve a civil fine of nearly $1.7 million against BP for the record North Slope crude oil spill in 2006.

In a motion filed Nov. 8 in Superior Court in Anchorage, the lawyers are requesting a "base oil spill penalty" under a state statute that sets out a formula for calculating such a penalty for large crude oil discharges.

For spills in excess of 18,000 gallons, the statute specifies a penalty of $8 per gallon.

The BP spill was 212,252 gallons, so that figure times $8 per gallon equals an overall penalty of $1,698,016.

This is the amount the state lawyers are asking the court to approve. And they say no argument exists for why BP shouldn't pay the penalty, as the company already has acknowledged liability for it.

The lawyers say "there are no genuine issues of material fact" and thus the state "is entitled to summary judgment."

Small part of billion-dollar case

The requested civil fine is only a small part of the overall bundle of claims the state is pursuing

see **SPILL FINE** page 27

ANALYSIS

BP sale more than rumor?

TNK-BP strong candidate for Alaska assets, but cost-cutting might not be about sale

By KAY CASHMAN
Petroleum News

Is BP selling its oil and gas assets in Alaska? That's the billion dollar question.

The company's recent behavior suggests BP is marketing some or all of its Alaska assets, the largest of which is BP Exploration Alaska, or BPXA, in order to cover liabilities from its Gulf of Mexico Macondo well disaster.

Which company is top contender for an acquisition of some of BP's Alaska assets? Petroleum News' analysis puts TNK-BP, Russia's third largest oil producer, at the top of the list.

What does BP have to say about that? The compny is not talking, but TNK-BP, a 50 percent BP-owned joint venture with aspirations to grow internationally, had something to say Oct. 11 in response to a PN query about the significance of TNK-BP officials who have made recent trips to Alaska to reportedly study BP assets for a possible purchase. TNK-BP's Press Secretary Dmitry Sergeev was asked to verify his company's interest in acquiring BP's Alaska assets or complete subsidiaries.

Here is what he had to say: "TNK-BP's goal is to become a global leader amongst private oil and gas companies and a Russian industry leader, with a clear focus on stability and renewal of resources, as well as operating efficiency. International expansion will play a key role in TNK-BP's growth strategy. In its drive to diversify, the company needs to pay particular attention to regions where it has strengths from both the political and business points of view.

see **BP SALE** page 25

contents

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● ALTERNATIVE ENERGY

A storm blows up over wind power cost

CIRI and power utilities disagree over cost of integrating Fire Island wind power into the Railbelt power grid; pricing also an issue

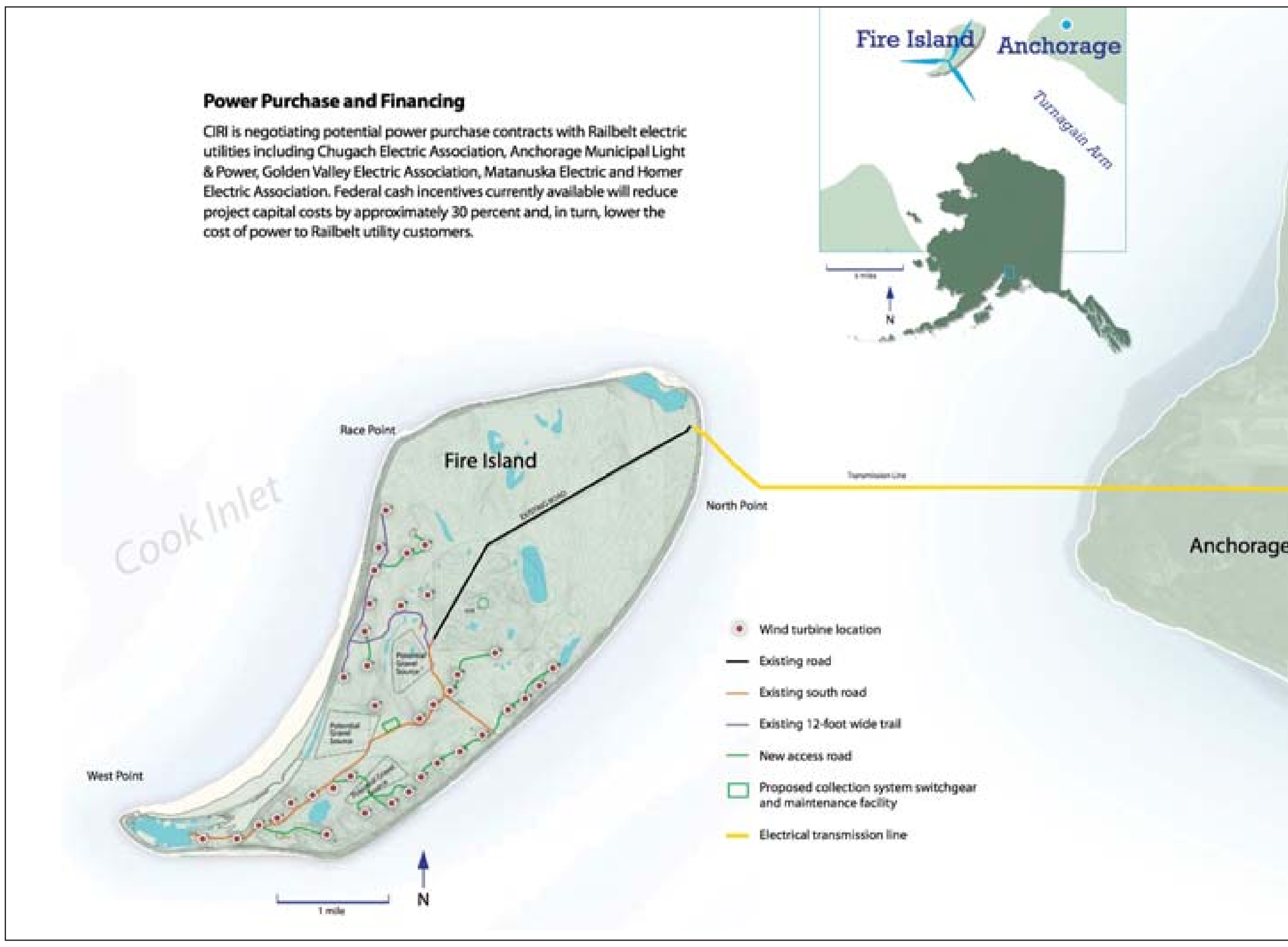
By **ALAN BAILEY**
Petroleum News

Just as Cook Inlet Region Inc. is running short of time to obtain utility power purchase agreements for it planned 52.8-megawatt Fire Island wind farm, offshore Anchorage, the Native regional corporation has run into a disagreement with the Alaska Railbelt utilities over the likely cost and technical risks of integrating power from Fire Island into the Railbelt electricity grid.

CIRI has said that its Fire Island wind farm could produce enough power to supply about 17,000 homes and thus reduce local natural gas demand by 3 to 4 percent.

But in a letter dated Oct. 25 to the Regulatory Commission of Alaska, Brian Newton, CEO of Golden Valley Electric Association, expressed the joint concerns of the six utilities that operate the Railbelt grid, saying that while the utilities support the principle of using renewable energy sources, the full cost of obtaining power from Fire Island has not been fully analyzed.

"The issue of great concern involves identifying and allocating the cost of integrating power generated from renewable resources into the Alaska Railbelt grid in a manner that the reliability of the Railbelt electric grid can be maintained," Newton wrote.



COURTESY CIRI

Fluctuating power

The core issue that the utilities are raising is the fluctuating power output from wind turbines, as the wind driving the turbine blades changes in strength — the utilities operating the grid would have to accommodate the power fluctuations, by for example varying the power output from gas-fired power stations.

And that would cost money.

"To be clear, we are not in favor of obtaining electric power at any price or incurring significant system-related investment costs and forcing that cost on to our individual customers," Newton wrote.

An analysis of potential Fire Island wind energy integration costs, commissioned by Southcentral utility Chugach Electric Association, has concluded that the integration cost would amount to around $100 to $110 per megawatt hour of wind-generated power, a cost that CIRI vehemently disputes, Ethan Schutt, CIRI's senior vice president of land and energy development, told the Anchorage Mayor's Energy Task Force on Nov. 3.

Schutt said that CIRI had already investigated the integration cost and, recognizing the high cost of doing business in Alaska, had suggested a worst-case scenario in which that cost would amount to three times the highest cost of similar wind-power integration in the Pacific Northwest.

But that estimated cost is still only about a quarter of the estimate from the Chugach study, with the integration cost estimated in the study being 20 percent higher than the cost of the wind power itself, Schutt said.

"That's ridiculous. We're not ridiculous people," Schutt said, commenting that CIRI would walk away from the project if it thought that the integration costs were that high.

Cost assumptions

Schutt said that it appeared that the Chugach study assumed that the wind farm would, for example, cover the entire cost of stored gas backup capabilities at Chugach power plants, whereas backup facilities would have wider application than just accommodating power fluctuations from Fire Island. Costs need to be spread across all who benefit from the facilities, Schutt said.

And CIRI does not agree with the assumptions that the Chugach study appears to have made about the way in which the varying output from the wind farm would be accommodated, said Dana Zentz, vice president of Summit Power Group and a CIRI consultant.

Schutt also rejected Newton's implication that integration of the Fire Island wind farm into the Southcentral electricity grid would jeopardize the reliability of the grid. Power from the wind farm would represent little more than 3 percent of the total power supply into the grid, a supply level far short of the 20 percent level at which uncertainties over grid stability might arise, Schutt said.

Asked for Chugach's response to CIRI's position on the cost of integrating Fire Island power, Phil Steyer, Chugach's director of government relations and corporate

see **WIND FARM** *page 20*

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● LAND & LEASING

Escopeta wants stay on Kitchen Lights

As appeal extends beyond deadline for curing default at offshore unit, Escopeta asks the court to put state proceedings on hold

By ERIC LIDJI
For Petroleum News

Escopeta is asking the Alaska Superior Court to put the Kitchen Lights unit on hold until the company's appeal of a state ruling on the Cook Inlet acreage reaches a resolution.

A stay would prevent the Alaska Department of Natural Resources from terminating the unit, which is in default, and taking back any of the unitized leases that have expired.

Escopeta is challenging that default notice, as well as DNR's proposed cure: a $4 million security deposit. The deadline for Escopeta to put down that security deposit and cure the default on the unit passed in late October, while the case has been on appeal.

Escopeta believes the stay is justified for three reasons: It believes the state didn't have the right to put the unit in default or to require a security deposit as a cure; it believes the termination proceedings would cause Escopeta "irreparable harm"; and it believes that re-leasing the acreage would cause significant confusion unless the appeal is resolved.

Escopeta made its argument for a stay based on many of the same claims it made in its 24 points of appeal filed back in September when it brought the case against the state.

The state has not yet filed its response to Escopeta's motion.

A decade of trying to drill

Generally speaking, the debate at Kitchen Lights is about what path forward would most likely lead to offshore exploration drilling in Cook Inlet. The potential answers are numerous and conflicting, but generally fall into two categories: giving Escopeta additional time to arrange a drilling program or putting the leases back up for sale.

Although Escopeta is appealing DNR's July 19 decision to put the Kitchen Lights unit in default, Escopeta's efforts to develop that acreage go back more than a decade.

Escopeta arrived in Alaska in 1994, but didn't begin amassing a major acreage position in the waters of the upper Cook Inlet until lease sales around the turn of the century.

Convinced that its leases overlaid major undiscovered oil and gas fields, Escopeta announced plans to explore the area, known at the time as Kitchen and East Kitchen.

It proved very challenging, though, to arrange an offshore drilling program in Cook Inlet. It required a special mobile drilling unit called a jack-up rig, a heavy-lift vessel capable of bringing that rig to Alaska and a waiver of the federal Jones Act that requires goods bound for U.S. ports to be carried on ships flagged and built domestically. In 2006, Escopeta came closer than any other company in decades, securing all three of those pieces, but then a partner backed out, forcing Escopeta to find new investors.

Escopeta believes the stay is justified for three reasons: It believes the state didn't have the right to put the unit in default or to require a security deposit as a cure; it believes the termination proceedings would cause Escopeta "irreparable harm"; and it believes that re-leasing the acreage would cause significant confusion unless the appeal is resolved.

The state formed the Kitchen unit in 2007, but put the unit in default at the end of the year when Escopeta missed a drilling deadline. The state ultimately gave Escopeta until the end of 2008, but as that deadline approached without a rig bound for Alaska, the state ultimately came up with an alternative idea: combining the holdings of Escopeta and two other independents — Pacific Energy and Renaissance — into a single, giant unit.

That unit became Kitchen Lights, owned and operated by Escopeta. The state gave Escopeta until June 30, 2010, to have a rig bound for Alaska to drill by Dec. 31, 2010.

In May 2010, though, Escopeta asked for a six-month extension to its work commitments. In its motion for a stay, Escopeta said it bore the brunt of two "unexpected, once-in-a-lifetime events," the federal government's announcement of critical habitat designations for Cook Inlet beluga whales and BP's oil spill in the Gulf of Mexico.

In its motion, Escopeta said that the habitat listing placed enough uncertainty over Kitchen Lights that a potential investor, Vetra Group, backed out of a partnership.

Escopeta also said it lost a jack-up rig contract with Pride International because, in the wake of the BP oil spill, "Pride International's insurer insisted on a number of additional, new requirements and conditions that eventually made the contract not feasible."

Despite these issues, the state put the Kitchen Lights unit into default in mid-July, giving Escopeta three tasks to keep the unit and the leases: First, give the state a $4 million security deposit on a jack-up rig within 90 days. Second, have the rig headed to Alaska by the end of February. Third, drill an exploration well by the end of September 2011.

Escopeta appealed that ruling in late August. ●

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● GOVERNMENT

House, Senate Working Group organize

By KRISTEN NELSON

Petroleum News

Both majority and minority caucuses in the Alaska House have organized for the 27th Alaska Legislature, which convenes Jan. 18 in Juneau.

The Senate Bipartisan Working Group, which announced leadership positions earlier in November, has completed committee assignments.

For the Republican-led majority in the House, Mike Chenault, R-Nikiski, returns as speaker. Alan Austerman, R-Kodiak, will be majority leader and Craig Johnson, R-Anchorage, will the chair of the Rules Committee.

Bill Stoltze, R-Chugiak/Mat-Su, will be co-chair of Finance for the capital budget and legislation and Bill Thomas, R-Haines, will be co-chair of Finance for the operating budget.

Peggy Wilson, R-Wrangell, will be majority whip and Reggie Joule, D-Kotzebue, will be House chair of the Bush caucus.

"We struck a regional balance, same as last organization," Chenault said in a Nov. 6 statement. "It's important, not only among caucus members, but also within the leadership team." He said he looks forward to "healthy debate" in Juneau.

The missing Republicans

In a Nov. 8 statement, House Republican leadership explained the absence from leadership and committee assignments of Kyle Johansen of Ketchikan, the current House majority leader, and Charisse Millett of Anchorage, who currently co-chairs the House Energy Special Committee.

Chenault said Johansen won re-election as House majority leader, but Millett didn't get the position she wanted as chair of the Legislative Budget and Audit Committee. Chenault said that after Millett failed to win the position as chair of LB&A, Johansen "proposed a deal to give up his position (as majority leader) and give Rep. Millett a seat on the House Finance Committee. The Caucus did not like that idea, so both representatives walked out of the organization."

Apparently there were accusations that Republicans ceded control by bringing rural Democrats into the caucus.

"We caucused with three rural members and former representative Richard Foster in the past, and both Rep. Millett and Rep. Johansen had no problem with it then. This is simply a situation where a pair of members did not like the choices their colleagues made concerning the make-up of the Majority Caucus," Chenault said.

Austerman, the newly elected majority leader, said Johansen and Millett "had the same opportunity as anyone else: to go through the normal caucus process to earn seats by vote, but they chose to make demands after the fact instead."

"We are committed — as a caucus — to including the voices and viewpoints of all regions of Alaska in making policy and fiscal decisions," Austerman said.

Johnson, the new Rules chair, said: "The only promise I made regarding the Rules Chairmanship was that I wouldn't unilaterally block any caucus priority legislation." He said he would never promise action on specific legislation in return for a position.

"That is not ethical — and I never would do that, period," Johnson said.

He said House Republicans have caucused with rural Democrats in the past "and it has been a strength. Frankly, I believe that they provide ample balance and perspective to our caucus and am thankful for their voice in caucus matters."

House committee chairs

Other committee chairs for the House are: Cathy Munoz, R-Juneau, Community and Regional Affairs; Alan Dick, R-Stony River, Education; Wes Keller, R-Wasilla, Health and Social Services; Carl Gatto, R-Palmer, Judiciary; Kurt Olson, R-Soldotna, Labor and Commerce; Paul Seaton, R-Homer, and Eric Feige, R-Chickaloon, co-chairs of Resources; Bob Lynn, R-Anchorage, State Affairs; and Peggy Wilson, R-Wrangell, Transportation.

Neal Foster, D-Nome, and Lance Pruitt, R-Anchorage, will co-chair the Special Committee on Energy; Mike Hawker, R-Anchorage, will chair the Legislative Budget and Audit Committee; and Bob Herron, D-Bethel, will be vice-chair of the Legislative Council.

House Democrats

The House Democratic caucus announced its leadership positions Nov. 5.

Beth Kerttula, Juneau, returns as minority leader; Berta Gardner of Anchorage will be minority whip; and Max Gruenberg of Anchorage will be the House minority floor leader.

Senate Bipartisan Working Group organization

Senate leadership positions announced by the 16-member Senate Bipartisan Working Group, in addition to president (Gary Stevens, R-Kodiak), majority leader (Kevin Meyer, R-Anchorage), Rules chair (Johnny Ellis, D-Anchorage) and Finance co-chairs (Lyman Hoffman, D-Bethel, and Bert Stedman, R-Sitka) announced previously, include the following committee chairs:

Joe Paskvan, D-Fairbanks, and Tom Wagoner, R-Kenai, co-chairs, Resources; Hollis French, D-Anchorage, Judiciary; Linda Menard, R-Wasilla, Legislative Council; Donny Olson, D-Nome, Community and Regional Affairs; Kevin Meyer and Joe Thomas, D-Fairbanks, Education co-chairs; Bettye Davis, D-Anchorage, Health and Social Services; Dennis Egan, D-Juneau, Labor and Commerce; Bill Wielechowski, D-Anchorage, State Affairs; Albert Kookesh, D-Angoon, Transportation; Gary Stevens, World Trade; Bill Wielechowski, Joint Armed Service; and Hollis French, Admin. Reg. Review. ●

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● PIPELINES & DOWNSTREAM

GVEA looking to increase pipeline rates

Fairbanks electric utility operates crude oil pipeline that feeds two Interior refineries, Flint Hills is challenging the increase

By ERIC LIDJI
For Petroleum News

Golden Valley Electric Association is looking to increase the rates it charges to ship oil on a small pipeline in North Pole, but its main customer is challenging the request.

The Regulatory Commission of Alaska recently allowed GVEA, the electric cooperative for Interior Alaska, to temporarily increase rates nearly 25 percent on a refundable basis.

GVEA operates a 5.4-mile crude oil pipeline that connects the trans-Alaska oil pipeline to two oil refineries and GVEA's power plant in North Pole, three neighboring facilities.

GVEA said it has lost money on the pipeline two years in a row. It said that those losses came from higher operating costs, but also because a fund set up several years ago to pay for investment projects didn't work out as planned. As a result, GVEA said, it now has more than $3.1 million in unreimbursed expenses for "necessary capital improvements."

"Over the past few years, GVEA has not been achieving the level of margins from its Pipeline operations that the Commission authorized GVEA to earn," Thomas K. Hartnell, vice president of administrative services for GVEA, wrote in testimony to the RCA.

> *"Over the past few years, GVEA has not been achieving the level of margins from its Pipeline operations that the Commission authorized GVEA to earn."*
> **—Thomas K. Hartnell, vice president of administrative services, Golden Valley Electric Association**

GVEA is proposing one of two rate structures, a flat rate or a more traditional per barrel rate. GVEA prefers the flat rate, but offered the more traditional rate as an alternative.

The pipeline only serves two customers: Flint Hills Resources and Petro Star Inc., the owners and operators of the two oil refineries in North Pole. Flint Hills is by far the larger customer, though, accounting for more than 90 percent of the shipments on the pipeline.

Flint Hills claims that the increase is merely a way for GVEA to increase its operating margins, or the "profits" that a nonprofit cooperative collects to prove financial health.

Several tariff structures

GVEA built the pipeline in the mid-1970s as a way to take advantage of the trans-Alaska oil pipeline coming through the Interior and a new oil refinery planned for North Pole.

The cooperative, which is primarily an electric utility, saw the pipeline as a way to connect to a long-term lower cost fuel supply and to reduce fuel storage at its facilities.

Over the 33 years since GVEA began operating the pipeline, its customers have changed.

Earth Resources brought the 25,000 barrel per day refinery online in 1977, expanded its capacity to 45,000 bpd in 1980 and then sold control of the plant to Mapco Alaska Petroleum Inc. Mapco doubled capacity to 90,000 bpd in 1985 to accommodate more products and eventually expanded twice more, to an ultimate capacity of 215,000 bpd.

Williams Companies Inc. bought Mapco in 1998, but Flint Hill Resources Alaska, the current owner, bought the entire refining operation from Williams in July 2004.

In 1984, GVEA got a second customer when Petro Star Inc. built a second refinery, also in North Pole, to produce a different selection of petroleum-based products.

For the first 22 years of its operation, GVEA billed its customers under a special contract, charging an estimated monthly per-barrel rate that it trued-up at the end of the year.

In 1999, RCA required GVEA to set up a tariff, but the tariff resembled the contract, allowing GVEA to collect its costs and a margin each year from its two customers.

New method in 2003-04

Because of the difficulty predicting costs and throughput that system led to large payment swings, especially in the first quarter of the year, during the true up. Plus, GVEA expected the aging pipeline would soon need investment that wouldn't be covered under the tariff. So in 2003-04, GVEA and its shippers agreed on a new method.

In addition to the traditional per-barrel shipping rate, the new tariff included a capital improvement program. Under the program, the two shippers would approve the costs for capital projects and split up the payment based on their percentage of throughput. GVEA didn't worry about not getting approval "because of the cooperative nature of GVEA's dealings with the Shippers throughout the history of Pipeline operations," Hartnell wrote.

But shortly after implementing the program, Williams sold the facility to Flint Hills.

"Flint Hills has refused to enter into the agreements necessary to accommodate the Capital Investment Program," Hartnell wrote. This became a problem in 2008, when GVEA began two capital projects it saw as "necessary for proper Pipeline operation."

Hartnell wrote that discussions among GVEA, Petro Star and Flint Hills began in early 2008 and continued until GVEA filed its most recent tariff in September. While Petro Star agreed to move forward, Flint Hills did not, according to Hartnell.

So now, GVEA is proposing a rate structure similar to its original system: a flat monthly rate divvied up between the two shippers based on historic use, and adjusted annually.

Alternatively, GVEA is proposing a shipping rate of 3.54 cents per barrel, up nearly 25 percent from its current rate of 2.85 cents per barrel plus a capital improvement rider.

The RCA approved the 3.54-cent rate on a temporary basis while it studies the case.

The temporary rate goes into effect on Jan. 1.

Flint Hills challenges TIER

GVEA claims that the new rates would allow it to collect the margin that the RCA approved during its last rate case, but Flint Hills challenges that assumption. Flint Hills believes the "attempt to lock in a fixed dollar margin" at $934,370 would lead to a higher TIER for GVEA. A TIER, or times interest earned ratio, measures the ability of earnings to cover the interest owed on debt, and is a common metric in Alaska utility rate cases.

Flint Hills believes an "appropriate" TIER for GVEA's pipeline operations should be no higher than the TIER for its electric utility operations, and possibly much lower.

Because throughput is not expected to increase, Flint Hills believes it will end up paying more and more each year, as each barrel constitutes a larger share of the fixed margin.

GVEA is also concerned about throughput, saying that the lower temperature that accompanies the declining volumes of oil could lead to increased operations costs.

Capital improvement projects an issue

Flint Hills is also questioning the two capital improvement projects from 2008.

Although Flint Hills did not own the refinery in 2003, when GVEA and the shippers implemented the capital improvement program, Flint Hills said it doesn't know of any proof that its predecessor Williams "may have made any commitments to pay for any and all facilities that

see **GVEA** *page 7*

● LAND & LEASING

Donkel evaluating North Slope acreage

Fresh from sale of Cook Inlet holdings, Dan Donkel has high bids of almost $1 million in Beaufort Sea, North Slope lease sales

By KAY CASHMAN & KRISTEN NELSON

Petroleum News

In July Samuel H. Cade and Daniel K. Donkel (in partnership with others on some leases), sold 196,524 acres of Alaska state Cook Inlet oil and gas leases to Apache Corp., 60 leases scattered across the Cook Inlet basin from the Wasilla area to Anchor Point, both onshore and offshore.

After the sale to Apache, Donkel held less than 30,000 acres in state oil and gas leases.

But that changed in October, when Donkel was the apparent high bidder on almost 100,000 acres in the state's North Slope and Beaufort Sea areawide sales, with apparent high bids of almost $1 million.

Donkel had the second largest number of apparent high bids and the second highest bid total in the North Slope sale, taking 22 tracts for $608,000.

In the Beaufort Sea sale, Donkel was the big bidder, taking 13 tracts for $390,400.

A bidder since 1983

Donkel told Petroleum News in an e-mail that he was "very happy" with results of the lease sales.

"I have learned so much about Alaska's oil business since my first lease sale in the Cook Inlet in September of 1983," he said.

Donkel has been vocal through the years about how Alaska's oil and gas laws and regulations make it hard for small companies to become producers in the state. He is optimistic that that may change.

"I see this year's election as a game changer for the people of Alaska and the oil industry," Donkel said, and he hopes for changes that will encourage more oil and gas development in the state.

"In this 2010 election Alaskans have sent the message to both Democrats and Republicans that more oil and gas jobs and investment in Alaska are needed. As a result, the candidates are talking about making changes to bring investment from oil and gas companies from the around the world back to Alaska."

Donkel has frequently been a successful bidder in Alaska oil and gas lease sales, and has assembled acreage for development — but he has yet to be an operator in the state.

On his plans for this acreage, he told Petroleum News he might use Donkel Oil and Gas LLC to attract investment and drill the leases he acquired in the recent sales, or might "partner to bring … a new company into Alaska like I did with excellent oil companies like Forcenergy and others in the Cook Inlet over the last few decades."

Donkel said he would like to see the new Legislature pass "lower taxes and less burdensome regulation," which he said would cause Alaskans and those who choose to invest in Alaska's oil and gas industries to prosper.

He said he can't think of a better win-win than to match "Alaska oil and gas potential with the oil and gas investment dollars currently being spent in other jurisdictions worldwide."

His goal with the North Slope and Beaufort Sea acreage was to "help Alaska and Alaskans by reinvigorating exploration on the North Slope," Donkel said.

Cook Inlet work

Dave Gross, a consulting geologist who began work on Donkel's prospects after he left Chevron in 1992, told Petroleum News in an e-mail that chief among earlier successes were the Redoubt Shoal and Sterling gas fields.

He said Donkel's company, then Danco Inc., later Donkel Oil & Gas LLC, "identified the opportunity at Sterling and with a joint venture partner, we were successful in bringing the Sterling Gas Field into production. Our attempts to do the same with the Redoubt Shoal project were not successful."

Gross said that "after a long and expensive struggle it was deemed economically prudent to sell the entire project to an independent oil company and to retain an ORR (overriding royalty)."

Redoubt Shoal was sold to Forcenergy and after Forest Oil acquired Forcenergy's Alaska properties in 2000, the Osprey platform was installed at Redoubt and production began.

"Though the field was not developed in a manner I would have recommended," Gross said, "it still represents the first installed platform in the Cook Inlet in decades and I think will display its true potential under the care of its new owners."

Gross said that Donkel's "desire has always been to actively pursue and develop hydrocarbon prospects himself, but conditions being what they are in Alaska, he has been left with the business model of using the geologic and geophysical input from his consultants to acquire leasehold positions that contain good exploration prospects. Instead of going forward with these projects himself, Dan (Donkel) is forced to offer these opportunities to clients who have greater economic resources than he, but often lack the expertise and experience in the Alaskan oil industry to identify these prospects themselves."

'Moderate to high potential tracts'

Consulting geologist Don Brizzolara, who was with ARCO for 20 years, 1979-99, and with the Alaska Division

see **DONKEL** page 18

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GVEA

GVEA may construct on its own without prior agreement."

GVEA believes the capital projects undertaken in 2008 help both shippers. One project upgraded a connection to support capacity improvements to the Petro Star facility, while the other is a new metering station. GVEA expects both projects to be finished in 2011.

Flint Hills doesn't believe it should have to pay 90 percent of the cost of the projects.

"The new pipeline connects to the Petro Star refinery and is utilized primarily to serve the Petro Star refinery," Flint Hills wrote in filings with RCA. "Similarly, the new meter station is utilized to measure the quantity and quality of the petroleum stream leaving the Petro Star refinery. While Flint Hills appreciates that it benefits to some degree from accurate measurements of Petro Star's petroleum from an allocation standpoint, any such benefits do not justify charging Flint Hills for 90 percent of the cost of such meter."

Flint Hills and Petro Star have both asked to be party to the upcoming rate case.

Flint Hills is owned by Koch Industries, which also owns a stake in the trans-Alaska oil pipeline. The refinery has been struggling with poor economics in recent years. ●

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GOVERNMENT

Parnell reshaping gas line leadership

The resignations Gov. Sean Parnell requested of cabinet members will bring new leadership to the team developing a multibillion dollar North Slope natural gas pipeline, the Anchorage Daily News reported Nov. 10.

Parnell says he wants the team to work with state legislators to determine how the gas should be taxed. Major producers — ExxonMobil, ConocoPhillips and BP — say they won't commit to the project without tax certainty.

Parnell supports the gas pipeline project launched when Sarah Palin was governor, although his campaign opponents called it a failure and waste of taxpayer dollars.

Three team members to leave

Three key members of the natural gas pipeline team are among the commissioners whose resignations the governor has accepted: Resources Commissioner Tom Irwin, Revenue Commissioner Pat Galvin, and deputy Resources Commissioner Marty Rutherford, who led the team.

The gas project is still in early stages: Two competing pipeline companies — one led by BP and ConocoPhillips, the other led by TransCanada Corp. and ExxonMobil — say they have received conditional bids from prospective gas shippers but no firm commitments yet.

Under the state's plan, Palin granted a license to TransCanada, making the Canadian company and Exxon eligible for $500 million in state reimbursement for their spending to advance the pipeline. The state hopes to have the gas line built and producing gas by 2020.

—THE ASSOCIATED PRESS

● NATURAL GAS

Arctic natural gas vital ingredient

TransCanada CEO certain about need for northern gas within a decade; estimates Alaska project could be built for $3-$4 per mcf

By GARY PARK
For Petroleum News

TransCanada is a great believer in the need for gas of all kinds, not least from the Arctic, to meet long-term North American demand, but is also dropping some warning markers on how far its patience will extend with the Mackenzie Gas Project.

The obvious candidate to deliver gas from the Mackenzie Delta to northern Alberta, TransCanada said Nov. 3 that it is close to reassessing its role as banker for the Aboriginal Pipeline Group, which hopes to secure a one-third equity stake in the pipeline, if the project goes ahead.

TransCanada noted it has already advanced C$145 million to the APG to cover the group's share of regulatory costs.

Chief Executive Officer Russ Girling told analysts that TransCanada and the other co-venture companies — Imperial Oil, Shell Canada, ConocoPhillips Canada and ExxonMobil Canada — are hopeful the National Energy Board will "come to a positive conclusion," when it delivers its final verdict on the MGP application by either late this year or early 2011.

If the verdict is positive, all the stakeholders "have to sit down and determine when that gas will be economic to bring to market and when to make the investments," Girling said. "Stay tuned."

The company said the project timing after the NEB decision "continues to be uncertain."

"In the event the co-venture group is unable to reach an agreement with the (Canadian) government on an acceptable fiscal framework, the parties will need to determine the appropriate steps for the project," it said.

"For TransCanada, this may result in a reassessment of the carrying amount of the APG advances."

Gas prices, US economy

Girling also said that depressed gas prices and the depressed state of the United States economy will affect the timing of any gas pipeline out of the North Slope to the Lower 48.

Girling estimated a processing plant and pipeline to get Alaska gas to market could be built at a cost of $3-$4 per thousand cubic feet.

However, he said 2018-20 is the "probable time frame driver" for all of the large companies that are in Alaska, based partly on expectations that North American gas consumption could rise from 80 billion cubic feet per day currently to 90 bcf or greater in another 10 years.

Also influencing decisions on Arctic gas is the annual decline of 15-20 percent in conventional production rates, meaning a replacement of about 15 bcf per day is needed "just to stay even," he said.

Girling said that outlook accounts for the proliferation of new shale gas production, although the Barnett shale in Texas ramped up very quickly to 5 bcf per day and "appears to have leveled out."

He noted that the decline rate for shale gas is "pretty steep in the first couple of years, once you reach a run-rate production level."

Construction at $3-$4 per mcf

Over the next decade, he said the continent will need conventional gas, shale gas and no0rthern frontier gas, with Alaska as a primary driver given that a current reinjection rate of 7-9 bcf per day means there are no additional development costs associated with developing the state's gas resources.

Girling estimated a processing plant and pipeline to get Alaska gas to market could be built at a cost of $3-$4 per thousand cubic feet.

"So if you can land that gas in a $5 market you're getting a $1 netback, which would make the project economic even in the current market," he said, estimating it would take seven to 10 years to get

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ARCTIC GAS

through the regulatory process, design and build the necessary facilities.

Girling said large companies, rather than basing their decisions on today's spot prices, are evaluating where the market is likely to be in another 10 years. "If you want to hit that date, you have to start working today."

Shale outlook not certain

The importance of Arctic gas over the long term is even gaining added momentum from its supposed competition from shale gas.

The less-than-certain outlook for shale gas, despite its immense contribution to gas resources (it has tripled Canada's potential to 300 trillion cubic feet), has been reflected lately in British Columbia's sizzling Horn River shales, where large operators have responded to prospects of prolonged depressed gas prices by slowing their activities.

For TransCanada, unconventional gas underpins its hopes of carrying an additional 2 billion cubic feet per day by 2014, offsetting most of the projected decline in conventional production for its mainline system.

It already has strong commitments for its Groundbirch line (capacity of 1.1 bcf per day from the Montney play), Horn River (540 million cubic feet per day from Horn River) and Bison (400 million cubic feet per day from northern Alberta).

But key operators in Horn River are showing their edginess by either cutting back spending plans for 2011, or reviewing their budgets.

CNQ pulling back

Encana, Canadian Natural Resources (CNQ), Talisman Energy, EOG Resources, Apache and Devon Energy have all started pulling back from the basin without actually shutting down operations.

CNQ, which led the Canadian industry by shutting in volumes ahead of the price downturn two years ago, will direct most of its scaled-back gas spending in 2011 to preserving land tenure, said President Steve Laut.

"We believe shale gas production is real and it looks like shale gas reserves are real, but we don't think that's for sure yet," he said. "Shale gas might work at prices of $4 (per thousand cubic feet) but maybe only in the sweet spots and maybe only in the liquids-rich areas," where producers can sell gas liquids for $40-$50 per barrel.

Laut said CNQ can afford to hold its vast land base, with 8,000 drilling locations, until gas prices rebound. Neither will it ignore acquisition opportunities that can reduce operating costs once the assets are integrated into the portfolio. So far this year, the company has bought properties yielding 214 million cubic feet per day of gas and 9,000 barrels per day of liquids.

But the company will continue to lower its output from a current 1.285 billion cubic feet per day in 2011 and beyond during the low-price environment, which Laut believes could last another three to seven years.

Ditto for Talisman, Encana

Similarly, Talisman is taking a less aggressive approach to its shale gas except in its newly acquired stake in the Eagle Ford play of south Texas, where a high liquids content makes gas production profitable.

Chief executive John Manzoni believes it could take the North American gas market another year to "rebalance."

For now, he said an announcement is imminent on a "strategic" partner to share the costs of developing Talisman's "very large shale resources" in British Columbia.

Encana chief executive Randy Eresman said Canada's largest gas producer is slowing the near-term growth rate of its resource plays and expects to shortly offer asset packages for farm-in deals, even though he is unsure about prospects of a firm joint-venture deal with China National Petroleum Corp. for British Columbia.

Also US-based operators

The three dominant U.S.-based operators in British Columbia are all in a rethinking mode as they prepare 2011 budgets.

EOG chief executive Mark Papa said his company has a "good feel" for reserves and production potential for Horn River, but will take a "minimalist approach" to spending because of "very dismal North American gas conditions."

Apache chief executive Steve Farris said the C$370 million his company has spent in Horn River this year showed the reservoir was up to expectations, bringing 18 wells into production this year and scheduling another 12.

"Now it's a question of how do we balance our current capital against future opportunities," he said. "That's one of the hardest things we'll have to decide in 2011."

Devon Executive Vice President Dave Hager said minimal capital will be invested in Horn River next year because the basin's dry gas offers no liquids returns, but insisted the producing wells are performing "better than expected," indicating ultimate recovery of about 8 bcf per well. ●

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PIPELINES & DOWNSTREAM

BP probation for '06 oil spill set to expire

Unless federal attorneys make a move within the next few weeks, BP will come off probation for its big 2006 North Slope oil spill in 22 days.

The company pleaded guilty in 2007 to a misdemeanor violation of the federal Clean Water Act for the 212,000-gallon spill from a corroded pipe.

In the plea agreement, BP said that the spill was due to its own negligence, paid a $20 million criminal penalty and agreed to a three-year probation.

A federal judge signed the plea agreement on Nov. 29, 2007. The probation is scheduled to end on Nov. 29 this year.

BP declined to comment on its probation status the first week of November, and the company's probation officer did not return phone calls.

The plea agreement spelled out three achievements BP needed get off probation:

• The company had to make significant progress in replacing its North Slope oil transit lines, which had become aged and corroded.

• BP had to make significant progress on creating and running an integrity management plan for its North Slope infrastructure.

• The company had to make significant progress on a better system for detecting oil spills.

—ELIZABETH BLUEMINK
Anchorage Daily News

● EXPLORATION & PRODUCTION

Savant announces restart at Badami

Oil has started flowing again from the field following the drilling of a horizontal sidetrack and an exploration well last winter

By ALAN BAILEY
Petroleum News

BP EXPLORATION (ALASKA) INC.

The Badami oil field, the most easterly of the developed fields on Alaska's North Slope, went back into production on Nov. 5

The Badami oil field, the most easterly of the developed fields on Alaska's North Slope, went back into production on Nov. 5, Greg Vigil, an executive of Savant Resources, told Petroleum News. Savant and Arctic Slope Regional Corp. have been working with field operator BP since 2008 to bring the troubled field back on line, following a 2007 field shutdown intended to allow the field's reservoir to recharge with oil.

Earlier this year, Savant drilled a new exploration well, the B1-38, in the Badami unit, having also drilled a new horizontal sidetrack well in the Badami reservoir to test the use of horizontal drilling techniques to tease a higher oil flow rate from the field. The company planned to bring six wells on line in the startup, including production from an oil bearing horizon in the exploration well and production from the horizontal well.

The B1-38 well tested a prospect called Red Wolf involving the Kekiktuk formation, the formation that contains the oil reservoir for the Endicott field some miles to the west. Savant has remained tight lipped about its results from the Kekiktuk but has said that it found oil in a higher-level secondary target in the Cretaceous Killian sands. Oil production from the B1-38 well would come from that Killian sands oil pool, Vigil said in August.

The reservoir for the 120 million Badami field is in younger and shallower rocks in what geologists call the Brookian sequence.

Troubled history

The field has had a troubled history since it first went into production in 1998, with an anticipated 30,000-barrel per day startup production rate actually coming in closer to 18,000 bpd and then dropping to less than 3,000 bpd by early 1999. Faced with unsustainable winter oil flows down the Badami pipeline, BP shut the field in between February and May 1999. Then after unsuccessful attempts to improve production through the use of gas injection and the drilling of lateral wells from the field's original well bores, BP placed the field in warm shutdown between 2003 and 2005.

In 2007 BP shut the field in again, and the field remained dormant until this month's restart.

The production problems at Badami result from the highly compartmentalized field reservoir, formed from sands that fill a complex network of ancient submarine channels, interlayered with impervious shales. Initially, oil tends to flow at a good rate into an individual production well as individual sand channels are drained, but production then drops off as barriers between the channels inhibit the drained sand from recharging, a problem compounded by the somewhat viscous character of some Badami oil.

In 2006 BP proposed the use of horizontal wells to improve production rates by threading wells through the reservoir sands and thus increasing the reservoir volume exposed to each well bore. Savant and ASRC formed a deal with BP in 2008 to drill two wells and try the horizontal well production concept. ●

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Congratulations

Congratulations
Savant & **BP** on restart of Badami!

Badami, the easternmost developed field on the North Slope, has been restarted, thanks to the combined efforts of BP and partners Savant Alaska and ASRC. Photo taken summer 2008.

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● ALTERNATIVE ENERGY

RDC told it's time to move on hydro

More Southcentral hydroelectric power required to meet 50 percent renewable energy standard — and it will take at least a decade

By KRISTEN NELSON

Petroleum News

The Alaska Legislature has set a goal of producing 50 percent of the state's power from renewable energy by 2025. To meet that goal in Southcentral Alaska will require at least one large hydroelectric project, the Resource Development Council for Alaska was told at a Nov. 4 breakfast.

Presenters from Alaska Ratepayers Inc., MWH and the Alaska Energy Authority talked about the need for a large hydroelectric project in Southcentral Alaska and about some potential projects.

Rich Wilson, president of Alaska Ratepayers Inc., described the group's goals for electric power as affordable, predictable and long term. He said the group was founded in 2008 and "is composed of a small number of experienced Alaskans in business and government" who believe there is a need for grassroots support for policies supporting sustainable electric power.

> *"We have to do something about this — do something different," said Rich Wilson, president of Alaska Ratepayers, and Alaska Ratepayers believes hydroelectric power is a way to avoid rates rising further and possible power interruptions.*

"Electric energy is like roads: you can't get along without it," Wilson said.

Energy prices have risen in Southcentral as low-priced natural gas contracts end, he said.

"We have to do something about this — do something different," and Alaska Ratepayers believes hydroelectric power is a way to avoid rates rising further and possible power interruptions.

Wilson said Alaska Ratepayers' members have done an informal survey, talking to a lot of Southcentral stakeholders, and found "strong support" for hydropower in the utilities, among political leaders and among the general public.

He said the general reaction when people are asked about hydro is: "We should have done that a long time ago."

What is needed now?

Wilson said there needs to be an appropriation in the upcoming legislative session toward licensing a project and the Legislature needs to create "a state entity that has the authority and the resources to do the job," because putting a major hydro project in place will be a multiyear project that will continue through many legislative sessions and many governors.

He said $100 million would be needed to get Alaska down the road toward licensing, and a $2 billion to $2.5 billion investment by the state would be needed for a permanent levelizing of electric rates.

Wilson said that as with "just about every other hydro facility in the nation, either the state or the federal government needs to take the lead because it's a big chunk of funds."

Successful projects

Ed Carter, senior vice president with MWH, a global firm which engineers and constructs large hydro projects, said a decision to make a major investment in a project such as hydroelectric is done for several reasons: it's a renewable resource; hydropower "has a very long service life" and once in operation has low maintenance and operations costs; and a project can be set up to "accommodate changes over time that allow a project to be matched with future growth in the power systems that that hydro project is in."

Carter reviewed four existing large hydropower projects, including Bradley Lake in Alaska.

Bradley Lake, a state-owned and financed project, has been online for 20 years, he said.

The average cost of power generation for the project over 20 years has averaged 4 cents per kilowatt hour, Carter said.

He said BC Hydro, the British Columbia provincial utility, provides 95 percent of the energy used in British Columbia. Two of BC Hydro's big projects, Mica and Revelstoke, were both designed to accommodate changes over time by building the power stations to accommodate new units: 500 additional

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HYDRO POWER

megawatts go online at Revelstoke by the end of the year, Carter said, and a new 500-megawatt unit has been ordered for Mica which will go online in 2012.

"So the big point here is the flexibility," he said of the BC Hydro projects, "the foresight to look into the design and construction techniques that can be used so that a project can accommodate growth over time in the electric system."

Susitna River Watana site

There are three potential major hydro projects under consideration for Southcentral Alaska, said Bryan Carey, a technical engineer at the Alaska Energy Authority: Watana on the Susitna River, Chakachamna on the west side of Cook Inlet and Glacier Fork east of Palmer.

The Watana dam site on the Susitna River would have an installed capacity of 600 megawatts and could supply about 50 percent of Railbelt electricity.

The Watana site is some 30 miles above Devil's Canyon and Carey said few salmon go past Devil's Canyon.

"Some of the fisheries impacts would be positive," he said. Most fish don't spawn in the Susitna, but go up side rivers. The dam would reduce annual flooding and would also reduce silt. In that respect the Watana dam would provide a function similar to Kenai Lake, Carey said: The silt drops out in the lake and the Kenai River is clear downstream of the lake.

The flow downstream of the dam would have the same annual volume with modified seasonal timing.

He said old Federal Energy Regulatory Commission documents note that at Watana there would probably be "an improvement to salmon habitat on the Susitna River" because between Watana and where the Chulitna comes in would probably turn into "more of a clear-water type river similar to … the Kenai River."

Comparing Watana to the existing Bradley Lake project, Carey said Bradley Lake had no fish, but there were salmon downriver of the lake, closer to Kachemak Bay. He said fish biologists believe that the dam has improved the habitat for salmon downstream, with more salmon than before the dam was built and more species of salmon.

Glacier Fork, Chakachamna

The Glacier Fork dam would be north of Knik Glacier where there is a little canyon or valley. Carey said that is where the dam would be built, filling up the little valley.

The downside at Glacier Fork is that it's very narrow and doesn't have much storage capacity during the winter. Because the canyon is narrow you would be able to generate a lot of power from Glacier Fork, he said, "it's just that you'd tend to generate it during the summertime."

Chakachamna is currently listed with an installed capacity of 300 megawatts, Carey said, but it may be more or less because resource agencies have to approve environmental flows down the main river, and that could reduce energy from the project.

Possible energy from Chakachamna wouldn't be known until a couple of years of studies are completed, he said.

He said the environmental flows are a critical part of the project.

"To get a project licensed through FERC is extremely hard to do. The only thing that's harder to get licensed these days is a nuclear power plant," he said.

And resource agencies "have what's called mandatory conditioning" for hydropower, "and so they can put whatever conditions they want in the license and FERC cannot overrule." Whatever environmental flow the resource agencies want to go down the river, "then that's given; that will be in your license."

Right now salmon go up to Chakachamna Lake and travel through the lake to Lake Clark National Park, he said.

The Chakachamna project would use the existing lake and put in a power tunnel which would cut through about 11 miles to the McArthur River drainage. In addition to Lake Clark National Park to the west, downriver of both drainages is the Trading Bay Stage Game Refuge.

At best a decade

Benefits of hydropower include long life, "greater than 100 years"; the ability to design for expandability in the future; "clean, low-cost energy" with a predictable price into the future because the energy is produced in-state and isn't "subject to worldwide fluctuations in the price of fuel"; the ability to dispatch more energy in the winter when it's needed; and jobs and investment staying in Alaska, Carey said.

One of the two large projects, either Chakachamna or Watana, "are necessary if you want to achieve the state's 50 percent renewable energy policy — you're not going to get to 50 percent without one of these two large project," he said.

As to how long it would take, Carey said: "On an aggressive licensing and construction schedule — probably 10 to 12 years."

Why BC has hydro

Why does British Columbia have so much hydro and Alaska so relatively little?

Carter said it's because pioneers there pushed decisions a long time ago; great engineering feats were performed; and flexibility for expansion was designed into the structure.

Wilson said Alaska has not had to move to hydropower, but with declining natural gas in Southcentral, "it's time to shift our gears and get moving." He said some of what happened in the last legislative session was evidence that interest in hydro is growing.

Asked about overcoming opposition to dams, Carey said: "You'll never overcome opposition if you never start."

In the case of Watana on the Susitna, there are fewer fish issues because salmon don't return as far up the river as Watana.

Carter noted that even in the Lower 48 dams are still being built and the height of existing dams increased. While most of that is for water supply, there are hydropower components.

Wilson called opposition to dams "the big elephant in the room."

But no people would be displaced in these projects, he said, and the state's regulatory regime and environmental regulations "are second to none in the world" and impose a lot of restraints.

Wilson said the big issues are fish, siltation and downstream effects, "all of which can be mitigated and addressed." ●

Contact Kristen Nelson at knelson@petroleumnews.com

● ENVIRONMENT & SAFETY

Deadline set in polar bear listing case

Federal judge gives Interior Department until Dec. 23 to say why bears 'threatened' instead of 'endangered'; hearing set for Feb. 23

By DAN JOLING
The Associated Press

A federal judge has given the Interior Department a Dec. 23 deadline to explain why polar bears were listed in 2008 as a "threatened" species instead of the more-protective "endangered."

The written order issued Nov. 4 by Judge Emmet Sullivan of the U.S. District Court in Washington, D.C., follows an October hearing on multiple lawsuits challenging the "threatened" listing.

The polar bears' status has implications for issues ranging from national climate change legislation to Arctic offshore drilling and sport hunting.

The State of Alaska sued to overturn the listing, claiming it was not based on the best scientific evidence available.

Sullivan did not tell the U.S. Fish and Wildlife Service what the ultimate listing for polar bears should be, but he said the agency had inadequately explained its "threatened" listing.

"The federal defendants contend that, as a matter of law, an 'endangered species' must be in imminent danger of extinction," he wrote.

Sullivan said an "imminence" requirement was an erroneous conclusion.

Congress intentionally left the Endangered Species Act ambiguous, he wrote. The judge cited a previous case that concluded lawmakers need not supply regulators with a specific formula for their guidance where flexibility to respond to variable conditions constitutes the essence of the program.

Imminence could be one factor

Imminence of harm could be one factor the agency weighs, Sullivan said, but not necessarily a limiting factor. The agency has broad discretion, he said, to weigh other factors.

The law says a listing determination must be made on the basis of one or more of five factors, including current or threatened destruction of a species habitat or range.

Former Interior Secretary Dirk Kempthorne in May 2008 declared polar bears were threatened, or on the way to extinction, because of the rapid disappearance of the Arctic sea ice that they use for hunting, breeding and traveling. Scientists predict sea ice will continue to melt because of global warming.

Kempthorne stopped short of declaring polar bears endangered, a move that would increase protections for the bear.

Among the immediate effects of the listing was the Fish and Wildlife Service decision to stop issuing permits to import sport-hunted polar bear hides from other countries.

State, environmentalists sued

The State of Alaska sued to overturn the listing, claiming it was not based on the best scientific evidence available. State officials fear the listing will impede offshore petroleum drilling on the outer continental shelf of the Chukchi and Beaufort seas.

Environmental groups have also sued, saying an "endangered" listing is warranted.

Along with the listing, Kempthorne created a "special rule" stating that the Endangered Species Act would not be used to set climate policy or limit greenhouse gas emissions, which contribute to global warming and melting ice in the Arctic Ocean.

The Obama administration upheld the Bush-era policy, declaring that the endangered species law can't be used to regulate greenhouse gases emitted by sources outside of polar bears' habitat. If the bears are found to be endangered, however, that could open the door to using the Endangered Species Act to regulate greenhouse gases.

Kassie Siegel, an attorney for the Center for Biological Diversity who wrote the original petition for listing polar bears, said environmental groups were cheered by Sullivan's ruling. The judge correctly concluded that an imminent threat of extinction is not necessary for officials to declare polar bears endangered.

The decision opens the door for the Obama administration to break from a flawed decision by the Bush administration, she said, and give bears added protections.

"They can do the right thing now," she said. "We're going to be urging them to."

Sullivan set a hearing in the case for Feb. 23. ●

ENVIRONMENT & SAFETY

Wilderness League opens Fairbanks office

The Alaska Wilderness League has opened an office in Fairbanks to track issues on federal Bureau of Management Lands in the Interior.

The Washington, D.C.-based conservation group told the Fairbanks Daily News-Miner the office will work on securing wilderness designations in the National Petroleum Reserve-Alaska on the North Slope and on other BLM lands in the eastern Interior.

Thirty-seven-year-old Darcie Warden will serve as outreach coordinator in the one-person Fairbanks office.

BLM district manager Bob Schneider in Fairbanks said the agency welcomes input from the Alaska Wilderness League, just as it does from all public organizations.

The Alaska Wilderness League was formed in 1993 to protect Alaska's public lands from development. The League already had offices in Anchorage and Juneau.

—THE ASSOCIATED PRESS


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● PIPELINES & DOWNSTREAM

BP defends ‘F’ ratings on Alaska lines

By RACHEL D’ORO
The Associated Press

Internal “F” ratings of pipeline sections operated by BP PLC in Alaska’s North Slope show the company’s corrosion monitoring program is succeeding, not failing, a company spokesman said Nov. 4.

Spokesman Steve Rinehart was responding to a report by the independent investigative news organization ProPublica that said the rating means the pipeline walls are 80 percent corroded and could rupture.

That’s not always the case, Rinehart said. Pipes with less corrosion but in such sensitive areas as high-pressure lines could also get that rating, which doesn’t always mean the line is unsafe or facing imminent failure, he said.

“What it does mean is it prompts a higher priority repair plan,” Rinehart said. That could mean immediate repairs, taking a line out of service, or reducing pressure in the line pending a longer-term solution.

ProPublica says it obtained an internal BP maintenance report generated in early October that noted at least 148 pipelines received the most critical “F” rating. But Rinehart said as of Nov. 3, 151 locations — not entire pipes — had the rating among more than 1,600 miles of pipelines.

“Most of these are small areas that are identified through a big and continuing inspection program,” he said.

Two large spills in 2006

North Slope pipeline corrosion came under intense public scrutiny with two large oil spills in 2006. Both spills were traced to BP’s failure to regularly clean and inspect two of its pipelines over the course of several years. Rinehart said the spills reinforced the need to intensify the company’s corrosion efforts, which it began to do earlier in the decade.

BP ultimately agreed with federal prosecutors to pay $20 million in fines and restitution for the first spill, the largest ever on Prudhoe, the nation’s largest oil field. The spills also led BP to replace 16 miles of transit lines.

Critics used the events as examples of the oil industry’s failure to properly maintain the North Slope’s aging infrastructure. Among problems they list are pipelines dotted with inadequate patches and gas-leak warning systems they call obsolete.

Marc Kovac, a 33-year BP employee who works as a well-pad mechanic on the North Slope, said he is among several staffers who have gone to company managers with safety concerns including pipeline corrosion.

“Management didn’t care,” he said.

Kovac said BP takes too long to address “F”-rated pipelines. He believes the company should be more concerned about safety and less driven by cutting costs.

“Once a piece of pipe, or an area in a piece of pipe or vessel, has become ‘F’ ranked, it means that it’s in trouble,” he said.

Millions spent annually

BP says it spends millions annually on North Slope maintenance and upgrades. The current capital budget totals $850 million, according to Rinehart, who said he didn’t know how much was targeted for repairs and maintenance.

This year, the company conducted more than 150,000 exterior pipeline inspections, Rinehart said. BP also ran 77,000 internal inspections, using a variety of tools, including “smart pigs,” tools sent through pipelines to assess their condition, he said.

“We’ve got a very active and continuing corrosion-mitigation program,” Rinehart said. “And it’s been successful. By our markers, corrosion-related failures are coming down.” ●

E&P

US rig count up by 11 to 1,683

The number of rigs actively exploring for oil and natural gas in the U.S. increased by 11 the week ending Nov. 5 to 1,683.

Houston-based Baker Hughes Inc. said 955 rigs were exploring for natural gas and 718 for oil. Ten were listed as miscellaneous. A year ago this week, the rig count stood at 1,078.

Of the major oil- and gas-producing states, New Mexico gained six rigs, Texas gained four, Wyoming gained three, Alaska gained two and Arkansas, California and Louisiana each gained one. Oklahoma lost five rigs and Pennsylvania lost two. Colorado, North Dakota and West Virginia remained unchanged.

The rig count tally peaked at 4,530 in 1981, during the height of the oil boom. The industry posted a record low of 488 in 1999.

—THE ASSOCIATED PRESS

● NATURAL GAS

Mackenzie point-man steps down

By GARY PARK

For Petroleum News

A surprise departure from the Canadian government has created even more turmoil around the Mackenzie Gas Project.

On top of uncertainty over the regulatory and economic aspects of the C$16.2 billion project, the Canadian government's role in the project was turned on its head when Environment Minister Jim Prentice announced Nov. 4 that he was leaving politics for a job as vice chairman of the Canadian Imperial Bank of Commerce, one of Canada's top five banks.

Rated as Prime Minister Stephen Harper's most trusted lieutenant and once of the few in government to have the respect of the opposition parties, Prentice was head-hunted by the bank as he was closing in on his own self-imposed deadline of 10 years in politics. He held three posts during five years in cabinet, the last two in environment.

JIM PRENTICE

Whatever ambitions he might have had to succeed Harper as leader of the Conservative party were virtually ruled out by the fact that both men come from Calgary.

Sources say John Baird, leader of the government in the House of Commons, will be environment minister and have responsibility for the MGP on an interim basis.

Prentice says he's finished

Prentice is adamant he has finished with politics, saying he is "closing that chapter," despite speculation he is young enough at 54 to make a return.

His cabinet legacy included a reformed First Nations land claims process, a 30 percent increase in the land base for national parks, a timetable to phase out coal-fired power plants and a science-based investigation of the oil sands' impact on regional water supplies.

But his record was overshadowed by an international campaign against the oil sands and his own government's failure to impose a carbon tax or a cap-and-trade mechanism for greenhouse gas emissions, pending leadership action by the United States. That left Prentice to field ridicule at international climate-change conferences.

He also carried the cabinet file on the MGP, leaving no doubt that he was a strong backer of commercializing oil and natural gas in Canada's North.

But observers believe he was unable to gain cabinet support to spend federal money on MGP infrastructure or to sign off on a fiscal agreement for the project.

Sources say John Baird, leader of the government in the House of Commons, will be environment minister and have responsibility for the MGP on an interim basis. ●

Contact Gary Park through publisher@petroleumnews.com

● ENVIRONMENT & SAFETY

Experts: BP increased Gulf blowout risk

By DINA CAPPIELLO & SETH BORENSTEIN

Associated Press Writers

BP too often operated on the fly in the closing days of work on its doomed Gulf oil well, adding needless risk of a blowout, investigators, experts and panel members said at the presidential oil spill commission Nov. 9.

They said the company was hurried and made confusing, last-minute changes to plans that were unusual in the complex environment of deep water. They said BP could have operated more safely if the company took the time to get the necessary equipment and materials.

"We are aware of what appeared to be a rush to completion," commission Co-chairman William K. Reilly said. What is unclear, he said, is what drove people to determine they could not wait for equipment and materials to perform operations more safely.

Lawyers investigating the April 20 disaster have said they found no evidence that anyone aboard the rig or on shore made a conscious decision to sacrifice safety for money. But the panel's leaders made clear Nov. 9 that the findings in sum exposed a lack of safety culture on the rig, with Reilly blasting all three companies — BP, Halliburton Co., and Transocean — as "laggards" in the industry and in "need of top-to-bottom reform."

Well plugging a focus

Much of the scrutiny focused on the BP's plan to temporarily plug the well, which investigators with the presidential commission say added to the risk of a blowout. Plugging the well is a procedure used to seal it off until the company comes back to produce oil and gas. BP says its actions are common throughout the industry, but numerous experts suggested otherwise Nov. 9.

Several questioned BP's use of a single plug in the process. Charlie Williams, a chief scientist with Shell Energy Resources Inc., said the company used a minimum of three plugs in its deepwater wells.

BP also chose to fill the well with seawater, rather than heavy drilling mud, leaving it vulnerable to an upsurge of oil and gas — a condition that is not allowed for exploratory wells drilled in other places, experts said. The company also chose not to use mechanical plugs, devices put inside the pipe that also can block oil and gas.

Many of the decisions would have required additional time and materials, said Steve Lewis, an advanced drilling technology engineer with Seldovia Marine Services who reviewed BP's drilling plans, federal permits and communications on behalf of the commission.

"I know there was pressure on these people to get done and move on," Lewis said. "The apparent shuffling and scrambling was not really necessary."

BP in charge

Experts also said BP was in charge of making the critical decisions aboard the rig, such as signing off on a critical pressure test that both BP and others acknowledge was misinterpreted.

Meanwhile, in New Orleans, a federal judge on Nov. 9 barred news organizations from a conference over a company's claim that the government is moving too slowly to resume offshore drilling. Ensco Offshore claims that since the ban was lifted Oct. 12, the government has not issued a single permit that would allow the resumption of any previously suspended drilling activities.

The government doesn't seem to dispute that allegation, saying in a Nov. 8 filing that it must ensure applications meet regulations toughened after the Gulf of Mexico oil spill.

The moratorium was ordered in the wake of the April 20 explosion on the BP-leased Deepwater Horizon rig. ●

continued from page 7

DONKEL

of Oil and Gas from 2000-05, provided geologic information on tracts which Donkel acquired in the October sales. In an e-mail to Petroleum News he called the acreage "an impressive collection of moderate to high potential tracts."

Brizzolara said Donkel's strategy was "to stay close to the Barrow Arch and the known producing fields and to target a wide range of play concepts."

The three leases Donkel acquired north of the Arctic National Wildlife Refuge "have expanded to the southeast Donkel/Cade holdings within the accumulation defined by the ARCO Stinson #1 well," Brizzolara said, a well which "discovered flowable gas and oil in both the basement and in a shallower Tertiary horizon," horizons which are believed to "expand and thicken to the southeast."

Brizzolara said the other Beaufort Sea tracts (six off Badami and four off Liberty) "hold potential in multiple horizons," along the Barrow Arch, "a regional structural feature along which many of the North Slopes oil fields are localized." The specific interest is Kekiktuk and shallower deepwater Paleocene sands. "In other words, a continuation of the Liberty and Badami trends," he said.

In the North Slope sale area, leases which Donkel acquired south of Point Thomson "remain focused on Paleocene stratigraphic traps akin to the accumulations at Yukon Gold and Sourdough. Brizzolara said that in this setting "if a deepwater Tertiary sand with good reservoir quality and stratigraphic trapping configuration is encountered it most likely will be oil and/or gas charged."

Donkel took a block of 12 leases south of Prudhoe Bay where Brizzolara said the focus is on a multiplay concept, with the Ivishak formation a primary target.

"Although south of the main Prudhoe oil/water contact, numerous isolated fault blocks are apparent on seismic data. It is highly conceivable that some of these upthrown fault blocks have successfully trapped hydrocarbons," Brizzolara said, while downthrown blocks may hold thin Kuparuk C-sand equivalents.

He also said the area has the potential for production from West Sak sands.

see **DONKEL** *page 19*

continued from page 1

ARMSTRONG

North Slope.

Hewitt Mineral Corp. surrendered its remaining North Aleutian basin leases in October.

The Oklahoma independent relinquished four leases covering some 22,682 acres in the North Aleutian basin, also known as the Bristol Bay basin, around the Alaska Peninsula.

Hewitt picked up the leases in the same October 2005 sale where Shell Offshore acquired some 190,000 acres. Hewitt also acquired a lease in 2007 that it previously dropped.

The four Hewitt leases were on the southwest side of Herendeen Bay.

Following some geologic studies, Hewitt believed it found a new natural gas play under its leases. "We now have identified some evidence that there could be a significant carbonate reservoir under the Peninsula that has not been recognized," Bryan Sralla, a petroleum geologist for the company, told Petroleum News in February 2007.

Hewitt believed a 14,000 to 15,000-foot well could test all the stratigraphy with exploration potential in the geologic structure, but ultimately the company never drilled.

With the latest news, there are now no active leases in the North Aleutian basin.

Shell relinquished all 33 of its state leases in the basin in late 2008, saying the onshore and inland areas of the Bristol Bay region no longer fitted into the company's exploration plans. State Alaska Peninsula lease sales in 2008, 2009 and 2010 drew no bidders.

Following the May 2010 lease sale, Division of Oil and Gas Director Kevin Banks connected the lack of bids to the federal government's decision to take the North Aleutian basin off its sale schedule, but added that the State of Alaska would continue to offer Alaska Peninsula acreage for leasing each year under the areawide leasing program as a way to remain current and to be ready in case the conditions someday favored leasing again.

Storm Cat and Unocal drops

In other leasing news, the state terminated three Storm Cat Energy leases covering some 12,543 onshore Cook Inlet acres in the area north of Knik Arm for failure to pay rentals.

Storm Cat drilled its only Alaska well, called Northern Dancer No. 1, in that area in early 2006, but the recently terminated leases do not include the Northern Dancer well site.

Storm Cat holds both State of Alaska and Alaska Mental Health Land Trust leases.

As of Nov. 7 the termination had not been recorded in state lease files.

Finally, Union Oil Co. of California, an affiliate of Chevron, allowed two leases covering some 11,426 acres in the southern Kenai Peninsula to expire. Unocal picked up the leases for $60,652.80 in a May 2003 sale. One sat adjacent to the eastern boundary of Unocal's Nikolaevsk unit, while the other was very far to the east of Unocal's Ninilchik unit.

Chevron recently announced plans to market all of its Cook Inlet assets.

NOTE: A copyrighted oil and gas lease map from Mapmakers Alaska (www.mapmakersalaska.com/) was a research tool used in preparing this story.

—ERIC LIDJI

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DONKEL

What's next?

Brizzolara said acquisition of high-quality seismic data will be essential to defining the potential of these trends.

"Mr. Donkel's team of geoscientists is currently evaluating all available data in an effort to define specific high potential leads and prospects," he said.

Gross said the best opportunities for the lease sale "lay in building upon Dan's already extensive leasehold, which we have continued to study in light of new information regarding the geology of the areas. The advances in drilling and production technology have also created new hydrocarbon prospects that are now economic in these areas." ●

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ENVIRONMENT & SAFETY

RDC, state of Alaska hosting ESA primer

The Resource Development Council and the State of Alaska will host an Endangered Species Act primer Nov. 16 from 1-5 p.m. at the Dena'ina Center.

Alaska Attorney General Dan Sullivan and former Gov. Bill Sheffield are among the speakers.

The event is free to the public, but RSVPs are requested to resources@akrdc.org to ensure that enough materials and seating are provided.

—PETROLEUM NEWS

CIRI says rising gas prices will justify Fire Island wind farm

During a Nov. 8 talk to the Anchorage Chamber of Commerce Make it Monday Forum about Cook Inlet Region Inc's Fire Island wind farm project, Suzanne Gibson, CIRI's senior director for energy development, said that although the projected price of power from the wind farm exceeds the current price of electricity in Southcentral Alaska, the rising price of natural gas in Southcentral will before long make power from the region's predominantly gas-fired power stations more expensive than wind power.

The Southcentral gas and power utilities anticipate having to import liquefied natural gas at some time in the next few years, to cover an anticipated shortfall in locally produced gas, Gibson said. But the current LNG price in Japan, the world's largest LNG importer, is $13 per million Btu, she said. And a recent study commissioned by the utilities has indicated that, as an alternative to LNG imports, the drilling of sufficient gas wells to maintain local gas supplies would cost something in excess of $2 billion, a cost that would surely push up gas prices.

A new gas supply agreement, signed earlier this year between Southcentral power utility Chugach Electric Association and Cook Inlet gas producer Marathon Oil Co., has gas prices set in an inflation-indexed range from $5.90 to $8.90 per million Btu. Southcentral Alaska utility gas consumers currently pay around $7 per million Btu for gas, plus utility gas distribution and service fees.

—ALAN BAILEY

continued from page 3

WIND FARM

communications, told Petroleum News Nov. 9 that Chugach is still engaged in confidential negotiations with CIRI; that integration of the Fire Island power station into the Southcentral grid is a serious concern; and that work is under way to determine the methods and costs of integration.

Price of power

Another key issue in negotiations between CIRI and the Alaska Railbelt utilities is the likely price of Fire Island-generated power, a price that CIRI has estimated at around 9.5 cents per kilowatt hour, excluding the integration costs. The fact that the projected wind power price is higher than the current Southcentral Alaska cost of electricity is proving a stumbling block in negotiations, Zentz said. But these pricing concerns ignore the fact that people expect the price of the natural gas used for much Southcentral power generation to increase sharply over the next few years, as Cook Inlet gas supplies continue to run down, he said.

Zentz also said that a possible U.S. Department of Energy loan guarantee could reduce the price of Fire Island power to between 8 and 8.5 cents per kilowatt hour.

In contract negotiations, Chugach and CIRI are still 20 percent apart on price; Anchorage utility, Municipal Light & Power, has not responded to offers from CIRI; discussions are still in progress with Matanuska Electric Association; discussions are also in progress with Fairbanks-based Golden Valley Electric Association; and Homer Electric has refused to consider buying any Fire Island power, Zentz said.

Critical timing

But, while negotiations continue, time is of the essence in signing power purchase agreements — CIRI needs to secure bonding for the project by April 2011 to bring the wind farm on line in 2012. Without purchase agreements the bonding will not happen.

Completion of the project in 2012 is essential in securing a federal renewable energy grant of $43.9 million, to cover part of the $162 million Fire Island project cost — CIRI started construction of the wind farm in 2010 as one of the other perquisites for that grant.

Without the federal grant, the cost of power from Fire Island could be 10 to 20 percent higher, depending on what other federal incentives would be available, Zentz told the Anchorage Chamber of Commerce on Nov. 8.

Reduced cost

CIRI says that it is particularly upset about criticisms over the cost of Fire Island power because the corporation has been able to reduce the original cost estimate of nearly $200 million for the project to $162 million, by optimizing the way in which the project is being carried out and by taking advantage of cost reductions in the wake of the recent economic recession. The cost savings will be passed onto customers, rather than be used to improve CIRI's financial return from the wind farm, Zentz told the Energy Task Force.

In the wake of the CIRI presentation, the Energy Task Force formed a committee of three to investigate the Fire Island wind farm situation, to enable the task force to make recommendations to Anchorage Mayor Dan Sullivan on any actions that it might be appropriate for the mayor to take.

"This is a project … that has a state of immediacy. It's got to move and things have to be done now," said Energy Task Force Chairman Dan Coffey. ●

Contact Alan Bailey at abailey@petroleumnews.com

Petroleum news

Oil Patch Bits

Air Liquide to participate in power plant storage

Air Liquide Process & Construction Inc., part of the Air Liquide Engineering & Construction organization, said Oct. 7 that it has been named by the U.S. Department of Energy to participate in the development of FutureGen 2.0 — the world's first full scale oxy-combustion power plant incorporating carbon capture and storage.

The recent agreement between DOE and Ameren Energy Resources Co. LLC is part of a commitment by DOE to award $1 billion to the U.S. federal funding for the clean coal power project, which includes sub-awards to Air Liquide and its technology partner Babcock & Wilcox Power Generation Group Inc.

Carbon capture and storage is critical to reducing greenhouse gas emissions from power plants and making clean energy a reality. This project represents the first full-scale production initiative for clean coal energy using oxy-combustion technology and CCS. The project is designed to capture and store approximately 1.3 million tons of carbon each year, 90 percent of the plants carbon emissions.

Air Liquide, the world leader in gases for industry, health and environment and has been investing in oxy-combustion technology for more than a decade.

ASRC leads Chambers of Commerce top 49ers list

Arctic Slope Regional Corp. said it is proud to once again be recognized by the Alaska State Chamber of Commerce, Alaska Business Monthly and other business leaders as the top Alaska-owned and operated company. This is the 16th consecutive year that ASRC has been No. 1 on the "Top 49ers" list, based on the prior year's gross revenue.

"Our continued financial stability is a direct result of our diversity, and the dedication of ASRC's employees," said Rex Allen Rock Sr., president and CEO of Arctic Slope Regional Corp. "I'm most proud that these revenue numbers allow us to better the lives of our approximately 11,000 shareholders, both directly in terms of dividends, but also indirectly — in the way of investments in community projects and educational opportunities. I congratulate the many other successful businesses on the list as well."

In 2009, ASRC's revenues came in at $1.95 billion; its principal activities include energy services, petroleum refining and marketing, engineering and construction, government services, resources development, commercial lending and tourism.

WesternGeco acquiring dual coil shooting survey

WesternGeco, a business segment of Schlumberger, said Oct. 14 that it has begun the acquisition of the Revolution multiclient survey. Revolution marks the first time that Dual Coil Shooting multivessel full-azimuth acquisition has been performed commercially in the industry worldwide.

see **OIL PATCH BITS** *page 25*

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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INSIDER

contractor staffing on the North Slope typically shrinks seasonally in the fall, and this year is no exception. We typically increase contractor staffing for key activities, such as summer plant turn-around maintenance or winter construction. The reduction in North Slope contractor jobs this fall is mainly the result of the end of the summer peak activity season. My best estimate is that this seasonal contractor reduction affected about 110 individuals."

In addition to the seasonal contraction, Rinehart said, "We have recently changed the way we schedule and conduct some well work. As a result, we need fewer slickline crews, resulting in an estimated reduction of about 30 contractor jobs."

For information about BP's capital budget for Alaska in 2011, see the last section in the aforementioned page 1 BP sale article.

—KAY CASHMAN

Alaska pipeline owners might be pulling for judge's promotion

IN THE OCT. 31 ISSUE of Petroleum News, we told you about the efforts of the trans-Alaska pipeline owners to replace state Superior Court Judge Sharon Gleason with someone more to their liking.

Gleason is presiding over a high-stakes legal battle concerning the level of property taxes due on the 800-mile pipeline system. In May, after a trial, she put the system's assessed value at $9.98 billion, way more than the $850 million the owners argued. Gleason's ruling could mean the owners will have to pony up an extra $113 million in state and municipal property taxes for 2006 alone.

Our story detailed how the pipeline owners — BP, ExxonMobil, ConocoPhillips, Chevron and Koch Industries — are trying to exercise their right under court rules to have another judge assigned to the case.

Well, here's an interesting angle we failed to mention. It seems the owners might soon be rid of Gleason for another reason entirely.

The presiding judge of the Superior Court in Anchorage, Gleason appears to be a leading candidate to succeed U.S. District Court Judge John W. Sedwick, who is moving to senior status on March 13, 2011.

Among the 19 people who have applied for presidential appointment to the federal judgeship, Gleason ranked third highest in an Alaska Bar Association poll, the Anchorage Daily News reported Oct. 12. Alaska Sens. Mark Begich and Lisa Murkowski will use the poll results to help craft a list of recommendations to send to the White House.

In light of Gleason's career prospects, it's interesting to note that the pipeline owners, in an Oct. 19 filing in the tax case, suggest the planned trial of their consolidated 2007, 2008 and 2009 tax appeals be put off a year. Lawyers for the owners complain they don't have adequate time to prepare for the trial, set to start in the fall of 2011.

The owners previously had asked that the trial be deferred until after the Alaska Supreme Court reviews Gleason's 2006 tax ruling.

But Gleason shot that down.

—WESLEY LOY

Report: White House altered safety report

THE INTERIOR DEPARTMENT'S INSPECTOR general says the White House edited a drilling safety report in a way that made it falsely appear that scientists and experts supported the idea of the administration's six-month ban on new drilling.

The inspector general says the editing changes resulted "in the implication that the moratorium recommendation had been peer reviewed." But it hadn't been. The scientists were only asked to review new safety measures for offshore drilling.

"There was no intent to mislead the public," said Kendra Barkoff, a spokeswoman for Interior Secretary Ken Salazar, who also recommended in the May 27 safety report that a moratorium be placed on deepwater oil and gas exploration. "The decision to impose a temporary moratorium on deepwater drilling was made by the secretary, following consultation with colleagues including the White House."

The Interior Department, after one of the reviewers complained about the inference, promptly issued an apology to the reviewers during a conference call, with a letter and personal meeting in June.

The inspector general's report, which was originally requested by Louisiana Sen. David Vitter and Rep. Steve Scalise in June, said the administration did not violate federal rules because the executive summary did not say the experts approved the recommendations and the department offered a formal apology and had publicly clarified the nature of the expert review.

But Louisiana Rep. Bill Cassidy, a Republican, said in a statement that the investigation proved "that the blanket drilling moratorium was driven by a politics and not by science."

"Candidate Obama promised that he would be guided by science, not ideology," Cassidy said. Cassidy said if that were true thousands of jobs and billions in economic activity would have been preserved on the Gulf coast.

The website Politico was first to report the inspector general's findings. The Associated Press on Nov. 10 obtained a copy of the report, which has not been publicly released.

—THE ASSOCIATED PRESS

continued from page 1

JACK-UP RIG

units.

Buccaneer said it has identified a jack-up rig "suitable" for the Cook Inlet, completed an inspection of the rig in Singapore and indentified additional upgrades. Buccaneer also said that Kenai Offshore Ventures and the operating company are currently in talks with Seahawk Drilling Inc., a Houston-based offshore driller, to physically operate the rig.

Under a proposed timeline, Buccaneer wants to have the rig in Alaska by May 2011.

A jack-up is a mobile drilling unit well suited for relatively shallow offshore areas. In the absence of an offshore platform, it is crucial for exploration in an area like the Cook Inlet.

Financing through AIDEA

Buccaneer's proposed financing for the project is also a new approach.

On Nov. 8, Kenai Offshore Ventures LLC applied for $60 million in Recovery Zone Facility Bonds from the Alaska Industrial Development and Export Authority.

Recovery Zone Facility Bonds, or RZFBs, are a tax-exempt bond included in the American Recovery and Reinvestment Act of 2009, also known as the stimulus package.

The bonds gave local municipalities, particularly those in economic distress, a way to offer tax-exempt funding to businesses looking to invest within the community. Because some of the most economically distressed areas in Alaska are not within a recognized municipality, though, the state charged AIDEA with allocating and issuing the bonds.

On the Web

See previous Petroleum News coverage:

"Jack-up for Buccaneer? Will ask AIDEA's help to bring rig north," in Oct. 24, 2010, issue at www.petroleumnews.com/pnads/970144450.shtml

The bond is essentially a roundabout loan, placing AIDEA and its bonding authority in between a private lender and borrower as a way to provide tax-exempt financing.

Loans secured against rig

Buccaneer said it has identified a lending institution to underwrite the bonds, that "loans will be secured against the rig" and that Kenai Offshore Venture "will raise the remaining capital in the form of preferred and common equity."

AIDEA received two applications for Recovery Zone Facility Bonds by the deadline on Nov. 8. In addition to the application from Kenai Offshore Ventures, AIDEA received an application for a company looking to put together a retail project. Around $105 million in bonding remains unallocated, enough so that the two projects are not in competition.

AIDEA will decide on Nov. 15 whether to award the RZFBs to the applicants.

On Nov. 22, the AIDEA board will consider a resolution that would allow those bonds to retroactively reimburse expenses made on each project in the previous 60 days.

Alaska originally received the authority to issue $135 million in RZFB by Jan. 1, 2011.

The city of Kenai and the Kenai Peninsula Borough both passed resolutions in recent weeks that support using RZFB as a way for a company to acquire a jack-up rig. Both resolutions note that "Buccaneer Alaska, and possibly other companies, are submitting a proposal to AIDEA for funds to acquire a jack-up drill rig to bring to the Cook Inlet."

That support is technical necessary because AIDEA does not issue bonds larger than $6 million without proof of support from the community where the money would be spent.

Possibility for partners

Kenai Offshore Venture's claim to have found five years of work for a rig has merit.

Escopeta Oil has been trying to bring a jack-up rig to Alaska for nearly a decade, even going so far as to get all the major pieces of a drilling program in place back in 2006 before losing a partner on the project. Escopeta currently owns and operates the Kitchen Lights unit, a large offshore unit in an underexplored part of the upper Cook Inlet.

Those efforts are currently in limbo, though. In July, the Department of Natural Resources put the unit into default and in September Escopeta appealed that ruling. The company, though, remains optimistic that it can eventually bring a jack-up to Alaska.

(NOTE: See story this issue about Escopeta)

Other companies with offshore acreage in Cook Inlet include newcomer independent Cook Inlet Energy, majors like ConocoPhillips, Marathon and Chevron (which recently announced plans to sell its Cook Inlet assets) and large independents Apache (which acquired onshore and offshore acreage in Cook Inlet this summer) and Pioneer Natural Resources, which plans to drill its offshore acreage from an onshore pad.

While the quest to bring a jack-up rig to Alaska is not new, it got new momentum earlier this year with the creation of new tax credits. Under Senate Bill 309, the state will pay 100 percent, up to $25 million, of the first offshore well drilled to "the pre-Tertiary zone" in the Cook Inlet basin using a jack-up rig. The state will also pay 90 percent, up to $22.5 million, of the second well, and 80 percent, up to $20 million, of the third well. The wells must be drilled by different companies but all three wells must be drilled using the same rig, a provision that could encourage coordination among the various Cook Inlet leaseholders looking to explore different offshore targets.

The companies must repay 50 percent of the credit if a well produces.

Buccaneer said that even though their second well wouldn't be covered by SB 309, it would get 65 percent credit under ACES. ●

NOTE: An article in the Oct. 24, 2010 issue of Petroleum News titled "Jack-up for Buccaneer? Will ask AIDEA's help to bring rig north," speculated on the possibility of an "unexpected funding cycle," where a company received a loan from the State and the State in turn repaid that loan through the new tax credit program. That scenario is not entirely accurate, though, because AIDEA would be issuing a bond, not a loan.

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BP SALE

TNK-BP is considering opportunities for buying assets which could support TNK-BP's strategic growth opportunities and added value creation for the company. Any further comments would be premature at this stage."

So, maybe? BP certainly has political strength in Alaska. Both companies have business strength. TNK-BP, which makes up more than a quarter of BP's reserves, placed 17 in Platts Top 250 Global Energy Company Rankings for 2009, a designation that recognizes outstanding financial performance based on asset worth, revenues, profits and return on investment.

A good match for Alaska

At a glance TNK-BP, which in mid-October purchased BP fields in Vietnam and Venezuela for $1.9 billion, appears to be a good match for Alaska.

For one, the company wants to transform from a major oil group to a major oil *and* gas group. Alaska has world-class reserves of natural gas.

For another, a significant part of TNK-BP's crude is now produced from fields which were long considered either uneconomic or unrecoverable, including heavy oil accumulations. Since its formation in September 2003, TNK-BP has established a track record of successfully applying technology to develop hard-to-recover and mature reserves.

BPXA has upwards of 20 billion untapped barrels of heavy oil close to infrastructure in northern Alaska and the largest Alaska fields it has an interest in all can be classified as mature.

Plus, TNK-BP spends a lot of money on mature fields, heavy oil development and exploration for new accumulations, something the State of Alaska would welcome.

Finally, the Russian oil giant has already been working with BP in Alaska for several years, sending employees to the state to study the techniques BP and ConocoPhillips are using and developing to extract heavy oil and to increase production at mature fields such as Prudhoe and Kuparuk.

Remember Francis Sommer?

TNK-BP's top technology executive is none other than Francis Sommer, who began his career with BP in 1986 working at the Prudhoe Bay oil field. Sommer held several engineering positions in Alaska, specializing in new field appraisal and development, enhanced oil recovery, reservoir modeling and performance forecasting.

Sommer left Alaska in 1992 for three years, returning to lead subsurface teams at the Point Thomson and Northstar fields.

In 2003, he became asset manager for Prudhoe Bay. In this role, according to TNK-BP's bio on Sommer, he "led efforts in novel technology applications such as gas cap water injection, LoSal water injection and viscous oil developments."

In late 2005 Sommer joined TNK-BP as vice president of production technology. Today he is executive vice president of technology.

Aside from all the rumors of a sale….

Aside from rumors of a possible sale of Alaska assets, putting BP's share of Prudhoe supposedly on the market for $5-$7 billion (not verified), BP has recently done things that gives those rumors credence.

The company is cutting specific costs that would allow it to squeeze more cash out of a sale. The latest example occurred in early November, when BP handed approximately 30 former ARCO Alaska employees, who work for BP in the Greater Prudhoe Bay Area, retirement packages

see **BP SALE** *page 27*

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OIL PATCH BITS

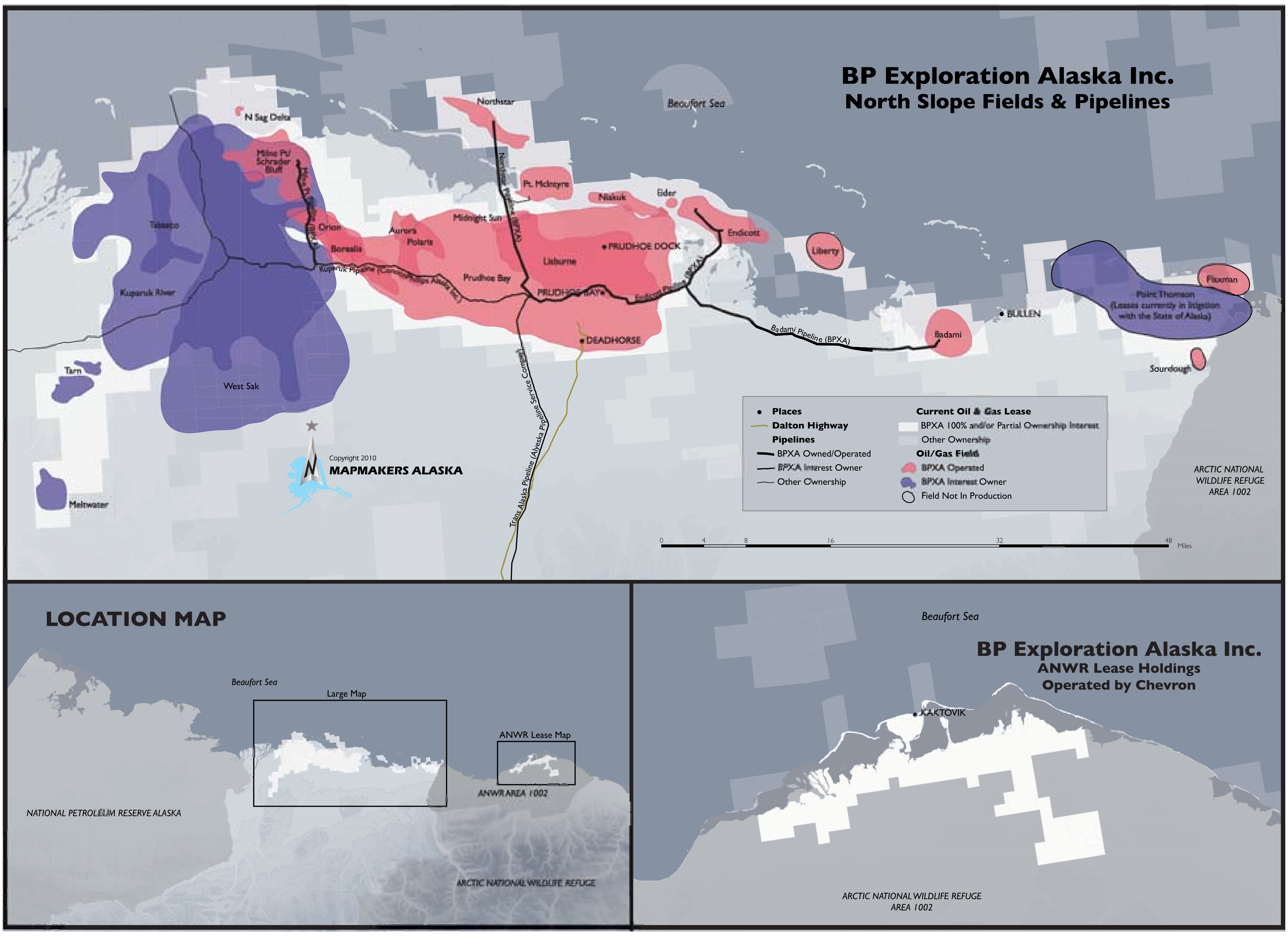
Located in the East Breaks and Garden Banks areas of the Western Gulf of Mexico, the Revolution multiclient survey will provide full-azimuth coverage for more than 130 outer continental shelf blocks.

"We are encouraged by the initial images derived from Revolution, our first Dual Coil survey. The ultra long offsets combined with full-azimuth illumination enables significant imaging uplift in the Gulf of Mexico's complex subsalt structures," said Thomas Scoulios, North America region manager, WesternGeco. "We are pleased with the commitments from multiple underwriters who are helping to direct this project's success."

Building on multi- and wide-azimuth techniques, the FAZ Dual Coil Shooting is a new, advanced method of acquiring ultra long offset marine seismic data using four vessels following a circular path. This acquisition provides better target illumination in challenging environments by enabling greater azimuthal coverage and a higher signal-to-noise ratio. Dual Coil Shooting technology is possible due to the capabilities of the Q-Marine point-receiver seismic system.

WesternGeco will apply the latest seismic data processing techniques to this survey, including true-azimuth 3-D Generalized Surface Multiple Prediction and anisotropic reverse time migration.

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.



BP Exploration Alaska Inc.
North Slope Fields & Pipelines
Beaufort Sea
N Sag Delta
Northstar
Milne Pt/ Schrader Bluff
Pt. McIntyre
Niakuk
Eider
Tabasco
Orion
Borealis
Aurora
Polaris
Midnight Sun
PRUDHOE DOCK
Endicott
Liberty
Kuparuk River
Lisburne
Prudhoe Bay
PRUDHOE BAY
DEADHORSE
Badami Pipeline (BPXA)
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ANWR AREA 1002
NATIONAL PETROLEUM RESERVE ALASKA
ARCTIC NATIONAL WILDLIFE REFUGE
Beaufort Sea
BP Exploration Alaska Inc.
ANWR Lease Holdings
Operated by Chevron
KAKTOVIK
ARCTIC NATIONAL WILDLIFE REFUGE
AREA 1002

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BP SALE

that give them a limited number of days to accept or lose the retirement provisos that former ARCO President Mike Bowlin negotiated for them before BP took over full operatorship of Prudhoe in 2000.

Prior to that time, ARCO Alaska operated half the field and BP operated the other. In the assumption of sole operatorship, BP retained some of ARCO Alaska's Prudhoe employees.

ARCO's retirement package was considered the Cadillac of the industry and, as such, the terms were very costly for BP to fulfill. According to PN sources close to the divesture of ARCO Alaska to Phillips Petroleum in 2000, BP's top executive, John Browne, agreed to honor the ARCO package for people who retired within 20 years. But BP had the option to renege on the agreement, providing, among other things, that BP gave written notice to all affected former ARCO employees, offering them a last chance at the munificent retirement plan terms.

This information came from three solid PN sources, including one of the 30 people who received a package. In response to a request for confirmation of the 30 or so former ARCO employees receiving packages, BP's Alaska spokesman Steve Rinehart told PN, "Persons retiring would need to speak for themselves about their financial arrangements."

Another recent action by BP was an initiative it presented at a town hall-style meeting several weeks ago in which the company asked employees and contractors to work as a team to cut "incidents" by 50 percent and make sure that BPXA was profitable at $50 per barrel oil.

How much cash does BP need?

To cover liabilities stemming from the Macondo well blowout and oil spill in the Gulf of Mexico, BP said in July it would raise between $25 billion and $30 billion over 18 months from selling oil and gas assets outside its key growth regions.

The Sunday Times reported in September, and BP later confirmed, that the company had increased its cash target for covering the Gulf disaster to $40 billion, up from BP's previously stated $30 billion maximum goal.

As of the end of October BP had raised more than $12 billion from asset sales.

The company's market value has fallen by more than a third since April 20, the day of the Gulf blowout.

But all is not gloom and doom. BP had a profitable third quarter — $1.79 billion in net income as compared to a $17.2 billion loss in the second quarter.

Three challenges in selling Prudhoe interest

BP has three challenges in selling its interest in Prudhoe, its most valuable asset in Alaska.

• One, if its sells its interest in the field without selling its shares in the subsidiary that holds its Prudhoe interest (BPXA), it has to contend with the preferential rights of at least its two major partners in the field, ExxonMobil and ConocoPhillips.

Those companies could make a sale and the transference of operatorship to a new working interest owner difficult. Exxon showed its willingness to do exactly that in 2000 when it filed a lawsuit to block the purchase of ARCO's Alaska assets by Phillips Petroleum, predecessor to ConocoPhillips, contending that it had contractual rights to first refusal on some of the assets and concerns over operatorship.

• Two, BP has committed a 16.4 percent royalty to the BP Prudhoe Bay Royalty Trust on essentially the first 90,000 barrels of daily net production of crude and condensate from the working interest of BPXA over the life of the Prudhoe Bay field, which would be a definite detriment to a potential buyer.

In its 2009 annual report to the U.S. Securities and Exchange Commission, BP said its net share of production from Prudhoe Bay was 69,000 barrels per day in 2009.

• Three, since its North Slope gas reserves, the bulk of which are at Prudhoe Bay, are stranded — unmarketable without a pipeline — it will be tough to set a value on BP's share of the gas for a purchase.

None of these challenges make a sale of individual BP oil and gas properties in the state — or a sale of BPXA and BP's pipeline subsidiaries — impossible. It just makes things more complicated, especially for Prudhoe Bay.

Or maybe BP is cutting Alaska spending?

Of course, another explanation for BP's actions is that it could be cutting discretionary spending in Alaska in 2011, a "classic BP" move when oil prices are down or, per the current situation, the UK-based company needs cash.

In support of this notion is the fact that local BP officials have been warning oil field partners not to count on BP investment in a number of Alaska projects, even those with a relatively short payback, such as seismic and drilling. None of PN's sources, however, have said funding has definitely been nixed and indications are the partners will pick up what BP is not willing to invest.

BP's 2011 Alaska capital budget has not yet been set, but in a Nov. 2 press release from BP's UK headquarters the company said, "Given the strength of our underlying cash flows and the investment opportunities available to us, our 2011 capital expenditure is currently under review and is expected to exceed the $18 billion previously indicated," which is more than the company allocated for 2009 or 2010 capital spending. ●

Note: See the copyrighted oil and gas lease map on page 26 from Mapmakers Alaska that shows BP's operated and non-operated oil and gas properties in Alaska.

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SPILL FINE

against BP's local subsidiary, BP Exploration (Alaska) Inc., in connection with the crude spill discovered on March 2, 2006.

The oil had leaked slowly over the course of perhaps five days from an almond-sized hole in an oil transit pipeline near Gathering Center 2 in the western operating area of the vast, BP-operated Prudhoe Bay oil field. The oil leaked onto the snow-covered tundra and a frozen lake.

Another, smaller leak occurred later in 2006 on the eastern side of Prudhoe Bay, forcing a partial shutdown of the field due to corrosion concerns with the transit lines, which fed sales-grade crude into the trans-Alaska pipeline.

BP would draw regulatory and congressional criticism for its poor maintenance of the lines, and ultimately the Alaska subsidiary pled guilty to a federal pollution misdemeanor. A judge sentenced the company to three years on probation and imposed $20 million in penalties.

That wrapped up criminal prosecution of BP Alaska for both the federal government and the state.

But each government on March 31, 2009, filed a civil suit against the company.

The state case is believed to pose the biggest threat to BP, as the state is seeking not only the statutory penalty for the spilled oil but also compensatory and punitive damages plus back taxes and royalties. State lawyers contend that BP's negligence led to emergency field shut-ins and pipeline replacements, costing the state revenue on an estimated production shortfall of 35 million barrels of crude oil and natural gas liquids.

The state's damages could exceed $1 billion, a state lawyer has said.

BP acknowledged liability

While BP Alaska is vigorously fighting most of the claims in the state's civil suit, its lawyers in the past have conceded the company can be fined for the spilled oil.

In court papers BP filed on May 26, 2009, company lawyers wrote: "BPXA acknowledges it is liable to the State under Alaska's strict liability statute for a civil penalty of approximately $1.7 million in connection with the March 2006 discharge."

Whether the company still feels this way might now be in question, given the tenor of the state's nine-page Nov. 8 motion seeking to compel BP to pay the penalty. The motion pertains only to the spill penalty, not the state's claims for compensatory and punitive damages or lost revenue.

BP has admitted negligence on its pipeline maintenance, has admitted that the size of the spill was 212,252 gallons, and has acknowledged liability for the penalty under the statute, the state argues.

"BPXA should be held to its concession" and pay the base civil penalty of $1,698,016, the state's motion says.

The company had not yet filed an answer to the state's motion as Petroleum News went to press.

BP ultimately could be forced to pay a much larger fine for the spilled oil. In addition to the base penalty, the state is suing for an "enhanced penalty" of four times the base penalty as provided for under statute AS 46.03.759. That's because BP violated its oil spill prevention and contingency plan and committed "gross negligence," the state says.

The enhanced penalty would tally almost $6.8 million. But the state isn't attempting to collect the enhanced penalty with its Nov. 8 motion, only the base penalty.

The motion notes: "AS 46.03.759 was enacted in 1989 immediately after the catastrophic crude oil spill in Prince William Sound from the oil tanker Exxon Valdez. The Alaska Legislature sought to increase penalties for the discharge of crude oil in amounts exceeding 18,000 gallons in order to create a greater economic incentive for safe operations by crude oil operators." ●

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