Petroleum news

page 3 9th Circuit upholds Shell's EPA air permits for Noble Discoverer

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NATURAL GAS

Chevron raises hopes

As incoming Kitimat operator, has global LNG experience; Encana, EOG out

By GARY PARK
For Petroleum News

Chevron has made one of the boldest moves yet to turn Canada's LNG export hopes into reality by taking over control of the Kitimat LNG project that has been stonewalled by its inability to secure long-term buyer contracts.

In a radical overhaul of Canada's most advanced LNG venture, Chevron will buy out the minority positions of Encana and EOG Resources, each of which held 30 percent stakes, while former operator Apache will raise its stake to 50 percent from 40 percent.

Chevron Canada spokesman Leif Sollid told Petroleum News that the transaction is "very exciting news" for his company, putting Kitimat in the forefront of North American plans to access Asian markets with its vast stores of shale gas.

Chevron Canada spokesman Leif Sollid told Petroleum News that the transaction is "very exciting news" for his company, putting Kitimat in the forefront of North American plans to access Asian markets with its vast stores of shale gas.

But the immediate focus "is on working through the transition period with Apache and taking operatorship within 90 days," he said.

see **CHEVRON CONTROL** *page 15*

FINANCE & ECONOMY

Archer fires back

Archer claims it fired Buccaneer over jack-up rig, not the other way around

By ERIC LIDJI
For Petroleum News

The international drilling giant Archer Drilling LLC is seeking more than $6 million in damages from Buccaneer Energy Ltd. for a breach of contract connected with maintenance work on the Endeavour jack-up drilling rig currently docked in Homer.

Coming as Buccaneer publicly announced that it had terminated the contract with Archer over late payments and "nonperformance," Archer filed a suit claiming the opposite: that it had terminated the contract because Buccaneer — and its affiliates and subsidiaries, including Kenai Offshore Ventures LLC — "undermined and underfunded" the project.

"By favoring wishful thinking over hard facts, (Buccaneer) turned a blind eye to the amount of time, money, and effort needed to bring such a rig up to operational levels," Archer claimed in its 18-page petition filed in Texas state court, in Harris County.

Specifically, Archer claims Buccaneer underfunded maintenance work on the rig undertaken at a shipyard in Asia and moved the rig to Alaska before crews finished the necessary work, including "installation of the mud treatment and conditioning systems, refurbishment of deep well riser systems, winterization of exposed working areas, full commissioning of all drilling systems, and a

see **ARCHER RESPONDS** *page 14*

NATURAL GAS

ASAP to carry lean gas

In-state gas line plan simplified — no NGLs, lower pressure, no straddle plant

By KRISTEN NELSON
Petroleum News

Plans for ASAP, the Alaska Stand Alone Pipeline, have been simplified, with the proposal to ship natural gas liquids removed from the plan, allowing for lower pipeline pressure and easier offtake along the line.

The optimized plan also has a larger, 36-inch diameter pipe, allowing the project to use industry-standard pipe, fittings and valves, Frank Richards told the Alaska Legislature's Joint In-State Gas Caucus Dec. 20.

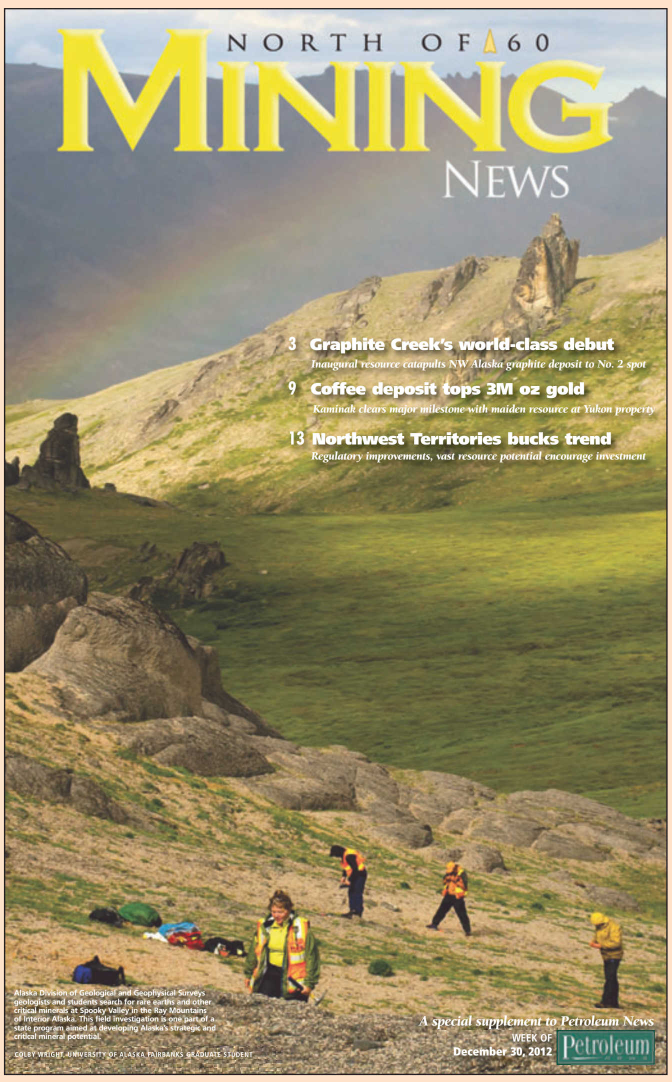
Richards, manager of pipeline engineering for the Alaska Gasline Development Corp., established by the Legislature in 2010 to develop a natural gas pipeline project, said the new design premise contrasts with the proposal presented to the Legislature in 2011, which called for a 737-mile, 24-inch, high-pressure line. The proposed pressure, 2,500 pounds per square inch, was required because of the enriched gas composition, he said.

The "The higher pressure of 2,500 psi meant that we were not at industry standard piping, fittings and valves," Richards said.

But the 2,500 psi pressure meant that a straddle plant was required to deliver natural gas to Fairbanks, "a plant that would allow the natural gas liquids that were entrained in that gas stream to be pulled out, gas

see **LEAN GAS** *page 16*

December Mining News inside



The December issue of North of 60 Mining News is enclosed.

Furie says looming $15 million fine is scaring away investors

The federal government has yet to collect a $15 million Jones Act fine against Furie Operating Alaska LLC. But the company's president says Furie is feeling the pain anyway.

The looming penalty, and the refusal of authorities to mitigate it, "has made it difficult for Furie to secure investors in its resource exploration and development venture," Furie's president, Damon Kade, said in a Dec. 14 declaration filed in U.S. District Court in Anchorage.

U.S. Customs and Border Protection assessed the penalty for an alleged violation of the Jones Act, a shipping law. CBP is an agency within the Department of Homeland Security.

The Jones Act requires that cargo transported between

see **FURIE FINE** *page 15*

New AGDC bill to be offered, separating agency from AHFC

MIKE HAWKER

The Alaska Gasline Development Corp., AGDC, was established by the Alaska Legislature in 2010 to develop an in-state natural gas pipeline, called ASAP — the Alaska Stand Alone Gas Pipeline.

AGDC was set up as a subsidiary of the Alaska Housing Finance Corp. with a legislative mandate to get North Slope natural gas to Alaska consumers at the least possible cost. The original legislation, House Bill 369, established a timetable for the project and required that a project be presented to the Legislature by July 2011.

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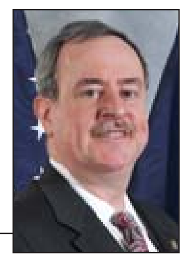

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● GOVERNMENT

Court rejects Shell air permits appeal

9th Circuit Court upholds Environmental Appeals Board decision in appeal against air quality permits for Noble Discoverer drillship

By ALAN BAILEY

Petroleum News

COURTESY SHELL

The Noble Discover, the drillship that Shell is using for exploratory drilling in the Alaska Arctic outer continental shelf.

The U.S. Court of Appeals for the 9th Circuit has rejected an appeal against the Environmental Protection Agency's approval of air quality permits for the Noble Discover, the drillship that Shell is using for exploratory drilling in the Alaska Arctic outer continental shelf. Shell is using the Noble Discoverer primarily for drilling in the Chukchi Sea, although the company had obtained two air quality permits for the vessel: one for the Chukchi Sea and one for the Beaufort Sea.

In a Dec. 26 decision the 9th Circuit court upheld both of the permits.

The EPA issued the Noble Discoverer's air permits in September 2011. The permits were major Prevention of Significant Deterioration permits, rather than minor permits of a type that had previously run aground in litigation.

The Native Village of Point Hope and a group of environmental organizations subsequently appealed to the Environmental Appeals Board over the issue of the permits. And, after the Appeals Board turned down the appeal in January 2012, the appeal moved to the 9th Circuit Court.

Two questions

The court case essentially revolved around two questions: whether vessels in the fleet supporting the drilling vessel should be required to have best available emissions control technology when operating within 25 miles of the drillship, and whether the EPA was correct in allowing a 500-meter zone around the drillship to be excluded from ambient air quality requirements.

Under the terms of the Clean Air Act a stationary industrial emissions source needs to use best available technology to minimize air emissions. And a drillship, moored on site for a drilling operation, is clearly a stationary emissions source. It also appears clear that a support vessel attached to the drillship during a drilling operation is also part of the stationary source.

But the statute is ambiguous regarding whether support vessels, freely moving but operating within 25 miles of the drillship, are also part of the stationary source, and hence subject to the need for best available emissions technology. The EPA had included emissions from the support fleet as part of a determination that Shell needed a major air permit for the Noble Discoverer, but the agency had not viewed mobile vessels of the support fleet as part of the drilling stationary source.

The 9th Circuit court said that it defers to the EPA's "reasonable construction of the statute," as also adopted by the Environmental Appeals Board, that the best available technology requirements do not apply to support vessels not attached to the drillship.

Exclusion zone

The question of the 500-meter zone around the drillship relates to the application of the Clean Air Act on land, where air quality standards typically apply outside the perimeter fence of an industrial facility. Agreeing that considering the gunwales of the drillship as the facility's "fence" to be unreasonable, the EPA had granted a request by Shell that a 500-meter exclusion zone imposed by the U.S. Coast Guard around the vessel should not be subject to ambient air quality requirements.

The court has agreed with EPA's position on this, saying that, because the public is barred from entry to the exclusion zone, the perimeter of the exclusion zone performs a similar function to the perimeter fence of a land-based facility. EPA regulations define ambient air as the portion of the atmosphere, external to buildings, to which the general public has access, the court said in its Dec. 26 decision document.

The 9th Circuit Court is still considering a similar appeal against the air quality permit for the Kulluk, the floating drilling platform that Shell is using for exploratory drilling in the Beaufort Sea. Shell was able to proceed with its Arctic drilling operations using the Noble Discoverer and the Kulluk in the summer of 2012 while the air quality permit appeals were in progress. The company drilled one top-hole section of a well in the Chukchi Sea and one top hole in the Beaufort. ●

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FINANCE & ECONOMY

New Cook Inlet tugs arriving soon

Tesoro, which operates a refinery at Nikiski, is bringing upgraded tanker assist tugs to Cook Inlet, says a nonprofit organization that monitors the oil industry.

The tug Millennium Star was scheduled to relieve the tug Vigilant on Jan. 1 at Nikiski, the Cook Inlet Regional Citizens Advisory Council said.

"Along with an ice-strengthened hull for Cook Inlet's harsh ice conditions and heated decks and tanks, the Millennium Star also has keel coolers, unlike the Vigilant's raw water cooling system, which was problematic in Cook Inlet's icy cold waters," the council said.

Seattle-based Harley Marine Services operates the Millennium Star, while the Vigilant belongs to Crowley Maritime.

It won't be long before the Millennium Star itself is replaced with another Harley tug, the Robert Franco, now under construction in Washington state.

The Robert Franco is scheduled to arrive in April as the permanent tug in Cook Inlet, the council said.

—WESLEY LOY

● FINANCE & ECONOMY

Taking stock of future

Athabasca Oil Corp. off list of takeover targets, but continues negotiating possible oil sands JV, while prowling for partnership

By GARY PARK

For Petroleum News

Athabasca Oil Corp., AOC, is having to chart a fresh course after absorbing unknown collateral damage from newly imposed government limits on how much foreign ownership is acceptable in Canada's oil sector.

With PetroChina holding majority stakes in two oil sands projects, representing potential combined output of 400,000 barrels per day, AOC has long been viewed as one of the likeliest targets to be snapped by a foreign state-owned enterprise, SOE, at a fat share price premium.

But that prospect has been shelved, while the company figures out how to achieve its objectives in both the oil sands and through joint-venture arrangements in the shale gas regions of Western Canada.

In addition to its C$1.9 billion deals with PetroChina for 60 percent of the Dover and 100 percent of the MacKay River projects, AOC recently signed a memorandum of understanding with an unnamed third party — widely believed to be state-owned Kuwait Petroleum Corp., with Spain's Repsol also identified as a candidate — to develop its Hangingstone and Birch oil sands properties.

But any or all of those deals could be placed in doubt because of the Canadian government's new restrictions on foreign investment in Canadian energy firms, said Mark Friesen, an analyst with RBC Dominion Securities.

"While investors may view (the government statements on the outlook for joint-ventures) as positive for AOC's chances of announcing a new joint-venture partnership, we do see increased risk in completion of the joint ventures with an SOE and a possible extension of closing timelines, as the government has the authority to review these investments on a case-by-case basis," he said in a research note.

AOC optimistic

AOC Chief Executive Officer Sveinung Svarte said he is optimistic the joint venture for Hangingstone and Birch will be secured.

But he conceded AOC is "giving some time for a deal to close and it's difficult to predict a timeline."

Rick Koshman, AOC's vice president of projects and thermal operations, said the potential investor is waiting to get the go-ahead from its own authorities, strengthening speculation that Kuwait Petroleum is the frontrunner.

"There are external parties they need to deal with, government agencies, and we're waiting for them to go through their process," he said. "We still feel them to be a potentially very good partner."

However, Koshman said the new government rules are unlikely to derail the negotiations, since SOEs are still permitted to buy minority stakes.

"We're not looking for a change of control," he said. "We are looking for joint ventures to be 50 percent or less."

Hangingstone is AOC's most advanced oil sands holdings, with first production expected by the end of 2014, starting at 12,000 bpd within two years, while Birch could eventually support 155,000 bpd.

Regulatory process at Dover

Meanwhile, the regulatory process is under way for the 250,000 bpd Dover project, with construction due to begin in 2014 and first oil scheduled for 2016.

AOC has already sanctioned the initial phase of Hangingstone, pegging the cost at C$536 million, and allocating 60 percent of its 2013 capital budget of C$798 million, to the project.

The company also plans to spend C$236 million in 2013 to explore and produce light oil, with 60 percent of that amount earmarked for the liquids-rich Montney formation in northwest Alberta, where developing 680,000 contiguous acres with Slave Point oil potential would cost "just too much" for the company to tackle alone, Svarte said.

AOC's Duvernay land base is comprised of more than 350,000 high-graded net acres, of which about 200,000 acres are located in the Kaybob, in the heart of the fairway.

Company President Bryan Gould said AOC has "moved swiftly up the learning curve in terms of understanding the fracture characteristics of the liquids-rich Duvernay reservoir (while) innovative completion techniques have yielded strong production test results," with three wells expected to be on production by the end of 2012.

He said AOC facilities are now capable of handling up to 36,000 barrels of oil equivalent per day of oil and condensates and 48 million cubic feet per day of gas. The light oil division is expected to exit the first half of 2013 with 11,000-13,000 boe per day of production.

"We have done most of the heavy lifting with respect to constructing our 100 percent-owned production facilities and infrastructure," Svarte said.

He said recent industry deals in the Duvernay — notably Encana's C$2.18 billion joint venture with Phoenix Duvernay Gas, a wholly owned subsidiary of PetroChina and ExxonMobil's C$2.6 billion takeover offer for Celtic Exploration in the neighboring Montney — have been "rather encouraging."

However, despite its need for a partner, AOC will wait another six months to see "how the type curves play out," before seeking a joint-venture partner, he said. ●

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FACILITIES

BRPC permitting Mustang road

Shortly after getting state backing for the project, Brooks Range Petroleum Corp. has begun permitting a gravel road to its Mustang prospect, in the central North Slope.

The independent is seeking an easement on state lands for a 100-foot wide road running some 5.06 miles from the Kuparuk River road system to the proposed site of the Mustang pad and gravel mine in the Southern Miluveach unit, on the southwest corner of Kuparuk.

The road, the pad and the mine are included in the package of infrastructure Brooks Range Petroleum Corp. is building at Mustang in partnership with the Alaska Industrial Development and Export Authority, through a joint venture executed in December. The $25 million project also includes a small access road from the pad to the mine, and a winter ice road. AIDEA is paying up to $20 million of the total project cost, with Brooks Range Petroleum paying the remainder, including any cost overruns, should they occur.

The deal also involved creating a company, Mustang Road LLC, to build, operate and maintain the infrastructure. Mustang Road is not listed on the current public notice.

The Alaska Department of Natural Resources is taking comments through Jan. 18.

While the Division of Mining, Land and Water typically handles easement applications, it delegated its adjudication authority to the Division of Oil and Gas for this particular case.

—ERIC LIDJI

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● NATURAL GAS

Homer gas pipeline inching forward

State prepares easement for small distribution line as Homer and Kachemak City move ahead on proposals for funding citywide grids

By ERIC LIDJI
For Petroleum News

In an early small step toward bringing natural gas to the Homer area, the state is preparing an easement for a small distribution line heading south from Anchor Point.

The Division of Mining, Land and Water is taking comments on an application from Enstar Natural Gas Co. for two small easements through state land in the region.

The easements would serve an 8-inch high-density polyethylene pipeline running some 1,116 feet. The small line would eventually connect to a trunk line into Homer.

The state is taking comments through Jan. 21.

As Enstar works to connect Homer and neighboring Kachemak City to the Southcentral regional gas transmission grid, the two cities are studying how to fund the distribution grids required to deliver gas from the main line to individual homes and businesses.

In July, Homer initiated a citywide Natural Gas Special Assessment District to finance the estimated $12.1 million build out.

In July, Homer initiated a citywide Natural Gas Special Assessment District to finance the estimated $12.1 million build out. If approved, the district would cost each property owner as much as $3,283 over 10 years. The city sent out notices about the proposed district in November and is taking objections from property owners through Jan. 25. If at least 50 percent of property owners object, the city cannot move forward with the project.

A few weeks before the deadline, on Jan. 10, Enstar is holding a public meeting at Homer High School to answer general questions about natural gas expansion and conversion. And the city of Homer is holding public hearings on the district on Jan. 14 and Jan. 28.

In Kachemak City, a small coastal community to the east of Homer — and only about one tenth of the size of its larger neighbor — officials are looking into forming a local investor group to finance its distribution system. As currently envisioned, the group would require a $50,000 investment and would pay an estimated 5 percent interest rate.

The goal would be to raise $600,000 to add to the $400,000 the city is able to put toward the estimated $1 million project. The city wants to find between 12 and 14 investors, and already has eight lined up, Kachemak City Mayor Phil Morris told the Homer Tribune. ●

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● GOVERNMENT

NMFS lists ringed and bearded seals

Says that shrinking Arctic sea ice extent threatens survival of species; Alaska state administration considers suing the agency

By ALAN BAILEY
Petroleum News

The National Marine Fisheries Service, or NMFS, has listed under the Endangered Species Act, or ESA, four subspecies of ringed seals and two population segments of bearded seals. One of the types of ringed seal, the Arctic ringed seal, and one of the bearded seal population segments, the Beringia bearded seal, exist in U.S. Arctic waters and have been listed as threatened.

The listings come as part of a trend to list animals that depend on Arctic sea ice as part of their habitat, on the assumption that the decline in the extent of sea ice as the climate warms will ultimately threaten the species' existence. Ringed seals, for example, nurse and protect their young in snow caves that are threatened by factors such as late ice formation in the fall and early break-up of spring ice, NMFS says.

In 2008 the Center for Biological Diversity petitioned NMFS to list the seals and in October 2009 the agency proposed listing the animals. Following a public comment period on the proposal, in March 2011 NMFS decided to ask four scientists with appropriate expertise to review the proposal. Then, given disagreements over parameters such as model projections of future Arctic sea-ice and snow cover, NMFS extended the deadline for the listing decision, to allow time for independent peer reviews.

The court ordered a decision by Dec. 21 and NMFS has now responded to that order.

Court order

In September of this year the Center for Biological Diversity sued NMHS in federal Alaska District Court over the agency's failure to make a listing decision at the extended deadline. The court ordered a decision by Dec. 21 and NMFS has now responded to that order.

"Our scientists undertook an extensive review of the best scientific and commercial data. They concluded that a significant decrease in sea ice is probable later this century and that these changes will likely cause these seal populations to decline," said Jon Kurland, protected resources director for NMFS' Alaska region, when announcing the listing decision on Dec. 21. "We look forward to working with the State of Alaska, our Alaska Native co-management partners, and the public as we work toward designating critical habitat for these seals."

The state administration, which views the succession of climate-change-related ESA listings as federal overreach, threatening economic activity in the state, is rather less enthusiastic about the listings than the federal regulators — Gov. Sean Parnell announced Dec. 21 that the state is considering legal action against NMFS over the decision.

"The ESA was not enacted to protect healthy animal populations," Parnell said. "Despite this fact, the NMFS continues the federal government's misguided policy to list healthy species based mostly on speculated impacts from future climate change, adding additional regulatory burdens and costs upon the State of Alaska and its communities, and wresting away Alaska's sovereign interest in managing its own wildlife and resources."

Murkowski alarmed

Sen. Lisa Murkowski expressed her alarm at the decision.

"I believe that Alaska's wildlife must be protected, but not by relying on overbroad, overreaching analysis that runs counter to the abundant seal populations we presently see," Murkowski said. "There is something misguided about policy that is guaranteed to cause real economic impact on the horizon based on a hundred-year hunch. No wonder NOAA decided to release this decision the Friday before Christmas, hoping it won't register with Alaskans."

"NMFS' decision is, in our opinion, not consistent with the text and policy of the ESA or the best available science," said Kara Moriarty, executive director for the Alaska Oil and Gas Association. "The decision to list ringed and bearded seals is based on how climate change might affect these species 100 years from now, despite their populations currently being healthy and abundant. That's bad precedent for making evidence-based decisions that have real impacts for Alaska." ●

Contact Alan Bailey at abailey@petroleumnews.com

● GOVERNMENT

AOGCC proposes new state fracking regs

Regulations would require water monitoring, disclosure of hydraulic fluid contents and implementation of well integrity rules

By ALAN BAILEY
Petroleum News

Presumably in anticipation of the testing and development of oil production from source rocks in Alaska, the Alaska Oil and Gas Conservation Commission, or AOGCC, has proposed implementing new state regulations for the hydraulic fracturing of wells. Hydraulic fracturing, commonly known as "fracking," in conjunction with the drilling of horizontal wells is a key technique used in source rock oil production. The new regulations supplement existing Alaska regulations for hydraulic fracturing, which has been conducted for many years in the state in conjunction with conventional oil production.

Notification

The new regulations would require anyone proposing to hydraulically fracture a well to notify landowners, surface owners and operators for land within one-quarter mile of the well-bore of the planned operation. An application for a permit for hydraulic fracturing must identify any water wells with a quarter-mile of the operation, with water sampling from any water wells having to be done before and after the fracking is carried out.

The permit application must also state the estimated volume of fracking fluid to be used, and the names and quantities of all materials to be used in the fluids. And the application must specify the designed height and length of proposed well fractures.

The regulations spell out a number of requirements to assure well integrity during fracking operations. Those requirements include testing standards for production well casing, testing requirements drill strings used in fracturing and requirements for a pressure relief valve between a well and the pump used to inject hydraulic fluid into the well.

The well operator must also specify which rock zone is to be fractured, specify the depth of that zone and specify the depths of any neighboring freshwater aquifers.

Report fluids used

After a fracking operation has been completed, the well operator must report to AOGCC the amount and type of material that was pumped into the well, including the names of all chemical additives used. The operator must also post information about the fracking operation on the website of the Ground Water Protection Council and Interstate Oil and Gas Compact Commission.

In early December AOGCC Commissioner Cathy Foerster told Law Seminars International's Energy in Alaska conference that, although the commission already has adequate regulations in place to ensure the safety of hydraulic fracturing, the commission would introduce new regulations in view of recent advances in fracking technology and in recognition of public concerns about the technique.

AOGCC requires public comments on its proposed regulations by Feb. 4. ●

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● LAND & LEASING

W Canada cash cow runs dry

Land auctions across the border record sharp decline from 2011; turnaround based on establishment of new unconventional fairways

By GARY PARK
For Petroleum News

Sales of exploration rights in Western Canada's three dominant petroleum provinces turned this year into a pale shadow of their role as a key source of government revenue over the past decade.

Even Alberta, which collected a respectable C$1.12 billion, was left to ruefully compare that with last year's record haul of C$3.64 billion.

Saskatchewan tumbled to C$105.7 million from its C$249 million in bonus bids in 2011 and British Columbia continued the dramatic slide in its land auctions over the last four years, collecting $139.3 million, its lowest calendar-year return since C$96.34 million in 1998.

In Alberta a total of 3.16 million hectares (7.8 million acres) changed hands at a per-hectare average of C$354.85, compared with 4.6 million hectares at an average C$790.33 in 2011, with the province ending its land sales for 2012 by selling 267,994 hectares at an average C$265.88.

Brad Hayes, president of Petrel Robertson Consulting, said 2013 is likely to be a relatively slow year unless someone identifies a new play concept or area.

But Perdo Antunes, co-author of the board's report, said there are downside risks associated with LNG development, notably a collapse in crude prices which could be a drag on LNG prices.

"Prospectivity looks to be relatively limited already," he said. "We will continue to see the off high-priced parcel spring up within established fairways, but we need to see new unconventional fairways established if we are to see an increase in the overall land sale revenues."

'Cautiously optimistic'

In Saskatchewan, Energy Minister Tim McMillan was encouraged that his province's final sale attracted more than C$1 million in successful bids for two oil sands permits, requiring a minimum work commitment expenditure on exploration over the five-year term of the permits.

"The province is cautiously optimistic that the results of this exploratory work will provide further insight into the potential of the resource," he said, pointing to the steady extension of Alberta's oil sands activity into Saskatchewan.

However, Hayes noted that the Saskatchewan oil sands are "relatively remote from infrastructure compared with most Alberta projects, so that will add greatly to capital expenditures."

"With there being far fewer thermal projects and no oil sands mining in Saskatchewan, investors might discount value with the thought that the regulatory regime may be less flexible than in Alberta," he said.

Hayes said that although there can be oil sands deposits in Saskatchewan, until they are fully appraised, investors will see a relatively large risk that resource volumes and reservoir continuity may be unable to support an economic project.

On the upside, British Columbia still records good per-hectare bids, because there is long-term value in the main drivers, such as the Montney and other unconventional reservoir fairways, Hayes said.

"Compared to Alberta and Saskatchewan, there is not as much bidding on small or marginal plays, which can bring the overall average land price down in those provinces," he said. "So it appears to me that land sales in British Columbia are more focused on high-value, hot plays."

B.C. sales 'relatively modest'

Hayes predicted that British Columbia sales will be "relatively modest" in 2013 "unless someone identifies a new unconventional play fairway that attracts large bids over large areas. Expiries and reversions will always happen, but they are likely to attract only occasional large bids in isolated parcels."

British Columbia has long since accepted that natural gas royalties will be lower than expected for the 2012-13 fiscal year because of weak commodity prices.

On the positive side, the Conference Board of Canada forecasts British Columbia will lead natural gas investments in Canada in the 2012-35 period, totaling C$181 billion, followed by Alberta at C$151 billion, assuming LNG export projects go ahead.

The province's Liberal government under Premier Christy Clark, which faces possible defeat in a May election, now forecasts gas royalties of C$157 million, down dramatically from the original budget forecast of C$398 million and from the C$339 million collected in 2011-12.

Moody's Investors Service has reacted by issuing a negative outlook based on "risks top the province's ability to reverse the recent accumulation in debt with the softened economic outlo0ok, weaker commodity prices and continued expense pressures."

On the positive side, the Conference Board of Canada forecasts British Columbia will lead natural gas investments in Canada in the 2012-35 period, totaling C$181 billion, followed by Alberta at C$151 billion, assuming LNG export projects go ahead.

But Perdo Antunes, co-author of the board's report, said there are downside risks associated with LNG development, notably a collapse in crude prices which could be a drag on LNG prices. ●

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● ENVIRONMENT & SAFETY

Deepwater Horizon: a scientific response

Newly published papers document how the science community responded to a disaster of unprecedented magnitude in the Gulf of Mexico

By ALAN BAILEY
Petroleum News

With countless thousands of words having already been written about the Deepwater Horizon disaster in the Gulf of Mexico, it may be tempting to think that anything that could be said about this calamitous event has already been put into print. But a series of scientific papers published in early December in the Proceedings of the National Academy of Science puts a particular scientific slant on the events following the April 20, 2010, blowout of BP's Macondo well, and the response to the subsequent spewing of oil into the waters of the Gulf.

A scientific perspective can perhaps put some objectivity around events that inevitably trigger high levels of emotion.

One of the papers in the Proceedings overviews the scientific findings and experience in the Deepwater Horizon response. This paper is authored by officials from several federal agencies, including U.S. Geological Survey Director Marcia McNutt and Energy Secretary Steven Chu, with Jane Lubchenco, the then administrator of the National Oceanic and Atmospheric Administration, or NOAA, as lead author.

Unprecedented, unprepared

The paper emphasizes the unprecedented nature of the Deepwater Horizon disaster and the initial lack of adequate technologies for responding to it.

"The situation of the Macondo blowout was unprecedented, with the oil spewing forth into an extreme ocean environment — deep, cold and high pressure — but rapidly spreading to mid-waters, the surface and the atmosphere," the paper says. "Experience and response methods applicable for other oil spills in many cases proved either impossible to apply or ineffective."

In particular, BP's government-approved spill response plan did not take account of the presence of deep, suspended microscopic oil droplets in the seawater, even although the formation of these droplets had been predicted as likely to occur, the paper says.

And the evolving response to the out-of-control well involved cross-agency cooperation between government scientists and the vital involvement of scientists from academia and private institutions, the paper says.

Oil flow rates

One particularly difficult issue that emerged from the early days of the response was the question of just how much oil was escaping from the well.

"The lack of reasonable estimates of flow rate early on was problematic from the perspectives of both communications and response, but the lack was caused by real uncertainty rather than any attempt to hide information or underestimate numbers," the paper says. "It is true that much of the response did not depend on knowing the exact rate, but some of it did, particularly the capacity to capture oil directly from the well."

As the response proceeded, new methods of estimating flow rates emerged. For example, NOAA and academic scientists developed a method of determining which components of the oil escaping from the well actual reached the surface of the sea, thus enabling an estimation of well flow rates by the detection of oil components escaping into the air.

Airborne, surface and subsurface chemical measurements ultimately led to a consistent picture of the dynamics of oil flow, indicating that only about half of the oil and none of the methane gas escaping from the well ever reached the sea surface, the paper says. And echo-sounder imaging of oil droplets in the water, carried out by a surface ship, provided an additional means of estimating oil flow rates.

Ultimately, the scientists estimated an initial oil flow rate of about 62,000 barrels per day, declining to around 53,000 barrels per day that the time the well was shut in.

Final tallies for volumes of recovered oil indicated that 5 percent of the spilled oil was burned, 3 percent was skimmed and 17 percent was recovered directly from the riser pipe from the well, the paper says.

Fate of the oil

So where did the remaining oil end up?

Repeated sampling of offshore waters showed that within 19 days of eventually shutting in the well, oil in the water had dissipated to background levels, the paper said. However, sediment sampling revealed grounded oil in deep areas around the wellhead; in deep-water sites to the northeast and southwest of the well; in many shallow coastal areas around oiled marshes; and near some beaches.

The assessment of oil contamination in deep-water animals also pointed to some significant accumulation of oil on sediments, while coral communities, mostly within 20 kilometers of the well, were also impacted.

Weathered oil samples in beach and nearshore environments showed 86 to 98 percent depletion of polycyclic aromatic hydrocarbons, with further depletion to 20 percent of current levels anticipated within five years, the paper says. According to information published by the Environmental Protection Agency, or EPA, polycyclic aromatic hydrocarbons are a component of weathered crude oil that can be toxic, depending on which hydrocarbons are present, and on the level of the contamination.

Dispersants

One aspect of the Deepwater Horizon incident that sparked particular controversy was the decision to use chemical oil dispersants, including the injection of dispersants directly into the oil flowing from the well. Dispersants break oil into minute droplets, thus accelerating the rate at which naturally occurring bacteria decompose the oil in the water and consequently reducing the impact of spilled oil on fisheries and on the ecologies of coastlines and estuaries.

But people have questioned the potential toxicity of the dispersant chemicals. And the accelerated bacterial action on the oil can reduce oxygen levels in the water, perhaps adversely impacting water-living creatures.

Factors leading to a decision to inject dispersants directly into the escaping oil included a view that this method of dispersant application would require less dispersant than other methods while maximizing the exposure of oil to the chemicals before the weathering and emulsification of the oil occurred. And there would be less exposure of response workers to dispersant chemical and to organic compounds from

see **HORIZON RESPONSE** page 8

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HORIZON RESPONSE

the oil, the paper says.

On the other hand there were concerns about a lack of understanding of the potential consequences of the dispersant application, the possibility of severe hypoxia in the seawater and the potential for dispersed oil and dispersants to damage subsea flora and fauna.

"Balancing these tradeoffs was not easy, but the potential for more rapid degradation of hydrocarbons was compelling," the paper says.

Monitoring results

In the event, the EPA administrator decided to allow the subsea injection of dispersants to proceed, subject to the strict monitoring of the amount of dissolved oxygen in the water; additional toxicity screening of the dispersants; and the rapid communication of data to responders and the public.

As dispersant application proceeded, repeated water sampling showed a drop in oxygen levels, but not to levels considered hypoxic. And assessments of dispersal effectiveness through the measurement of oil droplet sizes pointed to an increase in the estimate of the volume of oil dispersed from 8 percent to 16 percent of total oil, the paper says.

Subsequent tests on water and sediment samples from nearshore and offshore locations for the most part failed to find dispersant chemicals at detectable levels, and no samples contained chemical concentrations above benchmarks set as acceptable for aquatic life, the paper says.

No biological impact

EPA's tests of the effect of the dispersants used and of mixtures of oil and dispersants on sample species of Gulf shrimp and silverside fish showed that the dispersants had no biologically significant impact on the organisms. Dispersants were found to be less toxic than mixtures of oil and dispersant, with the oil-dispersant mixture having similar toxicity to oil by itself, the paper says.

However, "additional studies are required before a complete understanding of the tradeoffs with the use of dispersants is known, including potential impacts of dispersants, dispersed oil and oil alone on the plethora of other species in the Gulf, especially plankton and juvenile stages," the report says.

Seafood safety

With the Gulf of Mexico being a major venue for the U.S. seafood industry, one crucial issue facing responders to the Deepwater Horizon disaster was the question of keeping Gulf seafood safe. And as a first step in the response, government authorities closed oiled or potentially oiled waters to fishing, using observed or modeled projections of oil movement. NOAA, the U.S. food and Drug Administration and states on the Gulf coast developed new scientific protocols for determining when waters were safe for a re-opening of fishing or oyster harvesting. For a re-opening, an area had to be free of oil for at least 30 days and to be expected to remain free of oil for at least 72 hours. Repeated tests on different types of seafood had to demonstrate the seafood to be safe for consumption.

Of biggest concern was a dispersant chemical called dioctyl sodium sulfosuccinate. New analytical techniques developed during the Deepwater Horizon response made it possible to determine how much of this chemical was present in seafood gathered from the Gulf, thus ensuring that seafood in re-opened areas posed no health risk. And as part of the response a new rapid method of testing for aromatic hydrocarbons was developed. In total more than 8,000 seafood specimens were tested.

"This extraordinary effort to protect the integrity of seafood seems to have been successful: No tainted seafood was reported to have reached the market," the paper said. "An independent assessment arrived at the same conclusion."

However, after the sight of oil and gas flowing from the Macondo well and, with images of oil covered shores and birds appearing for weeks on end, many people had difficulty in believing that oil was disappearing from open waters, that fish could metabolize aromatic hydrocarbons and that seafood testing was reliable, the paper says.

Role of science

As well as being critically important to the response to the Deepwater Horizon disaster, science is playing a crucial role in assessing the damage caused by the incident and in the efforts to restore the Gulf environment to its pre-spill condition, the paper says. Restoration efforts, which may take years to accomplish, involve determining impacts on natural resources; the planning of damage assessment and environmental restoration; and then the implementation of restoration plans.

In the case of the response to Deepwater Horizon, federal and local government officials overseeing restoration efforts decided on a policy of openness and transparency, allowing public access to data that was collected, the paper says.

Although it may take several years for all of the effects of the oil spill from the Macondo well to become apparent, there have already been new scientific discoveries as a consequence of the disaster. For example, the discovery of microbes and sea conditions that lead to the rapid decomposition of hydrocarbons in the water, the paper says.

Recommendations

And the paper recommends a number of science priorities to address preparations for any future oil spill response emergency. These recommendations include the need for adequate baseline environmental information for any region at risk and the need for an understanding of how offshore ecosystems work. It is important to develop new technologies for rapid reconnaissance and sampling following a spill and to develop more efficient methods for capturing spilled oil at the surface. Research is needed into the effects of dispersants and dispersant/oil mixtures on a variety of organisms. And there needs to be research into the social science of oil spills, including the impacts on communities and the costs of oil spills to an impacted region and the nation, the paper says.

The paper also says that, with knowledge of oil flow rates being so important to the planning and execution of response strategies, devices that can provide oil flow rates should be installed on any equipment used for the extraction of oil.

And adequate spill response preparation is a key to successfully dealing with an oil spill emergency.

"The importance of preparedness cannot be overstated," the paper says. "Despite significant advances in technology that allowed drilling in deep waters, comparable progress had not been made in devising methods that would have enabled us to stop the flow from deep wells or deal with a spill of the magnitude seen in Deepwater Horizon. Both could and should have been anticipated." ●

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The science behind Macondo well capping

After the worst oil spill in U.S. history, BP's Macondo well was finally capped on July 15, 2010. But the decision process leading to that well capping proved far from easy, given the potential for the capping operation to result in a seafloor oil leak that would have proved much more difficult to deal with than the leak from the well itself.

A paper published in early December in the Proceedings of the National Academy of Science by scientists involved in the well capping decision describes the science behind the decision that stopped the flow of oil from the well.

Leading contender

From quite early in the response effort the use of a device known as a capping stack to close off the well became a leading contender for controlling the spill. But, with the well penetrating poorly consolidated sediments beneath the seafloor, the possibility of the downhole pressure buildup following a capping operation causing a catastrophic seafloor oil leak became a major concern. The exceptional subsurface pressure gradient in the sediments at the well site made the sediments particularly susceptible to fracturing, potentially enabling a seafloor oil leak to occur following a well breach, the paper says.

In May 2010 an operation called "top kill" involved pumping drilling mud down the well. And when this operation failed to stop the blowout BP engineers postulated the possibility of a wellbore breach having allowed mud to escape from the well — the existence of such a breach would likely provide a route for oil to escape from the well

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● EXPLORATION & PRODUCTION

EIS describes two-stage Shadura project

NordAq's gas development could feature six wells at site within Alaska's Kenai National Wildlife Refuge; initial test well is key

By WESLEY LOY
For Petroleum News

Federal officials have released a draft environmental impact statement for NordAq Energy Inc.'s proposed Shadura natural gas development in Alaska's Kenai National Wildlife Refuge.

NordAq plans to drill up to six production wells at a site about 13 miles northeast of Nikiski, the center of the Kenai Peninsula oil and gas industry.

The U.S. Fish and Wildlife Service, which manages the refuge, is taking public comments on the draft EIS until Feb. 4. Find the document at 1.usa.gov/dkeiCw.

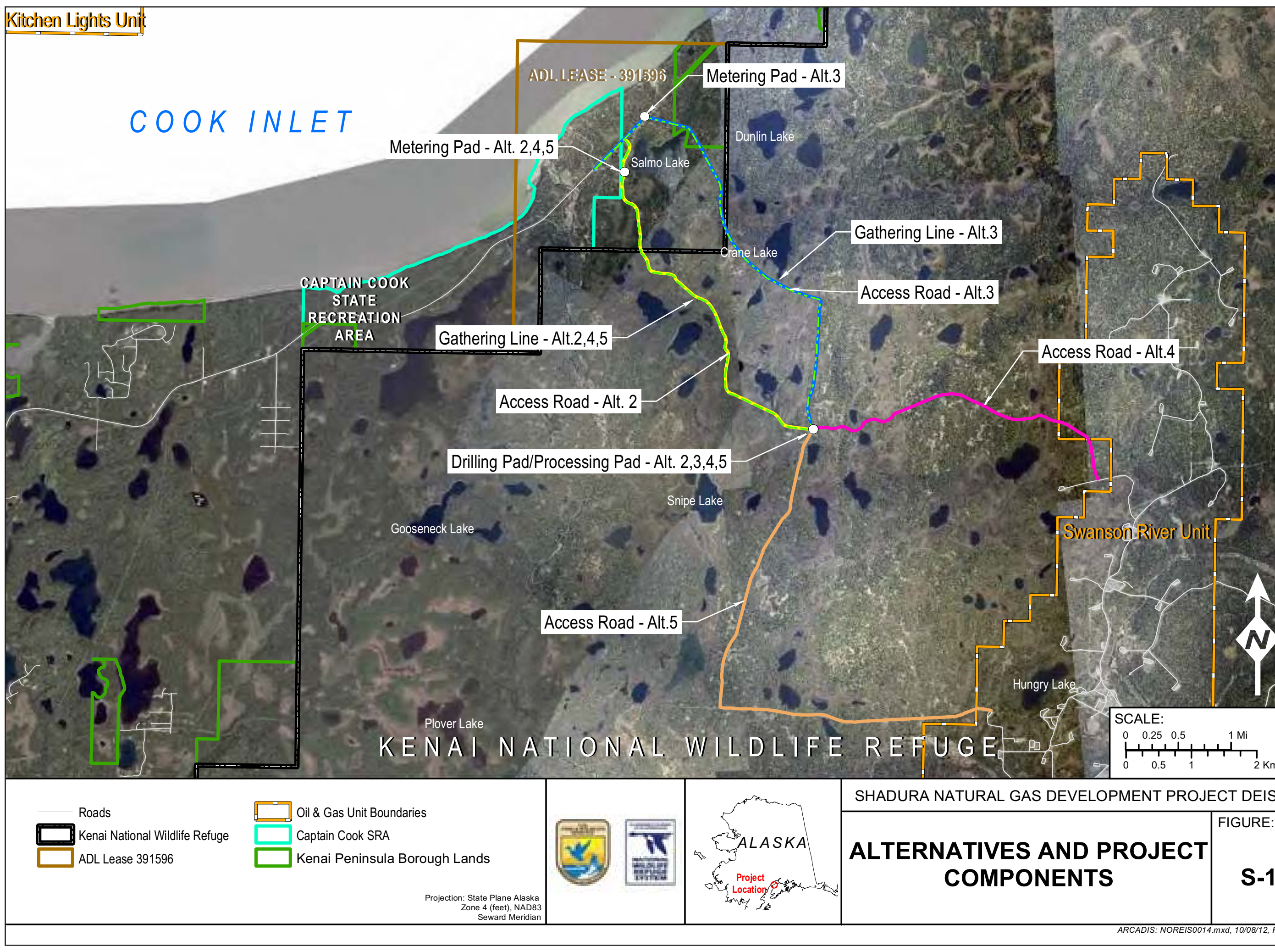
NordAq is a small, Anchorage-based independent. Its president and part owner, Bob Warthen, is a geologist and veteran of the Cook Inlet oil and gas scene, having worked as a Unocal manager and as a consultant.

Refuge's oil and gas legacy

The Kenai National Wildlife Refuge is a vast preserve encompassing nearly 2 million acres.

Franklin D. Roosevelt established the refuge in 1941. It originally was known as the Kenai National Moose Range. The refuge is home to a fabulous array of wildlife including moose, bears, lynx, wolves, bald eagles, salmon and trout, to name a few.

The refuge also has hosted oil and gas development since the 1950s. The EIS says the refuge has 13,252 acres of active oil and gas leases. Several oil and gas units have been established within the refuge, including the Swanson River, Beaver Creek and Birch Hill units.



NordAq's proposed Shadura gas development is in the northwest portion of the refuge, west of the Hilcorp-operated Swanson River unit.

The federal government owns the land surface in the project area, while Cook Inlet Region Inc. owns the subsurface oil and gas estate. CIRI has entered into a

see SHADURA PROJECT page 11

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WELL CAPPING

following a capping operation, thus increasing the probability of a catastrophic leak.

To evaluate the possibility of an subsurface oil blowout, BP and a well integrity team consisting of scientists and engineers from government agencies and academia agreed on a test involving the temporary capping of the well to enable well pressure monitoring, with a procedure to re-open the well within a fairly short time if pressures remained below a specified level.

In the event, when in mid-July the cap was applied, the oil pressure in the well did climb above a level below which there would have been a clear indication of a well breach. But unfortunately when the pressure subsequently stopped climbing the pressure was still too low to completely rule out the possibility of a breach being present.

So, to ensure that no subsurface blowout would occur, government regulators ordered that the wellbore should be re-opened after 24 hours, the paper says.

Meantime, to account for the observed maximum well pressure attained after the capping operation, scientists plugged reservoir data supplied by BP into a U.S. Geological Survey computer model originally designed to simulate the flow of groundwater through subsurface aquifer rocks. By simulating what would happen were there no well breach, given estimated oil flow rates from the well, the scientists were able to determine that the observed lower-than-expected well pressures following capping were likely to have resulted from oil depletion in the subsurface oil reservoir following the well blowout.

And, given this explanation for the observed pressures, the government allowed the capping operation to continue beyond 24 hours, but with continuous monitoring of well pressure and geophysical surveillance data, and with a re-evaluation of the well capping decision at regular intervals.

The geophysical surveillance included the use of seismic surveys, conducted as frequently as four times per day, to seek early evidence of any flow of oil and gas from the well bore through the surrounding rocks.

With the shut-in of the well extending over several days, new pressure data from the well enabled the near-continuous updating of the reservoir model used to assess the possibility of a well breach. And, with the scientists also refining the assumed reservoir geometry used in the model, the well pressures predicted from the model turned out to be a close match with the pressures measured in the well. It appeared that the well had maintained its integrity following the capping operation.

It subsequently became possible to keep the stacking cap in place until Aug. 2, at which time the use of a relief well enabled the Macondo well to be fully sealed off and cemented.

Success in the capping operation can be attributed to collaboration between the many scientists, engineers and emergency response officials involved; clear protocols for data requests through a well-defined chain of command; the very rapid analysis of diverse datasets; the co-location of government scientists with BP staff; continuous access to required expertise and training; and excellent access to BP's data and mitigation plans, the paper says.

—ALAN BAILEY

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● GOVERNMENT

Alberta needs pipeline cure

By GARY PARK

For Petroleum News

Oil-rich Alberta stands on the brink of its own version of a fiscal cliff and will only be pulled back if opposition to crude oil and bitumen pipelines out of the province can be overcome.

Premier Alison Redford, faced with having to withdraw a staggering C$3 billion from a "sustainability fund" to keep her government's fiscal house in order and halt a ballooning deficit, said that unless new pipelines can be built to new markets Alberta will face more drastic deficits and spending cuts.

She said there has been a "monumental shift" in the economics of Alberta oil as delays in approving and building new pipelines eat into the profits that have long supported both the petroleum industry and the powerful economies of Western Canada.

Alberta Finance Minister Doug Horner weighed in with a blunt warning that North America's oil glut paired with a decline in commodity prices could result in tax increases.

"Everything is on the table," he said, but Redford was unequivocal that there will be no new taxes in the immediate future, despite conceding "we're going to have to do some tough stuff, we're going to have to make some tough decisions."

ALISON REDFORD

Falling oil prices

Horner blamed Alberta's financial woes on falling oil prices, which have seen the Western Canada Select crude tumble drastically in December to a record US$37 per barrel short of West Texas Intermediate.

"I'm really concerned about where those numbers are headed over the short term and the medium term," he said. "If we can solve the market access piece, the long-term outlook for Alberta is still very robust."

Redford said Alberta urgently needs to see new pipeline capacity introduced, spurred on by "a profound change in the way that Canadians look at the world" that includes the importance of getting crude to markets beyond North America.

Russ Girling, chief executive officer of TransCanada, which is anxiously waiting for an early-2013 decision from the Obama administration on the Keystone XL project, said the Western Canadian industry needs to take advantage of the demand for its production from U.S. Gulf Coast refineries and the opportunity to displace 1 million barrels per day of expensive imported crude on the U.S. Eastern Seaboard.

He said TransCanada has been discussing converting part of its underutilized natural gas Mainline to Eastern Canada and the U.S., along with a possible extension of that system.

"We've provided interested parties with the economics of doing that," Girling said. "It's far more attractive than railing it." ●

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● NATURAL GAS

Expanded Panama Canal could reroute LNG

2015 completion of work will allow tankers to move more freely, could edge industry toward global pricing structure similar to oil

By BILL WHITE

Researcher/writer for the Office of the Federal Coordinator

1 2 SERIES

The liquefied natural gas industry awaits with anticipation an event in 2015 that could crack the framework upon which the industry has been built.

Opening a wider Panama Canal that year could disrupt the industry's core economic model that says LNG made in the Atlantic Basin generally gets sold to countries in the Atlantic Basin, while LNG produced in the Pacific-Australia Basin goes to buyers in that region.

If the canal widening and deepening erodes this rule of thumb, the logic of separate natural gas prices in North America, Europe and Asia could start to dissolve, edging the industry toward a more global pricing structure similar to the oil industry.

BILL WHITE

The canal could change the flow of money between LNG buyers and sellers, and that has their attention. Hardly an international gas conference goes by these days without some discussion and speculation about what the expanded canal will mean for the industry's future.

Peruvian LNG routed to Europe? Nigerian LNG tankered to Japan? Gulf of Mexico gas shipped to South Korea? And so on. Relatively little of that cross-pollination occurs now, although some does, especially as Asian demand for LNG spiked in 2011. Almost all of the 11 liquefaction projects proposed for the U.S. Gulf Coast are bets that the canal will open Asian markets to Atlantic Basin liquefaction.

The $5.25 billion canal expansion is one of the world's great transportation infrastructure projects now under way.

Panama is upgrading the 100-year-old canal to accommodate today's superships that don't fit the waterway now. A new, wider set of locks will run parallel to the old locks — sort of like the way interstate highways in the 1960s updated the old U.S. highway system, allowing more traffic and shorter transit times.

The LNG industry operates on a large scale — multibillion-dollar liquefaction plants, colossal tankers — to achieve economies of scale. The fleet's 370 tankers are so big that only 6 percent of them can squeeze through the canal today, and none of them try, Kasper Walet with Amsterdam-based energy consultant Maycroft said at an LNG conference last year. But 80 percent will fit through the canal when the expansion is done.

"It should be a real game changer," Walet said.

Not everyone agrees with that, noting that tanker charters can cost over

see LNG REROUTE page 13

● NATURAL GAS

RCA puts pipeline back out for notice

Spectrum Alaska and a pair of Flint Hills subsidiaries are both interested in building North Slope liquefied natural gas plants

By ERIC LIDJI

For Petroleum News

After a dust-up between two competing liquefied natural gas projects, state regulators are putting a proposed North Slope pipeline for one of them back out for public comment.

In October, Spectrum Alaska LLC applied for a certificate from the Regulatory Commission of Alaska for an 8-inch pipeline to move gas roughly 1,100 feet from existing Prudhoe Bay facilities to a proposed LNG plant south of Flow Station No. 2.

In November, two Flint Hills Resources Alaska LLC subsidiaries proposed a similar system located in the same place. State guidelines require competing projects to file a notice of intent within 30 days of the original application, but the companies claimed the Spectrum application failed to announce this provision, as required by state regulations.

The RCA put the project out for public notice again on Dec. 18, but corrected the notice Dec. 21. Now, the RCA is asking that all prospective shippers on the line file requests for service by Jan. 14 and asking all competing projects to file notices of intent by Jan. 22.

Summer construction

Because the pipeline application process involves a certificate from the RCA and a right of way from the State Pipeline Coordinator's Office, the Flint Hills companies asked the RCA to wait until the SPCO made its decision before proceeding with its determinations.

Spectrum wants the RCA to rule by April 15, to allow for summer construction.

In addition to certification, Spectrum is seeking a waiver of the requirement to file audited financial statements and instead file unaudited statements, and it wants confidentially treatment for the statements and other information in the application.

Spectrum Alaska originally described an LNG system designed to serve North Slope industrial customers, but has since said its system could also serve the Interior and Southcentral markets through existing road and rail infrastructure. As part of a since dissolved joint venture, the Flint Hills companies are applying on behalf of Golden Valley Electric Association, which is seeking to truck LNG to the Interior region. The companies are expected to eventually transfer the application to the electric cooperative.

The Parnell administration recently announced a $355 million package to finance a North Slope liquefaction plant and fund storage and distribution infrastructure in the Interior. ●

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SHADURA PROJECT

lease with NordAq to develop the gas resource.

Federal regulations require the Fish and Wildlife Service to grant "adequate and feasible" access to the owners of inholdings for economic purposes. But the agency can impose conditions to minimize adverse impacts to the environment, including wetlands.

The draft EIS — the agency will issue a final version after taking public comments — is meant to assist the agency in arriving at a decision on Shadura access. The document looks at five alternatives: a "no action" alternative, NordAq's proposed development (Alternative 2), and three variations on the route of the access road to the site.

Two of the alternatives (Alternatives 4 and 5) would have the access road coming from the south or east, out of the Swanson River field and its existing road system. NordAq proposes going in from the northwest, off the Kenai Spur Highway.

The Fish and Wildlife Service has not yet chosen a "preferred" alternative, the EIS says.

Two construction stages

NordAq, along with several other companies, are looking to alleviate a looming gas shortage in Southcentral Alaska, which long has relied on gas from the Kenai Peninsula and around the Cook Inlet to heat and power homes and businesses. Mature fields in the region that once held ample supplies are now depleting.

NordAq in early 2011 drilled a wildcat exploratory well, the Shadura No. 1. The company has not made clear the size of its apparent gas discovery.

Warthen told Petroleum News on March 22 that the 14,624-foot well was drilled at the edge of the reservoir. The proposed Shadura development pad is more than a mile due east of the wildcat.

The EIS says NordAq proposes a two-stage construction program.

First, a 4.3-mile gravel access road and a "minimal" drilling pad would be built.

"Then one natural gas well would be drilled and tested," the EIS says. "If the results of this testing were unfavorable, all equipment and gravel would be removed and the affected areas would be restored to approximate preconstruction conditions. If the results of testing were favorable, the second stage would be constructed."

The second stage would involve expanding the pad for further drilling, and for production facilities. The pad would be 500 feet by 550 feet, with a working surface of about 6.5 acres.

NordAq also is proposing a 48-square-mile three-dimensional seismic survey, beginning in January with completion by April 30.

Five additional gas wells would be drilled, plus an industrial water well and a waste disposal well.

According to a schedule in the EIS, drilling of the initial test well would start in June, and first production from Shadura would begin in June 2014.

NordAq proposes to lay two buried gas gathering lines, each up to 8 inches in diameter. One would be the primary gas carrier; the other would be a backup and provide extra capacity, if needed. The lines would run roughly 4 miles from Shadura toward the Cook Inlet coast.

"Shadura gas will be sold directly into the pipeline that connects the Tyonek A platform from offshore to the LNG plant in Nikiski," the EIS says. The platform, pipeline and liquefied natural gas plant are ConocoPhillips properties.

Shadura would operate for about 30 years, the EIS says.

3-D seismic plans

The application for a right-of-way permit NordAq and CIRI filed in March said: "It is anticipated that the six natural gas wells will produce about 50 million cubic feet/day" for processing and delivery to the ConocoPhillips pipeline.

But Warthen, in his conversation with Petroleum News in March, said the 50 million cubic feet was the "facility design volume," that actual production could be less depending on the market for gas.

The EIS says full-field development of Shadura could include "the addition of one or two satellite drill sites," one to the north and one south.

NordAq also is proposing a 48-square-mile three-dimensional seismic survey, beginning in January with completion by April 30.

"The purpose of the survey is to image the sub-surface rock strata of the Shadura geologic discovery to help in planning for exploration and development," the EIS says. "The proposed survey area is located west of the Swanson River Oil and Gas Unit and east of the Cook Inlet coastline." ●

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EXPLORATION & PRODUCTION

Osprey platform well workovers continue

Cook Inlet Energy LLC is marching on with its efforts to revive damaged and shut-in wells on its Osprey platform in Alaska's Cook Inlet.

A Dec. 20 "operational update" from Cook Inlet Energy's parent company, Tennessee-based Miller Energy Resources Inc., said a workover of the RU-3 natural gas well was completed on Dec. 14.

"We then commenced swabbing operations to remove wellbore fluid in order to prepare for well testing," the update said. "During the workover we discovered multiple unreported fish left in the hole by a previous operator. We were able to successfully remove the obstructions, but this caused the workover to take longer than expected. The well has now been completed and the wellhead installed. The project is on track to be completed under budget."

The Osprey platform is in the Redoubt unit, on the western side of Cook Inlet. The platform was idle and its wells shut-in when Cook Inlet Energy acquired it out of a bankruptcy sale in late 2009.

Since then, the company has been working to restore production from the wells.

RU-3 a priority

Cook Inlet Energy made a priority of reviving the RU-3 gas well. The company hopes it will yield a secure supply of gas to run field operations, noting it had become increasingly difficult to secure gas for purchase in recent months.

The company noted its swabbing operations on RU-3 were recovering fluid at a slower rate than hoped. So it intends to conduct a "nitrogen coil cleanout" to speed up the process.

"Well testing will commence as soon as sufficient liquids have been removed from the wellbore," the operational update said.

In January, the company plans a gas workover on another Osprey well, RU-4. That well previously tested at a rate of 1.4 million cubic feet per day from the Tyonek gas sands, the update said. The workover is expected to take 10 to 12 days.

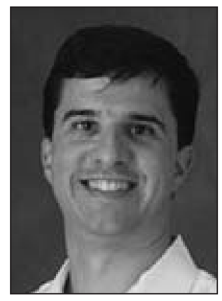
After completing work on RU-4, Cook Inlet Energy plans to either drill a sidetrack to the RU-2 well, or replace a failed electric submersible pump in the RU-7 well.

—WESLEY LOY

Petroleum news

Oil Patch Bits

Crowley's Otero now VP of Caribbean liner services



TONY OTERO

Crowley Maritime Corp. liner services division said Dec. 18 that Tony Otero has been named vice president of Caribbean services. He will remain domiciled in Crowley's Jacksonville headquarters, and will continue to report to John Hourihan, who was recently named senior vice president and general manager of the company's Puerto Rico and Caribbean services.

In his new role, which is currently held by Matt Jackson who will assume a new position on Crowley's petroleum services team Jan. 1, Otero will be responsible for the coordination of sales, marketing and operational shipping activities throughout Crowley's footprint in the Caribbean, which serves more than 24 islands, including the Bahamas, Trinidad, Barbados, Dominican Republic, Haiti, the U.S. Virgin Islands and many of the other Leeward Islands.

Otero, who is also a bilingual English-Spanish communicator, started his career as a senior accountant at Crowley in 1998 after working several years for accounting firm Deloitte & Touché. During his time at Crowley, he has held positions of increasing responsibility, including accounting manager, finance director, vice president finance and planning for the liner and logistics business units, and vice president of Dominican Republic and Haiti services. He is also a 2009 recipient of Crowley's highest honor, the Thomas Crowley Award. Otero earned his bachelor's degree in accounting and his master's degree in accounting from the University of Florida, and he is a certified public accountant.

Magnalight.com announces release of mini-tower light

COURTESY MAGNALIGHT

Larson Electronics' Magnalight.com said Dec. 18 that it has released a generator powered light tower designed to provide easy setup and mobility in a high powered stand alone package. The WAL-ML-2XM-3G mini light tower produces over 200,000 lumens of light output and can be extended to 12 feet in height, yet is small enough to be wheeled into various locations, deployed by one person, and provides standalone operation for six hours on a single tank of fuel.

The WAL-ML-2XM-3G mini light tower from Larson Electronics' Magnalight.com provides enough output to effectively illuminate large areas, yet can be set up by one person and operated independently of external power sources. Consisting of an adjustable mast that can be extended from 7 to 12 feet in height, two 1,000 watt metal

see **OIL PATCH BITS** page 13

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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LNG REROUTE

$100,000 a day, and longer, two-ocean trips mean more days at sea and more money out of someone's pocket. Further, most tankers already are locked in to fixed routes between a given liquefaction plant and given LNG buyers. Relatively few tankers are available to free-lance shipments.

But in recent years as the gas-price gaps between North America, Europe and Asia have widened, more LNG shipments are chasing price, with tankers diverted to higher-priced markets and spot sales becoming common.

Last year, the spot market comprised 25 percent of LNG transactions, up from 16 percent in 2006, according to the International Gas Union. Some see this as demonstration that in the right circumstances, the traditional industry model of Atlantic LNG for Atlantic buyers and Asian LNG for Asia isn't as rock solid as previously believed. The Panama Canal expansion might be timed just right.

CANAL DE PANAMÁ

The expansion of the Panama Canal (Third Set of Locks Project) will double the capacity of the Panama Canal by allowing more and larger ships to transit. The Panama Canal expansion should accommodate most of the world's superships when it opens in 2015.

LNG's two distinct regions

Most of the world's natural gas moves to market as vapor in pipelines. Last year only 10 percent of the gas consumed was superchilled into a liquid, loaded onto tankers and shipped to customers, according to the BP Statistical Review of World Energy.

But LNG is the fastest growing sector of natural gas trade. And most forecasts predict it will remain so.

Asia is the biggest LNG market and the one holding the strongest growth prospects, as China and India continue to build their economies.

Still, Europe, South America and North America are LNG consumers as well.

Over time, the industry split itself into two distinct regions, each serving its own geographic neighborhood: Atlantic Basin LNG makers served Europe and eastern North America, and Pacific-Australia makers supplied the Far East.

Until recently, LNG prices in the two regions were similar, and due to the high expense of moving LNG long distances there was little financial advantage in shipping LNG from one basin to the other. For example, in 2009 the LNG price averaged $9.06 per million Btu in Japan compared with a German imported-gas price of $8.52, according to the BP Statistical Review.

In 2010 and 2011, 76 percent of LNG made in Atlantic Basin plants was sold to Atlantic Basin countries, according to the International Group of Liquefied Natural Gas Importers. Atlantic Basin LNG makers are Algeria, Egypt, Libya, Nigeria, Equatorial Guinea, Norway and Trinidad and Tobago.

In those same two years, 98 percent of the Pacific-Australia LNG went to Asian buyers. These LNG makers are Australia, Indonesia, Malaysia, Brunei, Russia (Sakhalin), the United States (Alaska) and Peru.

Four Middle Eastern countries are swing producers, sending their LNG both east and west. Qatar, Oman, Yemen and the United Arab Emirates are located roughly equidistant from European markets via the Suez Canal and those in the Asia's Far East. They shipped about 60 percent of their LNG to Asia in 2010-2011.

In marketing and logistics, distance can explain a lot. The United States conducts far more international trade with Canada than with Australia — two countries of about equal population and area — because Canada is a lot closer.

So it goes with LNG.

It costs less than $1 per million Btu to ship LNG from Indonesia to Tokyo, according to recent figures from trade publication ICIS Heren. A like quantity from Australia to Tokyo costs about $1.22. (A million Btu is roughly 1,000 cubic feet after the methane is turned back into vapor.)

But shipping LNG from the Caribbean nation of Trinidad and Tobago to Tokyo costs about $4.16 per mmBtu, from Norway about $4.13, from North Africa about $3.26. The buyer, seller or broker eats the extra shipping cost when LNG travels long distances — a potent incentive to avoid that cost.

Hardly an international gas conference goes by these days without some discussion and speculation about what the expanded canal will mean for the industry's future.

Another disadvantage of long-distance LNG travel is that more ships are needed to deliver the same amount of gas, because each tanker's round-trip takes more time. LNG tankers aren't cheap. They cost roughly $200 million to $250 million each.

The industry generally expects the expanded Panama Canal will shave about $1 per mmBtu off the LNG shipping cost between the Atlantic and Pacific and cut days from the transit time between the two basins.

The Panama Canal Authority is still studying what toll it might charge LNG tankers to transit the canal, so the final figure could be higher or lower. Whatever the toll, the bigger canal will improve the economics for shipping LNG very long distances, creating incentive to exploit pricing differences between the Pacific and Atlantic. If enough LNG chases the highest price and supply and demand rebalance, the price gap should narrow, some in the industry predict.

Part 2 of this story will appear in the Jan. 6 issue of Petroleum News.

Editor's note: This is a reprint from the Office of the Federal Coordinator, Alaska Natural Gas Transportation Projects, online at www.arcticgas.gov/expanded-panama-canal-could-reroute-lng-industry.

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OIL PATCH BITS

halide lamps, and a 3000VA generator, this mini light tower is a complete lighting package. The tower and base assembly on this unit is constructed of heavy gauge steel that has been powder coated for high strength and resistance to rust and corrosion. The tower can be adjusted from 7 to 12 feet in height using an included hand winch, allowing operators to adjust the height to suit their particular needs and achieve full illumination of large work sites or outdoor events.

For more information visit www.magnalight.com.

Polyguard offers new pipeline protection

As reported on the Australian Pipeliner Website Dec. 16, the U.S-based Polyguard Products has been a manufacturer of buried pipeline coatings since 1950 and is now offering the RD-6 coating system to the Australasian market.

One of the company's most successful products has been the RD-6 buried pipeline coating system, which was launched in 1987. The RD-6 system has been used by a large sector of the United States oil and gas industry for over 25 years.

The product was initially used by customers for pipeline maintenance and rehabilitation; however, it is now also used widely for protection of girth welds on all new pipelines such as those installed throughout the massive shale oil and shale gas fields. Millions of square meters of pipeline have been coated throughout the world using the RD-6 system.

As a superior and differentiated tape system, the RD-6 offers excellent soil stress resistance, installs faster than most other coatings, is proven to be non-shielding to cathodic protection currents in case of disbondment and requires no cure.

RD-6 is a single-layer system, applied with a liquid primer. In very harsh applications an optional soil stress-resistant outer wrapping layer is also available. In accordance with the installation specifications the RD-6 is applied with a 25.4 mm overlap. The coating can be applied with or without initial preparation such as sand blasting and as a single-layer coating, and offers substantially higher production rates during application in the field.

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

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ARCHER RESPONDS

DROPS survey of the drilling derrick."

Buccaneer maintains its charge that Archer failed to uphold its end of the contract.

"Kenai Offshore has been continually forced to undertake unanticipated work and to contribute unanticipated expenses," Director Dean Gallegos said in a Dec. 21 statement. "Archer Drilling's failure to live up to its representations and contractual responsibilities under the (Master Service Agreement) seriously undermined Buccaneer's confidence in their ability to complete their work under the MSA and subsequently operate the Endeavour within the Cook Inlet while undertaking drilling operations, requiring the termination of Archer Drilling services and the identification of a replacement."

Underfunded "from the outset"

As a "relatively new player" embarking on "an entirely new business strategy" in the purchase of a jack-up rig, but investing "little of their own money in the project," Buccaneer and its affiliates needed a "very experienced operator" to oversee the project, and hired Archer in October 2011 to oversee the refurbishment of the rig at an Asian shipyard and to eventually operate the rig once it arrived in Alaska, according to the suit.

Through a joint venture with the Singapore-based Ezion Holdings Ltd. and the Alaska Industrial Development and Export Authority, Buccaneer formed Kenai Offshore Ventures to purchase the Transocean GSF Adriatic XI jack-up rig for $68.5 million.

Under the terms of the deal, Archer was not responsible for the condition of the rig at purchase, or for the work and equipment provided by third parties, according to Archer. To actually complete the work, Buccaneer hired the Singapore shipyard Keppel FELS.

Built in 1982, the Adriatic XI rig — renamed Endeavour-the Spirit of Independence — "had not worked in years" and was cold-stacked off the coast of Malaysia. "It was always clear that the Endeavour required a significant amount of work," Archer claimed. While saying Buccaneer budgeted $18 million to refurbish, winterize and move the rig, Archer believed the project required significantly more money. According to Archer, a new rig for Alaska would cost some $200 million, and transportation alone would cost $1 million.

According to Archer, this underfunding "from the outset" and subsequent "overdue invoices" caused delays by slowing down the deliveries of crucial parts. Because of late payment, Archer was forced to "stand down its workforce" and "vendors were unwilling to commence scopes of work or release equipment without these payments due to Defendants' payment track record and poor credit lines," Archer claimed in its lawsuit.

Moved the rig too soon?

As the delays continued and "millions of dollars" in unpaid bills piled up, Buccaneer wanted to move the rig to Alaska, according to Archer. "Despite the substantial amount of work needed to bring the Endeavour up to compliance levels, Defendants insisted that the Endeavour exit the Singapore shipyard in the hope of commencing drilling operations in Alaska prior to the work stoppage brought on by winter," Archer wrote in its suit.

While Buccaneer claimed the remaining work could be completed en route, Archer thought it would be "improper to conduct such 'hot-work' while in transit." According to Archer, Buccaneer moved the rig "knowing that there were not sufficient resources in Alaska, such as a shipyard, a labor force and a management agreement with Archer."

As a result, Archer claims, Buccaneer created a "logistical quagmire: more work needed to be done on the rig but they no longer had the resources or the manpower of a shipyard with which to complete it." To resolve this, Buccaneer told Archer to hire more than 70 workers, Archer claims. While these workers were being hired to eventually operate the rig, they would be asked to temporarily work to bring the rig up to code, Archer claims.

This work was "plainly outside the scope of existing work orders," Archer claims. While Archer expected to sign a management agreement for its role as operator, it claims Buccaneer failed to provide the document after "four months" and "several requests."

Meanwhile, Archer claims, Buccaneer kept hiring third parties and telling them to bill Archer for the work. While claiming Buccaneer failed to pay for its work requests, Archer said its own employees "have been fully paid by Archer throughout the project."

According to Archer, the two sides signed a memorandum of understanding in November 2012, resolving "all previously disputed invoices in a timely manner," but Buccaneer officials failed to show up to a scheduled meeting in Houston to conclude the process.

After "several attempts" to collect payment, Archer said it terminated the contract on Dec. 13, and notified local vendors and federal and local officials of its departure from the project. "The very next day, in an effort to avoid public embarrassment," Buccaneer publicly claimed that it had terminated the contract with Archer, according to Archer.

Buccaneer stands firm

While Buccaneer, through Kenai Offshore Ventures, admits it is "currently withholding payments" to Archer for disputed work, the company also claims it "has paid all undisputed amounts owed to Archer Driller and has done so within payment terms."

Additionally, Buccaneer said in its statement that it has contacted all the vendors that Archer hired to perform services on the rig "with the understanding that Kenai Offshore will review each of their cases and will step in and make payments for legitimate expenses associated with work performed by those contractors on the Endeavour."

The case is ongoing: "Buccaneer is currently reviewing the lawsuit lodged by Archer Drilling and believes that the allegations are entirely without merit," Gallegos wrote. "When served with the lawsuit, Buccaneer will respond fully, and such response will include its own claims for the damage caused by Archer Drilling's actions and inaction." ●

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NEW AGDC BILL

AGDC met the project requirement, but has been working with what it calls an optimized schedule and is now looking at first gas in 2019, rather than in 2015 as mandated in HB369.

A bill to expand AGDC's authority was introduced last year by House Speaker Mike Chenault, R-Nikiski, and championed by one of the co-sponsors, Rep. Mike Hawker, R-Anchorage. House Bill 9, 32 pages in length, passed the House in March of 2012, but failed to find traction in the Senate.

Chenault and Hawker told a Dec. 20 meeting of the Alaska Legislature's Joint In-State Gas Caucus that a bill based on HB9 would be pre-filed for the upcoming 2013 Legislature.

Hawker said the new bill, currently 42 pages in length, expands on HB9, and is intended to provide AGDC "with the greatest possible power to advance that in-state natural gas pipeline."

Statutory obligation

Hawker said the agency would continue to have the statutory obligation to get that natural gas to Alaskans at the least possible cost, and he said that if the project being worked by TransCanada and the North Slope majors under the Alaska Gasline Incentive Act, AGIA, or any other "purely private sector" line comes to fruition, "AGDC will be there able to play a role representing our interests."

If a private sector project doesn't come together, "we will be able to pursue a project that continues to meet the needs of the State of Alaska."

He said he and Chenault "believe in the private sector," but believe the state needs to provide "an environment and a catalyst that will move projects forward and should the private sector be unable or unwilling to perform, we have to look at getting natural gas into the hands of Alaskans as a public works project, just like highways, water and sewer systems. ..."

AGDC has "elevated the energy security for the state of Alaska to a priority state mission," Hawker said.

The new bill is based on HB9, he said, and is a project compatible with AGIA, not competitive.

If an AGIA project goes ahead, AGDC will give the state a seat at the table; if AGIA turns out to be a dead end, AGDC can "move Alaska's gas forward at the direction of the Legislature," Hawker said.

Significant change

Hawker said there is one significant change in the new legislation: It "will physically relocate the operations of AGDC as a corporate entity out of Alaska Housing Finance Corporation."

AGDC has been a subsidiary of AHFC, but he said it's time to "move AGDC into the big leagues," and the legislation would establish it as a standalone public corporation in the Department of Commerce and Economic Development. AGDC would, he said, exist much like the Alaska Railroad and AHFC exist, with AHFC's corporate statutes used as a template.

AGDC would have its own board of directors and the legislation proposes that the governor would appoint directors with "specific expertise in the things necessary to build, operate, manage pipeline and distribute natural gas."

As in HB9, ANGDA — the voter-created Alaska Natural Gas Development Authority — would be preserved as "a marketing entity for the state's gas," Hawker said. A pipeline builder has to be separate from a pipeline shipper and ANGDA would be able to act as an aggregator and marketer to help coordinate gas buys for Alaska communities and utilities who individually "may not have the wherewithal nor the, both the level of demand nor the economic ability to make 30-year long-term commitments," he said.

Hawker described the new bill has having "all of the provisions we had in the last House Bill 9 as well as some optimization" to provide statutory authority AGDC needs to move forward, including removing "some of the bureaucratic roadblocks" that AGDC faces.

The bill would allow AGDC to issue revenue bonds, project financing based on the merits of the project, and allow for confidentiality so that AGDC can exchange data with commercial entities and other state agencies.

Contract carrier

Hawker said there have been technical revisions and improvements to the section providing the regulatory framework for contract carriage, which would be a separate section within Regulatory Commission of Alaska statues so current RCA regulations and statutes won't be impacted.

The new section on contract carriage would be applicable to any project, not just AGDC.

And the legislation would make sure AGDC has "the statutory authority to conduct further build outs" and projects that would deliver gas to other areas of the state. This won't change what the Alaska Energy Authority or the Alaska Industrial Development and Export Authority do, he said, but would allow AGDC to facilitate pipelines throughout the state once the decision is made to do a project.

Funding

The maximum state investment in AGDC would be $400 million, Hawker

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FURIE FINE

domestic ports be done with U.S. ships.

CBP says Furie unlawfully used a foreign-flag, heavy-lift vessel in 2011 to haul the Spartan 151 rig part of the way from Texas to Alaska. Furie, headquartered in League City, Texas, is using the jack-up rig to explore for natural gas offshore in Cook Inlet.

Furie disputes the $15 million fine, calling it arbitrary and excessive, and is suing the government in federal court to try to nullify it.

Federal officials have asked the court to dismiss Furie's lawsuit. Assessment of the fine is not a "final agency action," and thus the suit is premature, the government argues. To collect, the government says it would have to sue in federal court, and so far it hasn't taken that step.

Furie's lawyers are trying to keep the company's suit alive, and on Dec. 17 filed an opposition to the government's motion to dismiss.

Furie argues the dispute already is ripe for court consideration, and the government to trying to get the suit tossed on a "technicality."

"CBP has issued its final decision, finding Furie's one-time movement of the rig from the Gulf of Mexico to Alaska a deliberate violation of the Jones Act, which merits the maximum penalty possible and likely the largest Jones Act penalty ever assessed," Furie said in court papers. "Furie has done everything in its power to convince CBP to remit or mitigate this draconian penalty. CBP has repeatedly stated in writing, however, that the administrative process is 'closed' and made clear that it now considers this a collection matter."

'Negative implications'

Kade's declaration was part of Furie's Dec. 17 court filing.

"The size of the fine and the uncertainty associated with the ultimate outcome of resolving the fine have resulted in substantial negative implications for potential lenders and investors," Kade said.

"This, in turn, affects Furie's ability to help address Alaska's severe energy shortage," Furie told the court.

One of Furie's arguments is that federal officials have been inconsistent. In 2006, Homeland Security granted a Jones Act waiver for use of a foreign ship to transport a rig. That effort to bring a rig to Alaska fell through. When Furie again sought a waiver in 2011, the department under a new secretary denied it.

Furie went ahead and used the foreign ship to transport the Spartan 151 rig around South America to Vancouver, British Columbia. It then used U.S. tugs to tow the rig the rest of the way to Alaska.

Furie says no suitable U.S. ships were available to carry the behemoth rig around South America, and that it had a "reasonable belief" the waiver ultimately would be granted.

The fine originally was imposed against Escopeta Oil Company LLC, which Furie acquired in 2011, before the rig arrived in Cook Inlet.

—WESLEY LOY

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NEW AGDC BILL

said.

There is $200 million which has been parked but must be re-appropriated for the project, he said. The governor has proposed $25 million in his budget, and about $100 million more is needed to bring the total to $400 million, including some $73 million previously committed.

Hawker compared this $400 million to the $500 million the state had put into AGIA.

The $400 million, he said is "money in the hands of a state agency that we can control that is accountable to us and ultimately to the people of Alaska," which he contrasted to the $500 million where there is "no accountability to the people of the state of Alaska."

—KRISTEN NELSON

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CHEVRON CONTROL

The arrival of Chevron is the most significant development yet on the Canadian LNG scene, introducing a global LNG player with several projects in the works, including Chevron's 69.14 percent interest in the Wheatstone project of northwestern Australia, its role in the Gorgon project in Western Australia and a 36.4 percent interest in a project in Angola.

Sollid said Kitimat will become part of Chevron's strategy to meet the projected growth in Asia's LNG demand, which is expected to double between now and 2025.

Apache calls it as milestone

Apache Chairman and Chief Executive Officer Steven Farris described the deal as a milestone.

"With experience developing LNG projects, marketing expertise and financial wherewithal, Chevron is the preferred co-venturer to join Kitimat LNG," he said.

Apache Canada spokesman Paul Wyke noted that Apache and Chevron "have a history of working together and are partners in the Wheatstone project," while Chevron has long-standing relationships in key Asian markets.

"Although we anticipate the momentum will accelerate with the new partnership, the partners will make a final invest decision (FID) after we achieve the remaining significant milestones of secure off-take contracts and completing front-end engineering and design," he told Petroleum News.

"We are undertaking early works to position the project for a shorter post-FID construction period," Wyke said.

None of the company officials was prepared to set a timetable for first LNG shipments, or confirm earlier forecasts of a startup in 2017.

However, the research and consulting firm of Wood Mackenzie said that "while efforts and decisions taken over the next two years will determine the winners and losers in Canadian LNG, the current slate of projects and promoters suggests the first (exports of) Western Canadian LNG is unlikely before 2019."

Strong multinational positions

What is clear from recent developments is that multinational companies are now strongly positioned to compete for market share.

They have made public their plans to pursue up to 75 million metric tons per year of exports, a large slice of the global supplies of 460 million metric tons in 2011.

The line-up for Canada includes Royal Dutch Shell (with Asian partners PetroChina, Mitsubishi and Korea Gas), BG Group, ExxonMobil, Malaysia's Petronas and now China's CNOOC, through its pending acquisition of Nexen, which has a major role in British Columbia's Horn River play.

British Columbia Energy Minister Rich Coleman said a company based in India he did not identify has "recently expressed interest, too."

He said the arrival of Chevron should have a revitalizing impact in a sector the British Columbia government believes could transform the province's economy by matching the energy output of the Alberta oil sands.

Premier Christy Clark said British Columbia could be enjoying the financial benefits of LNG 50 years from now provided it acts quickly before the opportunity evaporates.

Analyst: Moving 'the dream'

CIBC World Markets analyst Andrew Potter said in a note that Chevron "moves the dream of Western Canadian LNG exports closer to reality, which will bring some benefit to all Western Canadian gas producers."

Reynold Tetzlaff, an analyst with PricewaterhouseCoopers, said there is "no question" that Canada is in a race to Asia and "Australia is currently winning the race."

Ron Loberec, Deloitte's Canadian resources spokesman, echoed that view, forecasting that Australia will "make tens of billions of dollars out of its gas contracts."

Along with the change of Kitimat LNG ownership positions, Chevron will acquire a 50 percent interest in the Pacific Trail Pipeline, connecting the Spectra Energy pipeline from British Columbia's Horn River and Liard basins with a liquefaction plant and tanker terminal at the deepwater port of Kitimat on the northern British Columbia coast.

It will also gain 50 percent of 644,000 acres of petroleum and natural gas rights in the two basins, seen as the major supply source for Kitimat's planned two-train system to export 10 million metric tons a year of LNG.

Under the transaction, Chevron will acquire 110,000 net acres of the established Horn River play from the three former Kitimat partners and 212,000 net acres of Liard from Apache.

Financial details not released

Although the complete financial details were not released by the companies, the original cost of the project was set at $3 billion, since raised to $4.5 billion — a figure that is widely expected to be well short of the final mark.

Apache said it would sell its interest in the undeveloped Horn River and Liard acreage for $550 million.

It projected its own net proceeds at $400 million after paying Chevron to equalize interests in other Horn River properties it held in conjunction with Encana and EOG and to increase its ownership of the LNG plant and pipeline projects to 50 percent.

Long deemed the front-runner in the race to export LNG from Canada, Kitimat is armed with a 20-year export permit issued by Canada's National Energy Board. The only other export approval is for the BC LNG Export Co-operative, which is designed to export only 1.8 million metric tons a year.

Farris said the new ownership structure "will enable Apache to unlock the tremendous potential at Liard, one of the most prolific shale gas basins in North America."

Apache has estimated its Horn River and Liard resource potential at 50 trillion cubic feet and reported that test results from one of three wells at Liard averaged 30-day initial production of 21.3 million cubic feet per day or 3.6 million cubic feet per day from each of six fracture stages, placing ultimate recovery from the well of 18 billion cubic feet.

Encana still supports LNG

Encana Chief Executive Officer Randy Eresman said his company's major objective since joining Kitimat in March 2011 was to "ensure the progressing of this project towards its development."

Although Encana is no longer a direct participant "we continue to support LNG export as vital to diversifying markets for North American natural gas," he said.

Encana spokesman Jay Averill told the Calgary Herald that although his company gained useful experience being part of the project, LNG is "not our core business. Chevron knows how to build and operate one of these projects, as well as negotiate contracts. So we see this as a positive and logical next step for Kitimat."

Potter said the capital exposure for Encana "would have been too large; it makes sense for Encana to focus on shorter cycle time oil opportunities rather than long cycle time LNG." ●

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LEAN GAS

to be depressurized" for shipment to Fairbanks. The extracted NGLs would also have to be "reinjected back into the line and then brought down to Cook Inlet where there was going to be a natural gas liquid, or NGL, extraction facility," Richards said.

The straddle plant made the tariff higher for Fairbanks than for Anchorage, a feature of the 2011 plan which drew considerable objection from Fairbanks legislators.

'Awash' in NGLs

The facilities needed for NGLs are expensive, Richards said, that plan was based on "a market where natural gas liquids were at a premium," and that premium for NGLs was going to help reduce the cost of natural gas for citizens of the state.

"However, the world has changed in the last couple years," he said. "Now we see that the world is awash with natural gas liquids," because of Lower 48 shale gas production, and NGL prices "have softened considerably, down nearly 60 percent over the last couple of years."

There is "an NGL glut in the Lower 48," Daryl Kleppin, AGDC's commercial manager, told the caucus.

Kleppin said companies have been losing money on the NGL portion of their business, although petrochemical companies are benefitting from the NGL glut because they can make product from very low-priced feedstock.

Alaska's "problem is that we have to transport those components over 700 miles and pay the tariff on them and the tariff is, well in most cases would be higher than the end value of the product," he said.

Kleppin said that in conversations AGDC has had with potential shippers, "no one really had an interest in those components." And "it makes the project a lot simpler if you take those out."

Components no longer needed once NGLs are taken out of the plan include straddle plants for offtake along the line, the NGL extraction plant, a fractionation facility and intermediate compressor stations.

Entraining NGLs in the gas stream required a higher pressure.

"The higher pressure of 2,500 psi meant that we were not at industry standard piping, fittings and valves," Richards said. The "high-pressure pipe comes at an extreme premium" for the pipe, the fittings and the values, raising the cost of the project.

And the enriched gas stream, at higher pressure, meant fewer takeoff points because of the high cost of straddle plants, limiting "the amount of gas available to Alaskans along the route."

Evolution of project

Richards said the project evolved.

As AGDC looked at the engineering and economic aspects of the project, modifications were made to meet the charge AGDC had been given or providing natural gas in "the quickest possible timeframe, (at the) lowest possible cost to Alaskans."

With the elimination of NGLs, the pipeline size was increased to a 36-inch diameter and the pressure decreased to 1,480 psi, "industry standard for not only the pipe, but the valves."

The bill would allow AGDC to issue revenue bonds, project financing based on the merits of the project, and allow for confidentiality so that AGDC can exchange data with commercial entities and other state agencies.

The elimination of compressor stations along the line reduces the operating costs and the environmental footprint, he said.

Tariff drivers

With the changes in the project, including how the tariff is calculated, the projected tariff is lower, Kleppin said.

One change is that the tariffs are now calculated over a longer period, 30 years vs. 20 years in the 2011 plan.

Capital cost estimates have been updated and contingencies for different components have been adjusted, Kleppin said.

The key components of change are the lower operating pressure and the 36-inch diameter vs. the original 24 inches.

There is still a lot of engineering work required before costs can be finalized — and the requirements of shippers are not yet known, he said.

With the changes, the tariff is still within the original range for Anchorage, but the Fairbanks tariff "is significantly lower" with the main driver there elimination of the straddle plant, the cost of which was borne only by Fairbanks.

Cost at $7.7 billion

The current cost, on a plus or minus 30 percent basis, is $7.7 billion, compared to the $7.5 billion estimate in 2011.

"Inflation over the last year has added almost $200 million to the cost of the original concept, so $7.7 (billion) is essentially the cost estimate for both project," Richards said, with and without NGLs. Each year of project delay adds 2.5 percent to 3 percent inflation to the cost of the project.

The optimized plan has "less risk going forward" without the NGL component and the higher pressures in the line.

The cost to consumers at the burner tip for the optimized case is $9-$11.25 per million Btu in 2012 dollars in Anchorage and $8.25-$10 per million Btu in 2012 dollars in Fairbanks. That compares to the 2011 case of $9.63 per million Btu in Anchorage and $10.45 per million Btu in Fairbanks.

Contingent on funding

Richards said AGDC received $25 million in this year's capital budget and has "been able to continue some of the pipeline engineering work" and is initiating some of the facilities engineering work.

But staying on schedule, with an open season in 2014, a go/no-go decision in late 2015 and first gas in late 2019, "really depends on what we receive in funding and how much work we're able to do," he said.

If AGDC is again partially funded work would be done on advancing the pipeline and facilities, with limited field investigations.

"If we're fully funded then we will advance through what is known as the front-end loading 2 phase of our design for both pipelines and facility engineering to get us to that class 3 estimate for an open season," Richards said, with heavy engagement with regulators, including the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration, but also environmental regulators, followed by "a very extensive engineering field investigation program in 2013 to advance those projects."

The state's contribution, including some $73 million AGDC has already received, would total $400 million "to advance the project through to project sanction."

"That's getting through an open season, successfully acquiring shippers and purchasers of the gas, and then getting to a point of having to decide whether to go/no-go on the project to the next phase ... build out," Richards said.

For consumers

The optimized cost and tariff means that consumers in "Anchorage will see rates ranging from $9 to $11.25 per million Btu in 2012 dollars. That's comparable to what we're likely going to be paying in 2013, with the cost increases that we're hearing from our utilities," Richards said.

That compares to the 2011 base case, with NGLs, of $9.63, he said.

In Fairbanks, "the optimized case provides gas at $8.25 to $10 per million Btu as opposed to the $10.75 we were projecting last year," and compares to some $23 per million Btu Fairbanks is now paying, based on the cost of diesel for home heating.

"And then any community along the line that wants to tap in and have natural gas as an option for their home heating or power generation would see comparable rates available to them. And any resource developer that is looking to provide for jobs and resource extraction could gain access to reasonably priced gas," Richards said.

Confidentiality issue

Richards said many of the features of House Bill 9, which passed the House but got no traction in the Senate in the 2012 legislative session, "are still needed to be able to move this project forward."

We need sufficient funding, he said, and because AGDC lacks confidentiality abilities which were included in HB9, because "we are subject to the open records act, and then folks feel that they can't really share anything with us without it being flat open to the world."

Ownership of the line is also an issue that needs to be determined, he said.

AGDC is working to determine that the project would be economically viable, "but in the end there's going to have to be a builder-owner-operator and we need that ability to make that decision."

Regulatory Commission of Alaska statutes are also an issue, because they "currently don't cover contract carriage." The current law is common carriage, he said, which means anybody that wants to ship gas is granted access.

The challenge is illustrated by utilities, he said, who need to know that volumes they expect are available to meet their power load requirements. With common carriage, existing shippers would be forced to reduce their rates to accommodate the new shipper, and "the end user, the utility" would get less gas.

"Under contract carriage it is a contract between the shipper and the buyer of that gas" and the utility knows that they will receive that volume. ●

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