**Solidarity wavers**

Two Deh Cho First Nations ready to split, join Mackenzie Gas Project

By GARY PARK

C racks are appearing in the ranks of Deh Cho First Nations, with two of the 14 groups making up the umbrella organization ready to break away and join the Mackenzie Gas Project. The communities at Fort Liard and Fort Simpson in the Northwest Territories are indicating they are interested in joining the Aboriginal Pipeline Group which takes a one-third equity stake in the proposed Mackenzie gas pipeline.

Keyna Norwegian, chief of the Fort Simpson-based Liidlii Kue First Nation, told the Globe and Mail that her community wants a role in the Aboriginal Pipeline Group, adding “we are actively pursuing a lot of business.”

Meanwhile, former NWT Premier Jim Antoine has been hired by the Aboriginal Pipeline Group to see SOLIDARITY page 15

**Russia rejects all bids for $20B Sholokman project; gas to Europe, not U.S.**

By RAY TYSON

Russia has rejected assistance from some of the world’s most experienced offshore players, including U.S. majors ConocoPhillips and Chevron, to help develop its giant $20 billion Sholokman gas project on the Russian side of the Arctic Barents Sea.

More troubling for U.S. energy markets are reports that Russia has monopoly Gazprom now intends to use Sholokman gas exclusively to supply the North European Gas Pipeline to Europe, rather than liquefying it into LNG for export to America, as previously planned.

“The European market is … number one for Gazprom,” Gazprom chief executive Alexei Miller reportedly said in an Oct. 9 interview on the Russia Today television channel. A Gazprom spokesman later confirmed Miller’s television remarks, telling Reuter’s news service that Gazprom’s numerous delays in selecting partners for the project have only added to speculation that Gazprom is neither financially nor technically prepared to get involved in a $20 billion project, at least until natural gas prices reach much higher thresholds.

**Oil south of Walakpa?**

Conoco to drill south of gas field; USGS geologists say target could be oil

By KRISTEN NELSON

ConocoPhillips Alaska has applied for permits to drill exploration wells on Arctic Slope Regional Corp. land in the National Petroleum Reserve-Alaska south of Barrow and just south of the Walakpa gas field.

Neither ConocoPhillips nor ASRC would say what the objective is for the Intrepid wells, but U.S. Geological Survey scientists familiar with the area say the target could be oil — and the sands could be the same as the Brontosaurus well drilled to the south in the 1980s.

ConocoPhillips has applied to drill three wells, Intrepid 1, 2 and 3, during the winter drilling seasons between January 2007 and June 2011 using see WALAKPA page 19

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**Harnessing Knik Arm tidal power**

EPRI report looks at the feasibility and economics of harnessing the tidal currents between Cairn Point and Port MacKenzie in Southcentral Alaska. See story on page 9.

**Pioneer CEO confirms reduction in exploration spending; Auditor wants Alberta royalty shake-up**

**In a speech on Oct. 5 at the Independent Petroleum Association of America’s 2006 Oil and Gas Investment Symposium, Scott Sheffield, chairman and CEO of Pioneer Natural Resources, confirmed that his company has cut back on its capital expenditure on exploration. In March Pioneer reported a cut in exploration spending to reflect the company’s “commitment to significantly decrease its spending on higher-risk exploration.”**

“We’re cutting back exploration this year and going into the next four years,” Sheffield said at the IPAA symposium. Historical exploration spending in the range of 30 to 40 percent of total capital expenditure is being cut to 10 percent, he said.

But Sheffield also said that Pioneer will be investing in Mississippi and Alaska exploration. However, he said that total capex in 2007 will be 25 to 30 percent lower than the $1.4 billion in capex that Pioneer is spending in 2006. The 2007 will be 25 to 30 percent lower than the $1.4 billion in capex that Pioneer is spending in 2006. The Pakistan intends to use Shtokman gas exclusively to supply the North European Gas Pipeline to Europe, rather than liquefying it into LNG for export to America, as previously planned.

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**Alaska - Mackenzie Rig Report**

### Alaska Rig Status

**North Slope - Onshore**

- **Doyon Drilling**
  - **Dreco 1250 UE 14 (SCR/TD)**: Prudhoe XPad - X-08 workover (BP)
  - **Dreco 1000 UE 16 (SCR/TD)**: Workover C-07 (BP)
  - **Dreco D2000 UEBD 19 (SCR/TD)**: Alpine CD-4-321 (ConocoPhillips)
  - **OIME 2000 141 (SCR/TD)**: Kuparuk 1J-115 (ConocoPhillips)
  - **TSM 7000 Arctic Fox #1**

- **Sky Top Drilling**
  - **Dreco 1000 UE 2-ES E-11B**: BP

- **Mid-Continental**
  - **U36A 3-S 3A-01**: ConocoPhillips

- **Oilwell**
  - **700 E 4-ES (SCR)**: Milne Point F-78 (BP)
  - **2000 Hercules 14-E (SCR)**: Stacked at Cape Simpson (FEX)
  - **2000 Hercules 16-E (SCR)**: Under contract for drilling at Greyfriar Bay (Brooks Range Petroleum)

- **Emsco**
  - **Electro-hoist -2 18-E (SCR)**: Stacked, Deadhorse (Available)

- **OIME**
  - **1000 19-E (SCR)**: Stacked, Deadhorse (Available)

- **Nordic Calista Services**
  - **Superior 700 UE 1 (SCR/CTD)**: Prudhoe Bay (BP)

- **Nabors Alaska Drilling**
  - **Oilwell 2000 33-E**: Mobilizing (BP)

### Cook Inlet Basin - Onshore

- **Aurora Well Service**
  - **Franks 300 Srs. Explorer III AWS 1**: Demobilizing for stacking at Nikiski (Available)

- **Marathon Oil Co.**
  - **Oilfield 2000**: Mobilizing (BP)
  - **26**: Stacked (Available)

- **AKITA Equtak**
  - **Dreco 1250 UE 62 (SCR/TD)**: Stacked in Tuktoyaktuk, NT (EnCana)

### Cook Inlet Basin - Offshore

- **Unocal (Nabors Alaska Drilling labor contractor)**
  - **Not Available**

- **XTO Energy**
  - **National 110 C (TD)**

### Mackenzie Rig Status

- **Canadian Beaufort Sea**
  - **SSDC CAMMAR Island Rig #2 SDC**: Set down at Roland Bay (Devon ARL Corp.)

- **Mackenzie Delta-Onshore**
  - **AKITA Equtak**
    - **Dreco 1250 UE 62 (SCR/TD)**: Stacked in Tuktoyaktuk, NT (EmCana)

### Yukon Territories Rig Status

**Northwest Territories**

- **Ensign Resources Svcs. Gp.**
  - **Jackknife Double**: Racked in Ft. Nelson (Suncor)

- **AKITA/Kaska**
  - **National 80 UE**: Stacked in Fort Liard, NT (to drill in BC) (Suncor)

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The Alaska - Mackenzie Rig Report as of October 12, 2006. Active drilling companies only listed.

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

This rig report was prepared by Alan Bailey

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JUDY PATRICK

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**XTO ENERGY**

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Baker Hughes North America rotary rig counts*

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<th>Country</th>
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**Highest/Lowest**

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*Issued by Baker Hughes since 1944

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The Alaska - Mackenzie Rig Report is sponsored by:
Mackenzie costs likely next month

The updated price tag on the Mackenzie Project will likely be disclosed in November, consistent with a promise to release the figure in the final quarter, Imperial Oil Chief Executive Officer Tim Hearn said Oct. 11.

He told reporters in Calgary that Imperial and its partners are committed to making the project happen, "but time will tell whether it will go or not."

The latest cost estimate was C$7.5 billion, a figure that has since been overtaken by the cost inflation that is rampant in the Canadian oil and gas industry.

Some analysts have set new targets as high as C$10 billion, but Imperial has refused to speculate until it completes a re-evaluation.

The start-up date for a possible 1.2 billion cubic-feet-per-day of shipments from the Mackenzie Delta is also facing a delay of up to one year to 2012 because of extended deadlines for regulatory hearings. In the meantime, Imperial has postponed talks with the Canadian government on fiscal terms for the project. —GARY PARK

Weather hits Prudhoe Bay, Alaska pipeline

High winds on the North Slope and flooding near the Valdez end of the line pumped system; BP cleaning Prudhoe insulators

By DAN JOLING
Associated Press Writer

Both the nation’s largest oil field and the trans-Alaska oil pipeline were shut down Oct. 10 after poor weather at both ends of the 800-mile pipeline caused havoc.

BP said high winds were to blame for a power outage that shut down Prudhoe Bay in northern Alaska. Production fell to about 20,000 barrels Oct. 10, about 150,000 barrels were produced Oct. 9.

Flooding near the terminus of the pipeline, caused by heavy rain in Southcentral Alaska, is suspected of knocking out fiber-optic communication lines along the pipeline, said Mike Heawtoile, spokesman for Alyeska Pipeline Service Co.

Operators lost communications to remote valves that can be closed in the event of a spill.

Heawtoile said company protocol calls for the pipeline shutdown when valves cannot be closed from long distance. The valves can be staffed by crews that can manually operate the valves, he said.

At Prudhoe Bay, layers of dust and dirt blown by high winds built up on high-voltage insulators on power lines and the field, causing a short just before 3 a.m., said BP spokesman Daren Beaudo. “Several days of high winds followed with rain deposited mud on high-voltage insulators that are part of the Prudhoe Bay electrical power distribution system,” he said.

The mud caused two faults at Prudhoe Bay substations, knocking out power to field about 3 a.m. Oct. 10.

“The whole field came down,” Beaudo said.

The power station continued to operate, he said: “It’s the distribution system that had the problem.”

Winds were blowing about 12 mph at Deadhorse near the time of the outage, said Tom Dang of the National Weather Service. However, they were blowing significantly most of Oct. 9, with peak gusts of about 66 mph.

Pipeline communications critical

Communications are a critical operation for the trans-Alaska pipeline, which carries nearly 17 percent of the nation’s domestic oil supply daily.

“We lost communication with five of our remote gate valves just north of Valdez at about 4 a.m. Alaska time (Oct. 10),” Heawtoile said.

The remote valves are important when production facilities when the equipment is down. BP’s priorities for the pipeline shutdown when valves can’t be closed from long distance. The valves can’t be closed from long distance. The valves can be staffed by crews that can manually operate the valves, he said.

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“We lose communication, we shut the pipeline down,” he said.

 Flooding and mudslides along the Richardson Highway, which parallels the pipeline and is the only roadway out of Valdez, disrupted vehicle traffic. The Alaska Department of Transportation closed a 63- mile stretch of the highway, starting near Valdez.

The Weather Service said 6.5 inches of rain fell Oct. 8 and Oct. 9 at Valdez. Flooding in Keystone Canyon near Valdez hit four bridges hard and moved one 5 feet, said DOT spokeswoman Shannon McCarthy.

Instead of driving, Heartvale said, crews would be sent by helicopter to the remote valve sites. By midday Tuesday, crews had reached at least two valves and were in transit to others, he said.

Separate crews will seek the cause of the break in the fiber-optic line, Heawtoile said.

The company reported Oct. 10 that the line was restarted at 1:40 p.m. after technicians had reached the valve locations.

Alyeska said it would maintain 24-hour coverage at the valve sites until the pipeline is back to normal operations.

Flooding at terminal

High water along other roads in Valdez was hampering Alyeska’s ability to staff the Valdez Marine Terminal, where oil is loaded onto tankers. The terminal is across Port Valdez from the city and a road leading to it was affected by flooding.

Alyeska said it would limit the number of personnel required to report to work at the terminal until officials could verify the integrity of a bridge on the road.

Essential employees reported to work at the Valdez Harbor and were transported across Alyeska ports by boat. Nearly 500 Alyeska employees travel the road to work each day.

Prudhoe out for several days

Beaudo told Petroleum News Oct. 11 that BP expects it will be “several days” before production can be gradually restored to normal levels at Prudhoe Bay.

He said substations and high-voltage power systems are being systematically cleaned to clean the insulators. “Washing insulators on high-voltage systems requires specialized skills and equipment and will be done from the ground and from helicopters,” he said.

Power loads must be minimized by reducing equipment online until the insulation can be washed, and BP’s priorities for returning power are to support life systems in camps and facilities inhabited by workers, he said.

BP is continuing to produce small volumes of oil about 40,000 barrels per day, from Prudhoe Bay and “will ramp up production facilitites when the equipment is cleaned and the power supply is fully stabilized,” Beaudo said.

—Petroleum News contributed to this story
Evaluating a gigantic partnership

Jury out among analysts on whether Conoco/EnCana JV a deal or steal; Alberta premier’s likely successors ease tough talk on upgrading

By GARY PARK  
For Petroleum News

I t wasn’t a case of EnCana thumping its nose at Alberta’s current and future political leadership, but the big independ- ent’s precedent-setting decision to team up with ConocoPhillips in an inte- grated oil sands joint venture made non- sense of all the tough talk about forcing producers to upgrade their bitumen in the province.

Despite the insistence by outgoing Premier Ralph Klein and those vying for his job that more of the value-added bene- fits of upgrading and refining should remain in Alberta, EnCana and ConocoPhillips played the free market card in forging their US$26 billion partnership.

The pact will see the two companies operate on a 50-50 basis to achieve an eight-fold increase in oil sands production from 50,000 barrels per day to 400,000 bpd by 2015 at EnCana’s Foster Creek and Christina Lake leases (which have a total 44 billion barrels of bitumen in place).

In return for trading off 3 billion barrels of high-quality bitumen, EnCana will get an equal partnership in the Wood River, Ill., and Borger, Texas, refineries owned by ConocoPhillips, the No. 2 U.S. refiner.

The bitumen upgrading capacity at those plants will be boosted from 60,000 bpd to 275,000 bpd, with combined throughput of the two plants climbing to 600,000 bpd.

In addition to rolling assets worth US$15 billion into the bundle, the two companies are committed to spending US$5.5 billion each over the next two years to achieve their goals.

Deal or steal?

Since the unveiling of the plan, there has been a lot of flailing around among analysts over whether the transaction was a deal or a steal.

Ben Dell, with Sanford C. Bernstein in New York, said EnCana paid a “very high price” for what it gained, estimating the 3 billion barrels of bitumen in the ground were traded away for about $1 a barrel, about half the value of other recent trans- actions.

He also suggested that profit margins at refineries were high during the negotia- tions and have since collapsed.

Adam Zive, with Desjardins Securities, also agreed that EnCana will get a high premium for the transaction.

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PETROLEUM NEWS  •  WEEK OF OCTOBER 15, 2006

5
Governor creates new oversight agency

Lease Monitoring and Engineering Integrity Office will coordinate state, federal, local oversight of oil and gas infrastructure

By KRISTEN NELSON

Petroleum News

The state in instituting a cooperative that to ensure that doesn’t happen again. Facilities, Labor and Workforce Game, Transportation and Public

Murkowski signed an administrative order Oct. 6 creating a Lease Monitoring and Engineering Integrity Coordinating Office within the Department of Natural Resources.

LMEICO is charged with coordinating the oil infrastructure oversight efforts of a multitude of state, federal and local agencies stretching from the North Slope fields to the Alyeska Marine Terminal at Valdez. Administrative Order No. 229 says the office will be “the coordinator of state permits, authorizations and oversight of oil and gas leases designed to produce oil and natural gas from State of Alaska land.” The order “covers the permitting, authorization and increased oversight activities on all state oil and gas leases by the departments of Natural Resources, Environmental Conservation, Fish and Game, Transportation and Public Facilities, Labor and Workforce Development and Public Safety.”

Murkowski noted the two recent spills at the Prudhoe Bay field due to corroded transit lines at a press briefing and said that to ensure that doesn’t happen again the state in instituting a cooperative effort with the federal government and the North Slope Borough to improve oversight.

Murkowski reviewed federal government regulatory efforts and said the Alaska Department of Natural Resources would take the lead on the state’s regulatory efforts. The department is “initiating a comprehensive oversight program for all petroleum facilities and activities on state lands,” he said. LMEICO will be established in DNR’s Division of Oil and Gas and the coordinator will pursue memoranda of understanding with federal agencies similar to those which established the federal-state Joint Pipeline Office which oversees the trans-Alaska pipeline.

Similar to JPO

Natural Resources Commissioner Mike Menge, who has chaired an interagency team charged with responding to the recent pipeline problems, and who was the founding federal official at the federal-state Joint Pipeline Office in the 1980s, said the idea is for all state and federal agencies with regulatory authority to join in a cooperative manner. One of the issues, he said, is looking at who has authority where. From the North Slope to Valdez a number of state and federal agencies regulate the production and movement of oil.

The Alaska Oil and Gas Conservation Commission has control over the well bore down into the formation, he said, but the problems the state is encountering now are from the well bore to the common carrier line.

LMEICO will bring participants together to evaluate who has what authority and what authority is needed, and then to do “a systematic review of the infrastructure.”

The language in DNR’s oil and gas leases has very broad language covering what is required: “What we’re going to have to do is take that language and convert that into performance standards.”

There are two contracts on the street now: one to assist DNR and other agencies to compile performance standards. The second is to take a look at BP’s quality assurance program “to make sure that all of the internal processes that should be addressed are being addressed.” Any gaps found in that analysis will then be addressed, he said.

Starting at Prudhoe Bay

LMEICO will start at Prudhoe Bay but over time the program will be expanded to all oil and gas production in Alaska, phase two will be other North Slope infrastructure; phase three will be in Cook Inlet.

Murkowski said the operation would start small and will be expanded to meet needs as they are defined. The new Legislature will have to address the issue of funding for the new organization and in the interim participating agencies will provide personnel and funding.

Menge said LMEICO will perform risk assessments on all petroleum infrastructure on state leases, review all facility designs, operations and maintenance programs and practices for technical competency and consistency with established government and industry standards; and inspect pipelines and facilities on an ongoing basis to document compliance with approved procedures and plans.

The fundamental LMEICO goal would be “to ensure seamless regulatory oversight of oil and gas infrastructure and operations, from the reservoir far up to the loading facility to the pipeline technology team has been working on that, with the first conference, on maintenance pigging, set for Oct. 18. The goal is to look at tools that are used to control corrosion” on pipelines, and since pigging is one of the primary tools, the team decided that maintenance pigging conference will be a Nov. 13 conference on smart pigging conferences.

Fredriksson said other conferences will follow on other tools that need to prevent corrosion and monitor the integrity of pipelines.

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Canada more bearish than bullish

By GARY PARK
For Petroleum News

Canadian government low-balls oil sands volumes by 2020; concerned about rising consumption, increase in greenhouse gas emissions

I
n releasing the first long-term projec-
tion of energy supply and demand in
Canada since 1999, the Canadian gov-
ernment has taken some of the steam
out of forecasts for oil sands production.

Although emphasizing that its outlook
is not a prediction, just “one of many pos-
sible energy outcomes for Canada,”
Natural Resources Canada has suggested
that the gloomy report could harm
Canada’s reputation in the United States as
an ally that the U.S. view of Canada as an ally should not be under-
rated in a world where energy is a matter of national security and Canada is among
the few with the capacity to meet growing demands. Most of the others are in unsta-
ble, hostile or volatile regions, she said.

Because there are so few countries producing oil that can be trusted, Canada will
“always be a very, very important economy for the United States,” Cooper said.

Greenspan said industries and consumers worldwide are paying higher oil prices
because of the uncertainties created by political disruptions to crude supplies.

He said there is a “so-called terrorist premium, which is a fairly large number.”

On the pressures to reduce greenhouse gas emissions, he cautioned that imposing
limits on energy consumption will reduce the standard of living.

To that end, he argued that nuclear power must be considered to fuel the de-
velopment of Alberta’s oil sands to solve the “enormous” use of natural gas.

—GARY PARK

Newfoundland gas not expected to
reach market before 2020

In other conclusions, NRCan says:
• Saskatchewan’s crude oil production
will drop from 20,000 bpd (90 percent heavy) in 2004 to 327,000 bpd in 2020,

Natural Resources Canada has suggested oil sands production will
grow to 2.9 million barrels per day by 2020, well short of most
forecasts by governments and industry organizations.

resource potential is 2.7 million barrels
of heavy oil and 1.1 billion barrels of light.

The province’s gas production is forecast to plummet to 70 billion cubic feet per
year by 2020 from the current 261 bcf.

Natural Gas

British Columbia gas output will grow
modestly to 1.1 tcf in 2011, then ease off
to just under 1 tcf by 2020, although its share of natural production will grow to 19 per-
cent from 15 percent. That projection is
based on an ultimate gas potential of 50 tcf for B.C., but does not take into account 35 tcf of coalbed methane potential, which is scheduled to come on stream in 2007 and grow to 80 tcf in 2020.

Offshore Newfoundland oil produc-
tion is expected to drop to 134,000 bpd after 2007 from a peak of about 415,000 bpd, although NRCan is counting on the stalled Hebron/Ben Nevis development starting in 2011. Newfoundland’s several trillion cubic feet of discovered gas is not
expected to reach market before 2020.

The Sable offshore gas project in Nova Scotia should remain in the 150-210 bcf per year range through 2020.

Crude oil prices, in 2003 dollars, are forecast to decline to US$45 per barrel by
2010 and remain constant thereafter.

Petroleum Land Manager
State of Alaska

The Department of Natural Resources, Division of Oil and Gas is
seeking qualified, experienced applicants for a Petroleum Land
Manager to work in the Units Section. This is a permanent, full-
time, Range 26, exempt position. Starting salary will be $90,000 to $120,000
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This Petroleum Land Manager will lead a team of professionals to
evaluate options, formulate strategies, and recommend actions to
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cessful candidate will negotiate oil and gas unitization, par-
chondatory royalty agreements, and other complex agreements with
oil and gas lessees, the federal government, native corpora-
tions, and private individuals. In addition, the employee may par-
ticipate in various interdisciplinary teams to analyze and develop
ew commercial North Slope natural gas opportunities.

This position requires an appropriate college degree and experi-
ence in a field related to Petroleum Land Management, Petroleum
Engineering, Land Economics, Business Administration, or
Natural Resource Management. Five years experience in Alaska oil and gas
land related work or five years experience working in the upstream oil and gas industry in Alaska is
preferred. Applicants should have a thorough knowledge of oil and
and gas title issues, lease and unit agreements; possess excellent
negotiation and communication skills; show proven team
leadership and the ability to achieve results; and demonstrate the ability
to balance multiple tasks and responsibilities.

The State of Alaska is an equal opportunity employer and supports
workplace diversity. Individuals requiring accommodations may
call 800-587-0430 Voice or 800-770-8973 TTY/DD (Relay Alaska).
Submit a resume with a complete work history and a technical
writing sample by 4:00 p.m., October 20, 2006, either mail your
application materials to Sheila Westfall, Administrative Manager,
PO Box 550 West 7th Avenue, Suite 800, Anchorage, AK 99501-3560 or email to Sheila_Westfall@dnr.state.ak.us, in order to be
considered for this opening.
The participating areas include lands that ConocoPhillips has drilled or intends to drill and put into production or on injection within two years of the beginning of production from each participating area. The division said issues not addressed in the PA apply to only the top three priority well sites.

The Fiord Kuparuk PA includes all or portions of three State of Alaska leases, some 6,160 acres. The Fiord Nechelik PA includes all or portions of five State of Alaska leases and five leases that are held jointly by the state and the Nechelik reservoir (Kigak formation) are capable of producing or contributing to the production of hydrocarbons in paying quantities.

Production from long-reach horizontal wells

The Fiord participating area plans of development include a horizontal pattern miscible water-alternating gas recovery process. Five long-reach horizontal wells, three producers and two injectors, are planned from Colville Delta drill site 3 to develop the Kuparuk PA. Within the Kuparuk reservoir each well bore will be some 3,500 feet in length, and they will parallel each other some 4,500 feet apart. There will be 12 long-reach horizontal wells, six producers and six injectors, from CD3 to develop the Fiord Nechelik PA. Within the Nechelik reservoirs these well bores will parallel each other, each approximately 8,000 feet in length and spaced approximately 2,100 feet apart. Peak cummungled annual oil production from the two participating areas is estimated to be 20,000/24,000 barrels per day and ConocoPhillips told the division it expects to recover some 61 million barrels of oil from the two reservoirs over the 23-year project life.

Lease terms amended in Colville River unit agreement

The division said leases in the two Fiord participating areas are written on a variety of forms and during Colville River unit agreement negotiations, “the parties bargained for amendments to the terms and conditions of the leases to harmonize them. By amending, in the unit agreement, the terms of the older leases,” the division said the state “avoided costly and time-consuming re-litigation over problematic lease provisions in the older forms.”

Under the Colville River unit agreement the state’s royalty share of production from the two participating areas will be free and clear of all field costs incurred on the North Slope. The division said issues not addressed in the PA applications — methodology for allocating commingled fluid streams through the common Alpine processing facilities and a unit-wide gas management plan — were addressed in a CRU gas management agreement, effective July 1, 2006.

Expansion area lands agreement

The division’s 2002 second expansion decision for the Colville River unit required that the entirety of seven specific unit tracts be included in an approved Fiord PA within four years of the effective date of the expansion, but the participating area application did not include all seven of the required tracts and is modified by payments required in the PA agreement. The Colville River unit working interest owners (ConocoPhillips Alaska 78 percent and Anadarko Petroleum 22 percent) are required to make lease payments to retain the Fiord expansion area lands in the amount of $38,955.15 to the state and $15,897.14 to ASRC, by Aug. 1, 2006, and $81,418.27 to the state and $59,696.25, respectively, by Aug. 1, 2007. The division said the 2006 payment has been made and the 2007 payment is not subject to a provision allowing for voluntary contraction of the Fiord expansion area. In addition, the working interest owners will pay $25 per acre on Aug. 1, 2008, for each acre of Fiord expansion area land not included in a Fiord PA by that date; the payment will be $36 an acre on Aug. 1, 2009, 2010 and 2011, for each acre not included in a Fiord PA by those dates.

Fiord expansion land may be voluntarily contracted from the Colville River unit on a tract-by-tract basis, the division said.

The division has also approved a deferral, until Aug. 1, 2011, of the 10-year automatic contraction required under the Colville River unit agreement for the Fiord expansion area lands.

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Safety & environment

BLM employees honored for well cleanup

The U.S. Department of the Interior has given a National Environmental Achievement Award to the JW Dalton Legacy Well Cleanup Project Team, a group of 13 Bureau of Land Management employees, six of whom are stationed at the Fairbanks District Office, and a team manager; Stan Porhola, petroleum engineer; Tom Morris, environmental specialist and special projects manager; Greg Noble, petroleum engineer; Stan Porhola, petroleum engineer; Leslie Torrence, program analyst, and Wayne Svejnoha, environmental scientist. The Denver, Colo., employees are Tom Morris, environmental specialist and Elaine Flick, contracting officer. The award recognizes the team’s work in 2005 facilitating the emergency cleanup of the JW Dalton test well site in the National Petroleum Reserve-Alaska and preventing the contamination of the Beaufort Sea.

In 2004, accelerated erosion along the Beaufort Sea in northern Alaska cut about 300 feet of shoreline which put the JW Dalton well casing within 15 feet of the sea. The well’s reserve pit was partially breached. To prevent the release of contaminants into the sea due to additional shoreline erosion predicted in 2005, BLM secured emergency cleanup funds outside of its normal funding cycle and assembled a team of resource, contracting and field specialists to develop and implement an ambitious plan to remove potential environmental hazards from the site during the winter of 2005.

Starting in February and ending in May, 2005, the team worked with a contractor to haul more than 300 truck loads of reserve pit material four miles away to a secure storage location pending final disposal in a landfill. In addition, nearly 10,000 gallons of diesel fuel was removed from the well and the bore was plugged. Within six months of the cleanup, summer storms had washed the project site into the sea. The winter field work was complicated by the site’s remote location (more than 50 miles from the nearest community), no roads and temperatures averaging 30 degrees below zero. Heavy equipment for the cleanup was hauled overland during the winter and materials and equipment were delivered by air.

As a result of the cleanup, BLM initiated a systematic approach to inventory other old government drilled and abandoned well sites in NPR-A to determine if any other sites were endangered by shoreline erosion. Ten additional sites of concern were identified and BLM began a sampling program to characterize the reserve pit contents of the top three priority well sites.

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Tidal power from Knik Arm could be viable

EPRI report looks at the feasibility and economics of harnessing the tidal currents between Cairn Point and Port MacKenzie

By ALAN BAILEY

With concerns about the continuity and future pricing of natural gas supplies in Southcentral Alaska, could renewable energy sources such as wind or tidal power alleviate some of the region’s energy problems? Chugach Electric Association, for example, has investigated the possible development of a wind farm on Fire Island, adjacent to Anchorage International Airport.

In June the Electric Power Research Institute (commonly known as EPRI), a California-based non-profit research organization, published a detailed report on the feasibility of a tidal power plant in the Knik Arm, in the narrows between Cairn Point and Port MacKenzie. And in the Oct. 8 edition of Petroleum News we reported that Natural Currents Services LLC is investigating the construction of a tidal energy facility at that Knik Arm site — Natural Current Services is one of three companies interested in tidal power in the Cook Inlet area of Alaska.

In-stream energy

According to EPRI, existing operational tidal power plants such as a 340-megawatt plant in France depend on dams that impound the tidal water and then release the water through turbines. But for Knik Arm, EPRI envisions the use of a new technology that does not require a dam.

Instead, tidal in-stream energy conversion (or TISEC) devices would use the natural tidal current to drive turbines coupled to electrical generators. A typical tidal power plant would involve a farm of multiple, underwater TISEC’s. Depending on the TISEC design, each TISEC unit may be rigidly fixed in place under the water surface or it may float inside the water column, tethered by a cable attached to the sea floor.

TISEC technology is evolving through a pre-commercial research phase into the production of commercially available devices that should be capable of delivering electricity in quantities comparable to conventional electricity generation systems. And, alongside the evolution of TISEC technology, the science of free-flow tidal current power is also becoming established.

A key component of that science is an understanding of the total energy resource that may be available at a particular tidal energy site. That total energy consists of what is known as the power flux of the tidal current, integrated across the complete area of the site.

The power flux (generally reported in kilowatts per square meter) describes the amount of energy contained in the tidal current at a point in the site and is a function of the cube of the water velocity in the relationship to the cube of the water velocity makes the speed of the tidal current a critical factor in determining the available energy resource.

Knik Arm

Obtaining a high power flux requires both a large tidal range and some kind of channel that will cause a fast flowing tidal current. But the channel also needs to be large enough to provide a sufficient area of high power flux to build up a high total power output — “tiny channels with high power flux are of little use for tidal power generation since the overall tidal resource is quite small,” the EPRI report says.

The Knik Arm between Cairn Point and Port MacKenzie meets all of the essential requirements for a good site. The currents from the massive regional tides accelerate through the relatively narrow part of the arm at Cairn Point. And a deep channel provides a sizable area in which to deploy TISEC devices — the depth of the channel would also be critical in enabling adequate clearance between the devices and both surface ice and any shipping traffic in Knik Arm.

The report says that there is another deep channel with fairly high power flux west of the Port of Anchorage, but that channel lies under a major shipping lane and has limitations caused by winter sea ice. And, although the site northwest of Cairn Point seems suitable for tidal power, there are several issues that would need to be resolved. Those issues include avoidance of any impact on Beluga whales; dealing with large-scale eddies; and working and operating in very turbid water.

National Oceanic and Atmospheric Administration data for the Cairn Point site indicates a depth-averaged tidal current velocity of 1.1 meters per second, giving rise to a depth-averaged power flux of 1.8 kilowatts per square meter.

The EPRI report says that the total width of the Knik Arm at Cairn Point is 2,540 meters. The cross-sectional area of the deeper water within which the TISEC devices would be deployed is approximately 73,200 square meters. Multiplying power flux and channel size data results in a total channel power of 116 megawatts. But studies of tidal power implementation have established a rule of thumb that only about 15 percent of the total channel power can be converted to electricity without having a detrimental impact on the natural ecology of the site. That 15 percent factor results in an extractable power output of 17 megawatts for Knik Arm.

Could a tidal power plant of this size prove viable? The potential power output is quite modest when compared, for example, with the more than 350 megawatt power rating of the gas-fired Beluga power station on the west side of Cook Inlet.

From an economic perspective, the Knik Arm tidal power site has some factors in its favor. It lies next to an existing electrical infrastructure at Elmendorf Air Force Base and that, in turn, ties into the electrical grid in Anchorage. And the proximity of the Port of Anchorage would reduce construction costs.

However, the EPRI report says that the current 35-kilovolt line voltage available for the backhaul of power from the Elmendorf grid into the Anchorage grid is too low to support the maximum power output of a tidal power station in Knik Arm. So, the report says that an upgrade of the Elmendorf to Anchorage 57-kilovolt grid is necessary.

The report says that 15 percent of the total channel power can be converted to electricity without having a detrimental impact on the natural ecology of the site. That 15 percent factor results in an extractable power output of 17 megawatts for Knik Arm.

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line to 115 kilovolts would be necessary.

Two designs

The report describes two different Knik Arm power station designs, each involving a different type of TISEC device.

One type of device, known as the Lunar Energy Rotech Tidal Turbine, consists of a multi-blade propeller-style turbine inside a cylindrical duct. The complete structure would be installed on a concrete base on the sea floor. A commercial version of this type of device ought to be able to develop a maximum output of about 1 megawatt in the Knik Arm setting, according to the report.

The other type of device, known as a Marine Current Turbine Seagen free flow water generator, involves turbine blades attached to a pair of wings that extend horizontally from a vertical pile that is set into the seabed. In the Knik Arm each of these devices would likely produce a maximum output of 759 kilowatts.

Obtaining the 17-megawatt power output for a commercial operation from either TISEC design would clearly involve the installation of multiple devices. And the power station would require an armored subsea electrical cable to transmit the electrical power onshore.

Bringing the cable to a suitable onshore location might require directional drilling, the report says.

The EPRI analysts did a cost analysis of the use of Marine Current Turbines and determined that a full-scale power station would require 66 of these devices arranged in seven transects northwest of Cairn Point. The estimated cost of the complete installation, including the subsea cable and the onshore electrical connection, works out at about $109 million in 2005 dollars. And the annual operation, maintenance and insurance cost would be about $4 million.

The analysis assumed that the cost of any necessary power grid upgrades would be recovered from line usage charges.

The analysts then considered the economics of three different types of ownership for the power plant—a regulated utility, a municipality-owned utility and a private operator.

An electric utility can set electricity rates that cover operating costs plus some reasonable level of profit, the report said. Under that scenario the cost of electricity would work out at 9.2 cents per kilowatt-hour, using inflation-adjusted money.

A municipality-owned utility also needs to be able to recover its operating costs, but it can fund projects from tax-exempt bonds. Under that scenario the cost of electricity would be 7.1 cents per kilowatt-hour.

Both of these results assume the use of government renewable energy incentives of a type that is available for wind power.

Assessing the viability for a private operator is difficult because the assessment depends on determining a rate of return on capital, adequate to compensate for the inherent risks of the project and to cover the cost of the capital. However, the EPRI analysis indicated that the cost of electricity from a privately operated Knik Arm power plant would be higher than the average industrial wholesale electric rate from other sources (the analysis assumed a 2005 wholesale price of 8.6 cents per kilowatt hour, declining through 2011 and increasing thereafter). The inability to match that wholesale rate makes it impossible to calculate an internal rate of return for a privately operated plant, the report says.

But the report concludes that an in-stream tidal power plant may provide favorable economics for either a municipal utility or a utility generator, when compared with other locally available renewable energy production options.

“The in-stream tidal current energy shows significant promise for Knik Arm and represents a way to make sustainable use of a local renewable resource without the visual distractions that delay so many other energy projects,” the report says.

The EPRI report is available at www.epri.com/oceanenergy/streamenergy.html#reports.
Talking tough, but no big stick

Canada responds to oil & gas industry’s plea for ‘intensity-based’ greenhouse gas targets, tells private sector it will have to shoulder burden

By GARY PARK
For Petroleum News

The buzzword as Canadian Prime Minister Stephen Harper outlined the bare bones of his government’s major environmental initiative was “intensity,” which will resonate with the petroleum industry despite other warnings that the private sector will be forced to bear the cost of reducing greenhouse gas emissions and air pollutants.

In promising to introduce a Clean Air Act when Parliament reconvenes Oct. 16, Harper declared that the days of “voluntary compliance” are coming to an end and will give way to “strict enforcement” as Canada goes to work on cleaning up the atmosphere.

He said the government intends to lift from taxpayers the costs of paying for green initiatives such as the Kyoto Accord, which the government admits it is still legally obligated to enforce, while insisting that the targets are unattainable.

Flanked by four cabinet ministers, he said the new act — part of his pledge to introduce a “made-in-Canada” environmental program — will require a year of negotiations with industry and the provincial governments and could take four years to fully implement.

Although he would not set specific air pollution targets, Harper said industrial sectors will have to develop new technologies to pay for part of the cost of lowering harmful emissions.

“Massive reductions are possible by harnessing technology,” he said, adding that all sectors will be required to comply, including the oil and gas industry.

“The oil industry will be regulated,” Harper said. “If we are going to make significant progress (in reducing air pollutants) that will have to include specific progress in the oil sands themselves.”

The auto industry will also face “mandatory fuel economy regulation,” once its voluntary agreement with the federal government expires in 2010, he said.

That message came after a two-week buildup when Environment Minister Rona Ambrose told a Parliamentary committee that the oil and gas industry along with other large emitters of greenhouse gases were in for a tough time.

“At this point, it is time for us to stop politely asking industry to do the right thing,” she said.

Ambrose said legislation would give the government accountability through “increased auditing, increased reporting, increased monitoring ... to show progress both in the reduction of greenhouse gases, but also in addressing air pollution.”

—GARY PARK
see TOUGH page 12

Carbon trading needs ‘mandatory’ targets

The Montreal Exchange, the base for futures and options trading in Canada, can’t be faulted for its timing.

On the same day Canada’s Environment Commissioner Johanne Gelinas recommended the government include market-based greenhouse gas emissions trading as part of its plan, the exchange said a trading system could be up and running within a few months.

Exchange President Luc Bertrand said emissions-credit trading could be very good if other climate exchanges in the United States and Europe are any indication.

But the key for the planned Montreal Climate Exchange is whether the federal government’s plan, scheduled for release in October, includes hard caps on emissions, forcing companies to buy credits if they exceed those limits, or whether emissions will be cut voluntarily.

Bertrand said the ideal would be federally imposed mandatory levels of carbon dioxide emissions.

Canada is seen as a large market for credits, with about 800 million metric tons of the substance spewed out each year, enough to support an exchange in Bertrand’s view.

In Europe, where emissions reduction targets are legislated, credits trade at about C$18 per metric ton.

In the U.S., business is picking up at the Chicago Climate Exchange, which is partnering Montreal in launching the Montreal exchange. Membership has grown to 280 from 14 and the price of carbon has doubled to US$34 per metric ton over the last year.

Chicago exchange founder Richard Sandor said he expects the “commodification” of air and water will become “one of the great trends of the 21st Century.”

—GARY PARK

CAPP may have achieved one of five wishes

But the Canadian Association of Petroleum Producers may have achieved one of five key points on a wish list submitted to the government.

The industry’s leading lobby group insisted any targets for lowering greenhouse gas emissions should be intensity-based, which means the industry would have to cut emissions per unit of production, such as a barrel of oil or thousand cubic feet of gas.

—GARY PARK
see TOUGH page 12
Alyeska investigates pipeline vibrations

Sporadic vibrations at Isabel Pass in Alaska Range similar, but less frequent, to those the company studying at Atigun Pass

By RACHEL D’ORO
Associated Press Writer

The sharp reduction of crude flowing through the trans-Alaska oil pipeline after a partial shutdown of the nation’s largest oil field caused a steep section of the line to vibrate for weeks, the operator said Oct. 9.

The sporadic vibrations at Isabel Pass in the Alaska Range were prompted when daily North Slope production dipped below 600,000 barrels a day after the August shutdown of eastern Prudhoe Bay, said Mike Heatwole, a spokesman for Alyeska Pipeline Service Co. The pulsation in the line is caused when the reduced volume of crude rushes down a steep incline.

“The vibrations there were very minimal,” Heatwole said.

North Slope production is currently at 750,000 barrels a day, of which 350,000 barrels are from Prudhoe Bay. Heatwole said crews actively monitored Isabel Pass when the flow was below 600,000, and the last visual inspection Oct. 1 showed no activity.

“There does remain a potential for very infrequent and minor vibrations,” he said.

The eastern side of the gigantic field had been producing a daily average of 200,000 barrels until a leak and corrosion were found in a transit line that carries market ready oil to the 800-mile trans-Alaska pipeline.

The entire Prudhoe field, operated by BP PLC, normally produces up to 450,000 barrels of petroleum products a day, slightly more than half the North Slope production.

Vibrations nothing new

Heatwole said vibrations are nothing new as oil reserves diminish on the North Slope. They’ve been noted on steep descents of the 48-inch diameter pipe.

“It’s part of a condition called slackline, where the oil comes up and over the pass and the pipeline is not full at that junction,” he said. “As the oil goes down the pipe it speeds up a little. Vibrations are caused when this faster moving oil catches up with the oil” farther down the pipeline.

The problem was first noted in the mid-1990s when daily production fell below 1.4 million barrels. The vibrations were discovered at a section running through the

Tough

But following that path would not see the output of greenhouse gases in Canada decline.

In fact, the federal Environment Commissioner Johanne Gelinas said in late September that if oil sands production triples over the next decade, carbon emissions from the northern Alberta resource could double in the 2004-2015 period, wiping out any other national gains in lowering carbon emissions.

Even so, Harper appeared to side with CAPP in saying the government will “produce intensity-based targets over the short range and the long term and they will cover a range of emissions, not just carbon dioxide (seen as the leading contributor to climate change), but nitrous oxide, sulfur oxide, sulfur dioxide; so it will be a comprehensive plan.”

That was the first declaration from the Harper government that its environmental strategy would be intensity-based, which puts Canada at odds with its own Kyoto commitments that require a 6 percent cut in emissions from 1990 levels by 2012, although there are no penalties for those who fall short of the objective.

CAPP President Pierre Alvarez said intensity-based standards are vital for the oil sand gas sector that is “growing very, very quickly and that at each step is improving environmental performance.”

Environmental leaders brushed off that message, with John Bennett, executive director of the Climate Action Network, an umbrella group for 54 organizations, saying it is clear the Harper government is “postponing action on climate change and abandoning the Kyoto Protocol.”

Alvarez: government accepts role of technology

One of the world’s largest accounting firms says burying carbon dioxide will be an essential part of keeping greenhouse gas emissions, or GHGs, at safe levels as rapid economic growth takes hold in China, India, Brazil, Russia, Indonesia and other countries.

Known as carbon capture and storage or CCS, it is only now gaining attention as a possible answer to global warming.

John Hawksworth, the study author for PriceWaterhouseCoopers, said there is an urgent need to move CCS technology beyond the demonstration stage given that climate scientists have projected that even a 16 percent cut in GHGs by 2050 would not avert a 2-degree rise in average global temperatures.

But the challenge in selling CCS in Canada could stumble amid political footdragging, said ARC Energy Trust Chief Executive Officer John DuBeaut, one of the leading advocates of sequestering carbon dioxide to boost oil recovery from aging fields.

He said a blanket of “uncertainty” hangs over if and when projects will move ahead in Canada, despite promises four years ago to kick-start a carbon dioxide market.

In fact, The Financial Post recently quoted a former Alberta government must force industrial emitters to reduce their CO2 output, then ensure that the costs of collecting CO2 are not being passed directly to customers.

There is little chance of advanced CO2-enhanced oil recovery “unless there is some method of risk sharing,” he said.

But, for now the government has gone quiet, he said.

Former Alberta Energy Minister Murray Smith has repeatedly argued that CO2 injections could more than double the province’s oil production to date.

With that prize in mind, the Petroleum Technology Alliance of Canada formed a committee in 2004 to push the development of enhanced oil recovery technologies, specifically the use of CO2 as a recovery agent.

However, despite those efforts and a growing number of commercial and pilot projects in Western Canada there is still a feeling that the industry and government are reluctant to give their wholeheated support to carbon recovery until more conclusive results are available.

Carbon capture key to emissions fight

However, what the petroleum industry wanted to avoid was hard limits on greenhouse gas emissions resulting in a “growing economy being subject to real constraints,” Alvarez said.

He said the answer should be based on lowering the amount of energy used to produce a barrel of oil.

In addition to asking for intensity-based targets, CAPP also said the industry should not be treated any less fairly or any more onerously than any other sector; programs should reflect the importance of cost certainty; technology should be factored in as a critical component of any plan; and legislation should recognize that Canada’s natural resources are primarily owned by the provinces, creating a need for a harmonized federal/provincial program.

Stephen Hazell, executive director of the Sierra Club of Canada — part of the Climate Action Network coalition — said Canada needs immediate action, not “another long legislative process.”

The coalition had called for, among other measures, clear, measurable targets for reductions in greenhouse gas emissions; regulations on emissions by big industry; by 2008; auto emissions that copy the California standards; and plans to cut emissions from coal-fired power plants.

It has also demanded an end to what it views as CSI4 billion in annual subsidies, but CAPP rejects any suggestion that the National Energy Board, Canada’s federally financed national energy regulator, and certain programs administered by Natural Resources Canada amount to subsidies.

John Hawksworth, the study author for PriceWaterhouseCoopers, said there is an urgent need to move CCS technology beyond the demonstration stage given that climate scientists have projected that even a 16 percent cut in GHGs by 2050 would not avert a 2-degree rise in average global temperatures.

But the challenge in selling CCS in Canada could stumble amid political footdragging, said ARC Energy Trust Chief Executive Officer John DuBeaut, one of the leading advocates of sequestering carbon dioxide to boost oil recovery from aging fields.

He said a blanket of “uncertainty” hangs over if and when projects will move ahead in Canada, despite promises four years ago to kick-start a carbon dioxide market.

In fact, The Financial Post recently quoted a former Alberta government must force industrial emitters to reduce their CO2 output, then ensure that the costs of collecting CO2 are not being passed directly to customers.

There is little chance of advanced CO2-enhanced oil recovery “unless there is some method of risk sharing,” he said.

But, for now the government has gone quiet, he said.

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—GARY PARK

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12 PETROLEUM NEWS • WEEK OF OCTOBER 15, 2006
from the beginning of time it’s been confused with St. John’s, Newfoundland.

That could be a role reversal in the making for Saint John, New Brunswick.

It’s being touted by its own economic promoters as a new North American energy hub, which is only a partial overstate- ment if the projects now on the table make it through the approval and con- struction phases.

Until now, it’s too bad Saint John (metropolitan population about 120,000) has lived in the shadows of St. John’s (population about 170,000).

The privately held Irving family resources conglomerate has done what it could to put its New Brunswick base on the map, but that’s nothing alongside what it has in store.

Second refinery being studied

Irving Oil is just a few months away from completing a raft of studies that will determine whether it will proceed with a 300,000 barrel-per-day refinery — the first greenfield refinery in North America in a quarter century.

That coincides with the work already under way on Canada’s first liquefied nat- ural gas terminal — a partnership with Spain’s Repsol that should start regassify- ing 1 billion cubic feet per day of LNG imported by Repsol in 2009.

For about 46 years, Irving has operat- ed Canada’s largest refinery at Saint John, with crude capacity of 280,000 bpd and turning out 300,000 bpd of refined prod- ucts, exporting 175,000 bpd to the United States Northeast, including 500,000 bpd of reformulated gasoline. That volume represents 64 percent of Canada’s petro- leum exports and 19 percent of U.S. imports.

The company is now engaged in mar- ket and feasibility studies and searching for a partner — either on the supply side or as an equity stakeholder — to build a second refinery, doubling its output.

Uncharacteristic of Irving’s style, its new refinery plan was flushed out through media reports that it has acquired 3,000 acres near the established refinery, of which about 400 to 500 acres would be needed for a refinery.

Irving President Kenneth Irving said in a statement that the plan is an “attrac- tive investment for companies to respond to the call for more North American refin- ing capacity.”

Refinery cost pegged at C$5-C$7 billion

Although the details are sketchy, Irving said the refinery could take “sever- al years” to build at a cost of C$5 billion to C$7 billion.

It is basing its case for an expanded role in the volatile refining sector on an argument that more than half of the U.S. Northeast’s refined products come from the Gulf of Mexico, which it notes is vul- nerable to storm-related disruptions.

Saint John, it says, has an ice-free deepwater port that offers safe, reliable and secure supplies to ease the vulnera- bility of the Northeast to short-term and spot-market arrangements.

There were cautionary notes from ana- lysts.

Michael Ervin, president of energy consultant M.I. Ervin & Associates told Petroleum News that although many pro- posals for new or expanded refineries “never see the light of day” Irving has a track record of delivering.

He also said the desire by Irving to open a new refinery illustrated the com- pany’s apparent belief that it “feels the risks are tolerable and manageable.”

However, Ervin said there are signifi- cant potential risks, such as predicting market conditions several years away, or the prospect that governments might impose expensive changes to the way gasoline is formulated.

To that end, he said it is important for Irving to find a partner to share the capi- tal costs and financial gamble.

Two smaller operations would be challenged

If the project does get a green light it poses a challenge for two smaller oper- ations in Newfoundland.

In August, Harvest Energy Trust pulled off a surprise when it acquired North Atlantic Refining’s Come By.

The small Atlantic Canada city bids to become a N.A. energy hub, with plans for a 2nd refinery, work under way on LNG terminal

It’s Saint John and don’t forget it

Small Atlantic Canada city bids to become a N.A. energy hub, with plans for a 2nd refinery, work under way on LNG terminal

continued from page 12

VIBRATIONS

Chugach Range at Thompson Pass, the steepest drop in the entire line. In response, Alyeska installed a system that essentially slowed the rate of flow in that section, mim- icking a full line, Heatwole said.

When production dipped below 1 mil- lion barrels in recent years, the vibrations began occurring in the second steepest sec- tion, at Atigun Pass in the Brooks Range. Heatwole said Alyeska began actively mon- itoring a 360-foot section there last year and pipeline engineers are analyzing data to determine a fix, such as a system like the one employed at Thompson Pass.

Vibrations were among concerns Alyeska immediately addressed when BP first announced it planned to shut down all of Prudhoe Bay while it corrected the pipeline corrosion.

BP ultimately decided to keep the west- ern side of the field open and in late September restarted partial production on the eastern side. By that time, Alyeska already had considered the impact a greatly reduced flow would have on mechanics of the pipeline as well as on the crude, which moves more slowly in smaller quantities, dropping in temperature and leaving a paraffin buildup.

“We always knew there would be reduced throughput long term,” Heatwole said. “The shutdown announcement accel- erated a lot of our thinking, but we’re not starting at ground zero.”

Isabel Pass vibrations less frequent than at Atigun Pass

The vibrations at Atigun Pass have jossed the line as much as a half inch, but clos- er to a quarter inch on average, he said. The effect was similar at Isabel Pass, but occurred less frequently.

There’s no risk for damaging pipeline supports and beams, according to Heatwole. The pipeline was designed to absorb energy and move under conditions including earth- quakes.

“It’s important to stress that this is some- thing our engineering stuff was well-aware of and predicted,” Heatwole said. “There’s no immediate threat to the line. It’s a long- term challenge.”

PIPELINES & DOWNSTREAM

It’s Saint John and don’t forget it

Small Atlantic Canada city bids to become a N.A. energy hub, with plans for a 2nd refinery, work under way on LNG terminal

By GARY PARK

PIPELINES & DOWNSTREAM

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FINANCE & ECONOMY

OPEC to cut production 1M barrels per day

OPEC has agreed to trim global oil production by 1 million barrels a day to boost prices, and its members were discussing how to share the cut, the cartel’s president said Oct. 11.

“...the cut itself is agreed,” said Nigerian oil minister and OPEC president Edmund Daukoru.

Oil prices barely changed after his comments.

Daukoru told reporters after a Cabinet meeting in the Nigerian capital that the cuts would begin at the end of October and said members of the producing cartel were “nearing consensus” on how to share the cuts.

Daukoru’s comments followed a slew of reports attributed to anonymous sources from member countries who said the cartel plans to trim its daily production of 28 mil- lion barrels by 1 million barrels.

Some analysts had been skeptical that members of the Organization of Petroleum Exporting Countries were willing to voluntarily sell less oil right now — especially its largest producer, Saudi Arabia — given that prices are twice as high as they were three years ago even after a recent 25 percent decline.

OPEC is not scheduled to meet until December, though Daukoru had said earlier in October that the cartel was considering holding an emergency meeting before then to discuss what to do about falling prices.

The last time OPEC trimmed its output — by 1 million barrels a day — was December 2004 when oil traded slightly above $40 a barrel.

Oil prices have fallen sharply in recent weeks from their mid-July high of $78.40 on the New York Mercantile Exchange. By the afternoon of Oct. 11 in Europe, light, sweet crude for November delivery was up 2 cents to $58.54 a barrel and Brent crude was down 5 cents to $59.29 on the ICE Futures exchange in London.

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SAINT JOHN
Two ANS gas nightmares: LNG, coal

ConocoPhillips' chief economist, Marianne Kah, sees gas line threat from two directions: plentiful LNG, switch to coal

By KRISTEN NELSON
Petroleum News

There is a window for Alaska North Slope natural gas and Marianne Kah, ConocoPhillips' Houston-based chief economist, has both supply and demand nightmares about how it could close: ANS gas could lose the market to a plentiful supply of liquefied natural gas from abroad; or it could lose the market to demand destruction caused by utilities in the Lower 48 building coal-burning plants.

Kah told the International Association for Energy Economists in Anchorage Oct. 10 that she also sees a purely Alaskan threat: the gas reserves' tax initiative on the November ballot which would slam a $1 billion a year tax on North Slope natural gas in the Prudhoe Bay and Point Thomson fields, delaying the gas pipeline and also putting a damper on investment in the state.

Natural gas prices

Kah said that over the course of 12 months natural gas prices have been at $15 and at $4, and when the price was $15, the forward-looking price was $11. That forward curve was inflated by financial investors, she said, but why is the price dropping?

Inventories are high right now, and "there is still concern that we will reach storage capacity," she said, if the winter is warm. If inventories fill up, prices could drop lower, she said, using the United Kingdom as an example. The UK gas market had been extremely tight, but after the Langede pipeline came on from the North Sea at the beginning of October "gas prices went negative" and gas had to be shut in because storage was full and there was no place to put the gas, Kah said.

"So we have seen the ugliness of what could happen with too much supply and we just hope that doesn't happen in the U.S.," although several companies have shut in U.S. gas production because costs are so high.

Domestic gas production is flat, not declining — partly because of production returning after the hurricanes — but Kah said it also shows "we are getting a much bigger supply response at these higher prices we've seen than I expected ... a higher supply response than a lot of people thought was possible in the Lower 48, which worries me long term."

Department of Energy forecasts for domestic and Lower 48 production show that new gas supplies will be needed, which is why ConocoPhillips is interested in utilizing a gas pipeline from the Alaska North Slope, she said.

The 20 years of gas bubble is gone; it went away in the mid-2000s; and with combined cycle power technology the power sector is using more natural gas and the gas-intensive portion of the industrial sector, fertilizer and aluminum, is being driven out of the U.S. "They just simply can't be here. They were developed here at $2 to $3 gas environment and really can't live in an environment of gas prices above that. And they will move to places like Trinidad that have stranded gas and will not remain in the United States," she said.

Growth in electric power sector

Kah said the electric power sector is where there is likely to be the most domestic growth in natural gas use.

"And I would say for the next five years that demand growth is built-in: we don't have to work for that. That new power plants have already been built and they've been running at 25-40 percent utilization rates ... and we'll probably run those power plants at higher capacity rates before anyone will build new power plants."

Kah said she is "very worried" about what happens in 2010-12.

"If people don't see our pipeline coming to the Alaska North Slope, they will build coal plants and they will build nuclear plants and at any price that gas demand won't be there," she said.

The power companies need to see that the gas pipeline is coming, "they need to believe the project's real, they need to believe it's going to happen or we will see that demand disappear."

The U.S. Department of Energy has forecast that coal will go to gain share in the power sector, from 50 percent to 57 percent, she said. Natural gas is projected to lose share, dropping from 19 percent to 17 percent. DOE is also projecting that natural gas will lose share in the industrial sector, fertilizer and aluminum, but Kah said she thinks the incentives for nuclear in the Energy Policy Act of 2005 will help that industry grow.

"So I worry about nuclear taking share away from gas."

"But my biggest worry is coal-fired power plants, because right now, utilities are trying to decide what to build going forward."

The Midwest and other regions are going to have to decide over the next five or 10 years what kind of power plants to build "and they're going to go for coal if they don't see that pipeline coming."

"If people think it's going to be a coker unit to process heavier crude."

Harvest Vice President Jacob Roorda told Petroleum News the trust believes having a refinery is running and making cash gives it a "huge advantage" over proponents of several million barrels of new refining capacity now under consideration.

"But I don't believe the project's real, they don't see that pipeline coming."

Alaska production is a huge part of the potential growth for U.S. natural gas, but "if we don't get that Alaskan production, we will have lower demand growth," she said, stressing that "an issue is how we make the investment. We could make the investment (in the gas pipeline) and lose the market if we're not careful and I spend a lot of my time talking to utilities, trying to tell them that the pipeline is coming."

LNG supply likely to grow

Kah said there is a lot of confusion about LNG, but through 2010 the supply is "extremely short. There really are no extra cargos," and what few extra cargos there are, are taken by regulated utilities in Texas and Florida that can roll the price into average costs.

"But post 2010 ... there is a big potential for LNG," she said.

"What we have seen so far is evidence of oversupply, but that will change."

"And what we expect to see is gas-to-gas competition taking place then as LNG projects compete to get into the market and compete for long-term contracts."

"That's my second nightmare ... the first is coal plants, second is LNG."

"ConocoPhillips is ready to go with an Alaska gas project, she said, but there will be a new Legislature and a new governor, who may "want to start from scratch" and set the project back to the beginning."

Then, she said, there is the gas reserves initiative on the November ballot, "and probably the biggest thing worrying me today is the gas reserves tax." Kah said ConocoPhillips believes the tax will interfere with and delay the gas pipeline project.

Cyclical oil price issues

Kah talked about factors affecting oil prices and said that she believes oil price is "in a cyclical downturn" but also believes "that we are in a higher-price environment than we were back in the '90s when we were used to a $20-a-barrel long-term equilibrium price."

"So why are prices dropping? The U.S. economy is slowing. Demand growth is also slowing, partly as a result of the economy and also because of "price-related demand destruction."

see NIGHTMARES page 15

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MARIANNE KAH

PETROLEUM NEWS • WEEK OF OCTOBER 15, 2006
NATURAL GAS

SAINT JOHN
Chance plant from Swiss-based Vitalo.

The refinery currently processes 115,000 bpd of mostly sour feedstock from the Middle East, Russia and Latin America and has indicated it is considering a coker unit to process heavier crude.

Harvest Vice President Jacob Roorda told Petroleum News the trust believes having a refinery is running and making cash gives it a "huge advantage" over proponents of several million barrels of new refining capacity now under consideration.

"But we can't control the competition," he said. "We'll just take our chances."
Agrrium has no plans to shut down Kenai plant

Company expected an extended shutdown this winter due to seasonally higher demand for home heating

The facility, which is located at tidewater on the east side of the Cook Inlet on the Kenai Peninsula, ships anhydrous ammonia and urea to many parts of the world including South Korea, Mexico and Taiwan.

The facility is capable of producing 640,000 tonnes of urea and 280,000 tonnes of ammonia annually.

One hundred and fifty people are employed at Agrrium’s Kenai Peninsula nitrogen facility.

In August press release Agrrium said, the Alaska “facility is expected to operate at about 75 percent of capacity over the next 12 months, operating one ammonia and one urea plant.”

The high prices have also been due to a change in the financial markets, with more money going into commodities — and now backing out with the slowing economy.

Kah added the high prices are due to things like high activity levels. Revenues are higher, so companies are spending more money “and the service industry just can’t keep pace with us. They can’t add rigs fast enough,” which is forcing up costs.

And then there is staffing: “what we’re all finding is you can’t find the people,” Kah predicted that labor issues will last longer than equipment issues, even though “the equipment issues are severe.”

Demand from China is a factor driving prices. The oil industry doesn’t drive steel, Kah said “2007 is a particularly problematic year” for prices, with “considerable downside risk.” She also said she expects “prices to continue to cycle down between now and 2010.”

One hundred and fifty people are employed at Agrium’s Kenai Peninsula nitrogen facility.

But, despite unanimous backing among Deh Cho leaders for the offering, there are no takers.

One industry source told Petroleum News that until Deh Cho land claims and self-government claims are settled “we have no desire to gamble in an uncertain environment.”

Harry Deneron, chief of Fort Liard’s Acho Dene Koe, the driving force among Deh Cho leaders for the offering, said the Canadian government to issue the Deh Cho land claim is “time for Deh Cho leaders to join the discussion of the land claim settlement.”

Some observers believe the price of holding out against the Mackenzie proj-
cet was mirrored in the refusal by explo-
rion and production companies to answer an offering of gas exploration

Agrrium told its suppliers Oct. 12 that it was shutting down its Alaska nitro-
gen plant from Nov. 1 to March 1. But company spokeswoman Lisa Parker said the company has no plans to shut down this winter.

Agrrium said in an Aug. 23 press release that it had successfully obtained sufficient natural gas supplies to allow for the opera-
tion of its fertilizer facility in 2007, but that it expected the plant to “experience an extended shutdown during the winter months due to seasonally higher demand for home heating.”
## Companies involved in Alaska and northern Canada’s oil and gas industry

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

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**Northwest Technical Services**

Northwest Technical Services, NWTS, provides top-quality administrative, professional, technical and craft personnel to clients throughout Alaska. Serving the oil industry since 1980, NWTS and its competent staff strive to place the right person in the right job at the right time. The key is knowing their contractors’ needs and seeking a proper fit for the job. Prior to joining NWTS, Debby Frisby worked seven years with the temporary agency MILA Inc., which NWTS purchased. She has specialized in recruiting for technical and craft positions with NWTS for the past 10 years. Debby came to Alaska in 1986 with her husband, Mario. After he retired from the military, they chose to stay. Their “children” are Xena, the Rottweiler and Leslie a Shih Tzu.

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Debby Frisby, Personnel Specialist
Gazprom had indeed dropped the U.S. gas market and also decided to go it alone on Shтокман field development. “It is the final decision,” he said. In addition to ConocoPhillips and Chevron, Gazprom's so-called “shortlist” of contenders for the Shтокман project had included Norway's Statoil and Norsk Hydro and France's Total.

**Russia moving to regain control of resources**

The Shтокман decision appears to be Russia's latest maneuver to establish itself as a global leader in energy and to regain control of the nation's oil and gas resources, as recently demonstrated by Russia's obvious attempts to redo contract terms for two mega-projects offshore Sakhalin Island operated by world energy titans ExxonMobil and Royal Dutch Shell.

For months, Gazprom had led the Shтокман bidders and the world press to believe it would select a partner or partners to help it develop the field and its mouth-watering 110 trillion cubic feet of estimated natural gas reserves. In September 2005, Gazprom even issued a press release saying it was “resolving to select two or three companies that will form a consortium for the Shтокман project implementation.”

However, Gazprom kept postponing its self-imposed deadline, but did say in September 2006, a year after the initial pledge, that it was still analyzing proposals from all five international majors. And just two weeks ago Gazprom said it would not amend the shortlist of contenders for Shтокман and definitely planned to announce the winners by the end of this year.

**U.S. had been targeted for LNG from Shтокман**

Gazprom targeted LNG-hungry America early on as the primary recipient of Shтокман gas. But that was before U.S.-Russia relations began to sour earlier this year over several hot political issues, including Russia's bid to become a member of the World Trade Organization. There were even allegations that Russia was using Shтокман as a bargaining chip to gain U.S. access in the World Trade Organization, you said.

In early May, U.S. Vice President Dick Cheney touched off another ruckus when he told Baltic and Black Sea leaders that Russia was using its massive oil and gas reserves to blackmail neighboring countries. Russia was widely criticized earlier when it briefly halted gas exports to Ukraine in a price dispute that also disrupted supplies to Europe. Moscow also warned Europe that Gazprom might divert supplies to Asia, if it was barred from the European market.

Gazprom insists that Cheney's harsh remarks about Russia would not influence its decision in choosing partners for the Shтокман project. However, just three weeks ago, Russia President Vladimir Putin said that Russia was thinking of ratcheting up to half the gas from Shтокман to Europe and away from the United States. Analysts said later that was bad news for U.S. bidders Chevron and ConocoPhillips. In fact, it turned out to be bad news for all the Shтокман bidders.

Responding to the world energy stage with a lot of clout, already claiming to be the world's largest gas company focusing on geological exploration, production, transmission, storage, processing and marketing of gas and other hydrocarbons, Gazprom, 50.002 percent owned by the Russian government, also claims to have the world’s largest natural gas reserves. Its share in the global and Russian gas stocks makes up 17 percent and 60 percent, respectively, with overall reserves estimated at 291 trillion cubic meters and currently priced at US$138.6 billion. In 2005, the growth of Gazprom’s explored gas resources substantially outpaced the fast rate of gas extraction and accounted for 583.4 billion cubic meters. Gazprom says it also provides about 20 percent and 90 percent of the global and Russian gas production, respectively. In 2005, the Gazprom Group of companies extracted 547.9 billion cubic meters, which was 2.8 billion cubic meters above 2004 production.

Thus far, Gazprom has provided little explanation regarding its decision to dump the U.S. LNG market, or why it decided to pursue Shтокман development on its own.

Despite the company's enormous size, a project on the order of Shтокман typically would require at least several deep-pocket companies to share development costs. Moreover, Gazprom does not appear to have the experience or expertise to tackle such a risky project on its own. A logical choice for a Shтокман partner would have been Statoil, which operates the huge Snohvit gas development in the Norwegian sector of the Barents Sea.

Statoil decision “not expected”

Gazprom's decision to go it alone on Shтокман development “was not expected,” Statoil said in a prepared statement. “We will now discuss the implications of the announcement with Gazprom,” Statoil said. “We are confident that Statoil is a good partner for Russia in realizing the Barents Sea potential. Statoil is still committed to a long-term presence in Russia and will continue to pursue business opportunities there.”

However, Statoil made it clear May 23 in comments before the UBS Global Oil & Gas Conference in Texas that the company was in no rush to join the Shтокман project. “I would say that Shтокман is not something we have to do, but very interesting because of the size,” Geir Bjonstad, Statoil's vice-president of investor relations, said at the UBS conference. Shтокман bidders and U.S. hopefuls Chevron and ConocoPhillips had not responded to Gazprom's go-it-alone decision as of Oct. 13.

Earlier this year, Jeff Lowe, vice president in charge of ConocoPhillips' commercial division, said, “We think we provide a lot of technical expertise both on the upstream and the liquefaction side” of the Shтокман project. ConocoPhillips holds a stake in Lukoil, Russia's largest oil producer.

Under Gazprom's original plan, which required major LNG facilities on both sides of the ocean and tankers to transport the product to U.S. markets, Gazprom was looking at a 2011-2015 startup, with some analysts forecasting startup as late as 2020.

The Shтокман project already had been on the table for more than a decade. Gazprom's numerous delays in selecting partners for the project have only added to speculation that Gazprom is neither financially nor technically prepared to get involved in a $20 billion project, at least until natural gas prices reach much higher thresholds.

Russia at odds with Exxon, Shell over Sakhalin

On other fronts, Russia's resources ministry reportedly told Exxon in September that it would not agree to enlarge the license territory of its Sakhalin-1 block despite discovery of new reserves close to or at existing deposits. The ministry said its representatives had told the U.S.-based major they would auction the newly discovered deposits.

Russia's sudden change of heart on Sakhalin-I came just weeks after first oil from the Exxon-operated project began flowing on time with peak rates of 250,000 barrels per day expected by year-end. An outraged Exxon warned Russia to honor its decade-old production-sharing agreement to develop the oil and gas block, or risk spooking other foreign investors in the country.

The Russian government, citing damage to salmon-bearing rivers on Sakhalin Island, also withdrew environmental approval for the Shell-operated Sakhalin-II liquefied natural gas project. The decision came amid a tense business dispute between Shell and Russia's Gazprom, which was trying to join the consortium that Shell controls.

Industry analysts said the environmental ruling looked like an attempt by the Russian government to renegotiate terms or force Shell to concede to Gazprom's demands in the $20 billion production sharing deal, rather than close it down on environmental grounds.

The complex development straddles the coastline on the northern rim of the island, with offshore platforms, a liquefied natural gas plant and hundreds of miles of pipeline snaking toward an ice-free port in the south. Russia's coastal cities are home to salmon-bearing rivers and excessive logging along a pipeline route. Shell denied that it had violated any Russian environmental laws.

“Although there have been various environmental challenges on this project, these have been tackled and largely overcome,” Shell said in a statement released in Moscow. “All concerns are being addressed expeditiously in cooperation with the relevant authorities and do not constitute any legal grounds for nullification.”

However, an amendment of the approval “could be damaging for the project and for Russia,” the Shell statement warned. Shell owns 55 percent of the Sakhalin-II project, followed by Japan's Mitsui with 25 percent and Japan's Mitsubishi with 20 percent.
EIA: natural gas to average $7.53 in ’07

Henry Hub spot price expected to average $6.90 per mcf this year; WTI, $67 per barrel in ’06, $66 per barrel next year

By KRISTEN NELSON Petroleum News

The Henry Hub spot price for natural gas is expected to average $6.90 per thousand cubic feet this year and rise to $7.53 per mcf in 2007, the Department of Energy’s Energy Information Administration said Oct. 10 in its short-term forecast.

EIA said it projects actual Organization of Petroleum Exporting Countries production cuts will be less than stated because such cuts are prorated and some OPEC members are already below existing quotas due to production difficulties.

The agency is projecting an increase in world oil demand in 2007, which is expected to result in an increase in demand for OPEC oil, keeping 2007 OPEC crude oil production at current levels.

“Surplus world crude oil production capacity, all of which is located in Saudi Arabia, is expected to increase only slightly in 2007,” the agency said, keeping surplus world oil production capacity near 30-year lows.

The increasing demand will be partially met by new supplies from non-OPEC sources, with net annual non-OPEC oil production expected to grow by 700,000 barrels per day this year.

World petroleum consumption is expected to grow by 1.2 million bpd this year and by 1.5 million bpd in 2007. There is not expected to be any U.S. growth this year; demand growth in 2007 is expected to be 400,000 bpd, with the United States and China accounting for over half of worldwide demand growth next year.

EIA said because of limited surplus production capacity and a continued tight supply-demand balance the agency said it “projects that world oil prices in 2007, on average, will be only slightly less than their average 2006 levels.”

EIA expected West Texas Intermediate crude oil to average almost $67 this year and almost $66 in 2007.

EIA said domestic dry natural gas production is expected to increase by 0.8 percent both this year and next “due in large part to restored production capacity” after hurricanes in the Gulf of Mexico in 2005.

Total net imports of natural gas, pipeline and liquefied natural gas, are expected to show a 4.5 percent decline this year due to a decrease in the amount of Canadian natural gas available for export to the United States.

Total LNG imports for 2006 are expected to be approximately 650 billion cubic feet compared to 630 bcf in 2005.

2007 LNG imports are projected to total 920 bcf, the EIA said. The 41 percent increase in LNG imports next year is largely due to rising incremental supplies from Africa-Algeria, Nigeria, Libya and Egypt, the agency said.

The Henry Hub natural gas price, which was close to $14 per mcf in October 2005, following the hurricanes, is expected to average about $6.90 per mcf this year and $7.53 per mcf in 2007.

Natural gas prices are expected to be “significantly lower” this winter than last, the agency said, due to production recovery after the hurricanes and “the very high levels of natural gas storage.”

continued from page 1

INSIDER

the company is focusing its Alaska resources on the development of its Oooguruk field in the shallow waters of the Beaufort Sea northwest of the Kuparuk River unit. The company is also investigating the Cape York oil field off shore the southwest coast of the Kenai Peninsula.

Sheffield confirmed that the company is focusing ahead with the Oooguruk development, with first production slated for early 2008. She’s “a lot of additional running room... in adjacent opportunities to continue to toe in,” he added.

And Sheffield quoted some economic data that seems to confirm that an independent oil company can make a decent return from a medium-sized Beaufort Sea development.

The projected internal rate of return for Oooguruk is 40 percent, with a discounted return on investment of 1.8, Sheffield said. According to Pioneer’s data the company’s fields in the Lower 48 have internal rates of return in the range 35 to 45 percent.

—ALAN BALEY

Auditor wants Alberta royalty shake-up

THE ALBERTA GOVERNMENT’S Auditor General Fred Dunn says people are getting sick because of the province’s lax food safety inspections in restaurants. But Albertans will be just as sick to hear Dunn’s statement that the province is losing out on oil and gas royalties, perhaps to the tune of C$180 million to C$200 million a year.

“Alberta is not getting its royalties which the regime says it should be collecting,” he told reporters.

“We’re missing money” because of an inability to know the “completeness and accuracy” of well production data, Dunn said.

He calculated that the rate of errors on the costing side amounts to 2.4 percent, with the government swallowing most of the mistakes.

Energy Minister Greg Melchin acknowledged Dunn’s concerns, but argued there was nofootprint accounting system.

However, he agreed to respond to the auditor general’s recommendations.

The industry is largely responsible for its own reporting, making it difficult for the government to calculate oil and gas volumes back to the well head.

Dunn called for an overhaul of those accounting methods, saying that until the government can accurately pinpoint the source and quantity of the production it can’t accurately assess the royalties owing.

A spokesman for the Canadian Association of Petroleum Producers told the Calgary Herald that the books are left behind the government swallowing most of the mistakes.

Dunn also again raised concerns about Alberta’s shrinking royalty take, which averaged 19 percent over the last three years compared with the government’s tar-

Can you see the light?

THERE ARE LOTS OF LITTLE BUMPS on the Yellowstone Brick Road to energy independence. Some of them may just be crunchy fluorescent light bulbs.

The Energy Department, the Environmental Protection Agency, and even the Department of Housing and Urban Development have lined up behind the government’s annual PR effort to get people to switch to compact fluorescent light bulbs.

Here’s what the Oct. 4 press release has to say:

“The Department of Energy encourages all Americans to answer the president’s call to be more energy efficient,” Energy Secretary Samuel Bodman said.

“Taking small and easy steps, such as replacing light bulbs with newer, more efficient compact fluorescent bulbs, can add up to real, substantive savings.”

As you might suspect, the rub is that it all depends on the old saw: “If everybody just...”

And what PR writer could resist the phrase of the day – “Change A Light, Change the World.”

Well, maybe just a little. For compact fluorescent, the mes-

age from the EPA is that one bulb change by every American household would save enough electricity to light 2.5 million homes, and save $30 each for those who did the changing.

Then again, in a nation of nearly 300 million souls, you could bury a Hummer in pennies if everybody just sent in one red cent for the project. And you could cover that mammal a few feet deep with the envelopes the pennies were mailed in.

Like modern diamonds, the twirly fluorescents of today are a lot better than the clunky models of a few years ago, and they do deserve a look.

The old fluorescents put out a weak, green-tinted flicker, while many of the new ones provide a nice white light, especially with the shiny silver reflectors that are cropping up in hotels and other commercial applications.

Fluorescents do cost a lot less to operate. A 20-watt model puts out the same amount of light as a 75-watt standard bulb. And there’s a bonus in some climates — a lot less excess heat that has to be whisked away by air conditioning. And there are no worries with the curly-fry bulbs. They remain or twenty times more expensive, and many of them fall by the wayside long before the label’s “life of lighting bliss promised on the label.”

Another thing that the EPA might like to consider: The bulbs really aren’t supposed to go in the trash, since they contain toxic chemicals. And few communities have systems for easily recycling the bulbs.

Still, if you’re busy brewing your sawgrass into ethanol, be sure to use compact fluorescents so you can see the mash properly.

Just don’t ask how many energy secre-

aries it takes to change a light bulb.

—ALLEN BAKER

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the Kuukpik No. 5 drilling rig.

Mobilization would begin this year as soon as weather permits and drilling of the first well is planned for Jan. 18-Feb. 6, with a second well possible Feb. 6-May 5. The winter route to the well sites would include approximately 30 miles of ice road from proposed staging areas. “If constructed, the ice road system will begin from the nearest gravel road system south of Barrow and continue south to the Intrepid exploration well locations,” the company said.

The proposed Intrepid well sites are on oil and gas leases co-owned by ConocoPhillips Alaska, Pioneer Natural Resources Alaska and Anadarko Petroleum; ConocoPhillips will operate the wells.

The company said production tests may be performed after production casing is set; any oil would be held in tanks and re-injected or hauled to existing North Slope facilities; produced gas would be flared.

**Gas going to Barrow now**

Gas is being produced from north and northeast of the proposed Intrepid wells, with the Walakpa and South Barrow fields providing natural gas to Barrow.

Natural gas production from the South Barrow field began in 1958 and from East Barrow in 1981. The Walakpa field, discovered in the 1980s, was developed in the 1990s.

The most recent production posted by the Alaska Oil and Gas Conservation Commission, for August, shows one producing completion at the South Barrow gas field, with August production of 4.7 million cubic feet, and nine producing completions at the Walakpa field, with August production at 77.8 million cubic feet.

Production from the South Barrow field peaked in 1980 at 1.027 billion cubic feet per year, the East Barrow field peaked at 583 million cubic feet a year in 1991 and that Walakpa peaked at 1.388 bcf per year in 2000, according to Alaska Division of Oil and Gas records.

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From exploration wells, although oil shows are also common, “there is a general consensus that the Barrow region is more gas-prone than oil-prone, due to the regional geologic parameters that influence whether oil or gas may occur — including presence of appropriate source rock and thermal maturity — suggest the area should be oil-prone. Yet, gas is the most common hydrocarbon recovered from exploration wells, although oil shows are also common,” he said.

**Houseknecht said conventional wisdom about the area holds that gas migrated north from the “deeper Colville trough, relatively late in basin history, and this gas may have displaced oil that may have accumulated earlier.” The Lower Cretaceous Unconformity, the LCU, is the commonly suggested migration path, he said.**

Houseknecht disagrees with the interpretation of the sandstone reservoir at Walakpa as Kernik sandstone or Kuparuk-C. He said “there are a number of unconformities that converge in this part of the stratigraphic section and some geologists (including me) have suggested that the reservoir at Walakpa is an older sandstone within the upper Kenaiq Shale (Miluweach and Kuparuk A-B).”

“Bottom line: there are multiple potential reservoir sandstones in the Upper Jurassic to Lower Cretaceous part of the stratigraphic section and these reservoirs are likely lenticular in nature — not present in a blanket over the entire area.”

Houseknecht said there may be additional reservoirs in the overlying Brookian section, including Torok formation turbidite sandstones and Namushuk formation marine to nonmarine sandstones. There may also be deeper reservoirs, below the Upper Jurassic, such as the Sag River or Ivvuk formations. Those, he said, would probably be secondary objectives, if they are even being considered.

**Looking for the oil leg?**

As to what ConocoPhillips is planning to test, Houseknecht said while “the proposed wells south of Walakpa could be gas tests, it is more likely they are intended to test the idea that the Walakpa gas accumulation may represent a gas cap above an oil leg.”

He said the “Brontosaurus well, drilled about 15 or 20 miles south of Walakpa by ARCO in 1985, encountered a 50-foot thick sandstone at a stratigraphic position similar to that of the gas-bearing sandstone in Walakpa.” Bird said he recalls that the Brontosaurus sandstone was “water-wet.”

“The optimistic view would hold that the Walakpa gas sand and the Brontosaurus sand are the same sand body, thus showing that it extends at least 20 miles north to south.”

The Intrepid wells are proposed for section 6, township 19 north, range 19 west, Umurak Meridian and sections 11 and 22 of T19N-R20W, UM. T19N-R20W, UM. Brontosaurus was drilled in section 6 of T18N-R20W, UM. T18N-R20W, UM. It reached a total depth of 6,660 feet.
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