Hovering over Northstar

BP tests Crowley hovercraft at offshore Northstar field

BP is testing a new hovercraft at its Northstar oil field offshore Alaska’s North Slope about 12 miles northwest of Prudhoe Bay. BP Exploration (Alaska) spokesman Daren Beudo told Petroleum News June 11 that BP has entered into a five-year lease agreement with Crowley Marine to test the new hovercraft, with the first year considered a trial period meant to test the craft’s performance in all conditions that present themselves over the course of the year.

The hovercraft design comes from Griffon Hovercraft, a British firm. It was manufactured for Crowley in the United States by Kuchiak Marine in Seattle and will be used for ferrying personnel and cargo to and from Northstar, Beudo said. The dimensions of the vehicle are: 12 meters long with a mass of 2,700 kilograms. It is allowed affordable access to it.

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Opportunity beckons

Turnabout: Faced with fish decline, Bristol Bay Natives look to oil

By STEVE SUTHERLIN
Petroleum News Associate Editor

I n a dramatic turnabout, Alaska’s Bristol Bay Natives have endorsed the idea of oil development in the Bristol Bay Region. Bristol Bay has long been thought to hold commercial quantities of oil and gas, but oil development in the bay had been on hold due in large part to a reluctance of fishing-dependent local residents to support oil exploration on a large scale.

In the bay — a 180-mile wide (at the mouth) by 250-mile crook north of where the Alaska Peninsula joins the west coast of Alaska — prolific salmon resources have historically been the primary economic driver. The area also has fisheries for pollock, cod, halibut, sole, crab and other species.

Today, however, the fishing industry in Bristol Bay is on the ropes, and oil development is looking much more attractive as a vehicle for future prosperity in the region. The Bristol Bay Native Corp. has rallied local support to assure the oil industry that the region is open for business.

“There is widespread to almost unanimous support for on shore, and mixed support for offshore drilling.”

see INSIDER page 2

Washington in crisis mode

Greenspan: Tight supplies could weaken industries; expect $7.50 gas

By GARY PARK
Petroleum News Calgary Correspondent

W ith U.S. natural gas supplies at levels so low they may not be able to meet demand during a summer heat wave, and no prospect of a sudden turnaround in domestic production, the alarm bells are sounding in Washington.

For those who missed his initial warning in late May, Federal Reserve Chairman Alan Greenspan said June 10 that the United States is “not apt to return to earlier periods of relative abundance and low prices any time soon,” adding that market signals point to wholesale gas prices greater than $7.50 per thousand cubic feet by next January.

He told the House Energy and Commerce Committee that high prices stemming from the supply-demand crunch have “put significant segments of the North American gas-using industry in a weakened competitive position” against their global competitors.

“Unless this competitive weakness is addressed, new investment in these technologies will flag,” Greenspan said, without going as far as to suggest.

B.C. launches bold campaign

British Columbia’s new slogan: ‘we’re $17 billion closer than Alaska’

By DON WHITLEY
Petroleum News Contributing Writer

O ffering a catchy slogan of “we’re $17 billion closer than Alaska,” Canada’s western-most province of British Columbia has launched a campaign designed to convince the oil patch, and U.S. consumers, that the province’s oil and gas potential is huge.

The “$17 billion closer” refers to the estimated cost of the Alaska Highway Natural Gas Pipeline, and almost matches the amount of capital ($25 million) the province wants to see invested in exploration and development over the next 10 years.

Having played second fiddle to Alberta for the last 50 years, British Columbia is now looking forward to the day when — for natural gas at least — it might become a serious challenger to that dominance.

The campaign got a tremendous boost last week when a parade of U.S. and Canadian energy executives and government officials testified in Washington, D.C.,
Redoubt production impacted by water

By KAY CASHMAN
Petroleum News Publisher & Managing Editor

O il production from Forest Oil’s Redoubt Shale field in Alaska’s Cook Inlet is slowly dropping off and will continue to do so until more wells are brought on line and secondary recovery with water flood comes on line in 2004.

Tanker delays at Drift River where oil is loaded for shipment was one of the first problems faced by Forest at the offshore field, which started up Dec. 9 and is thought to hold more than 100 million barrels of recoverable oil. That challenge has been partly alleviated and company officials think it can be further addressed during contract negotiations, but another factor has cropped up, impacting oil production.

Water problem unusual

The oil reservoir is producing unexpectedly large amounts of water. Gary Carlson, Forest Oil’s senior vice president for Alaska, told Petroleum News June 6.

He said Redoubt production from four wells in the Hemlock participating area “with certain amounts of down time” has dropped from about 4,000 barrels a day in April to an “average of about 3,500 barrels of oil a day” in early June. It is currently producing “just under 3,000 barrels of water per day.”

Production will “continue to slow down off until we can get more wells on. Water flood will also bring that up,” Carlson said.

“It’s currently producing ‘just under 3,000 barrels of water per day,’” he continued. “That’s unusual. Usually you would find a common oil-water interface that would be consistent across the field,” he said.

“Three of the wells produced some water initially. Even the best well, Redoubt No. 2, which produces 1,100 to 1,200 barrels per day, produces 200 gallons of water per day. … You wouldn’t tell from the logs. It was unexpected,” Carlson said.

Handled solution efficiently

Eventually Forest will be reinjecting the water, but secondary recovery with water flood wasn’t scheduled to start until late 2004, Carlson said, so in the meantime, the company had to find a place to dispose of the water and, quickly.

“A state official said Forest responded quickly to the problem of excess water production. “We got a permit to dispose of the water in a wildcard we’d purposely saved, the Tom Cat,” which was drilled and plugged and abandoned several years ago. “We built our onshore processing facilities right on top of the oil drilling pad to minimize our footprint over there,” Carlson said.

Well drilling is also going more slowly than expected. It takes about three months to drill a Redoubt well, he said, which is longer than the company originally anticipated and, combined with the other challenges, puts the company behind schedule to have seven oil wells drilled by the end of the year.

A fifth oil well is expected to come online in the next month and a half, Carlson said. Currently, “we’re re-drilling No. 4, putting it in a better location.”

“It’s going slower than we wanted. … It’s been a little frustrating that we haven’t got more wells in,” he said.

May sell gas from Redoubt

In May, the company completed and put online its first gas well, Redoubt No. 3, which recently tested at 8.6 million cubic feet a day.

“We had some mechanical problems in the Hemlock with No. 3. We had a gas discovery there, so we completed it as a gas well,” Carlson said.

“No, it also tested a little bit of gas. We’re re-drilling it now to make it a more efficient producer.” Because of what Forest has found so far, Carlson said it is “highly likely (Redoubt has) … more gas potential in the shallower sand, which is where we found gas in No. 3.”

The gas, which has proven another distraction from the company’s main objective — to produce oil — will be used for fuel for the rig when the operation is shut down.

“If there’s enough gas, we’ll sell some. We’re evaluating what we’re going to do now,” he said, “but we didn’t count on any gas. … We want to drill oil wells.”

continued from page 1

INSIDER

“...”

A couple of years ago they were talking about an open season, but things have changed. Before you explore for gas, drill too much, you first want to be sure you have access to a pipeline,” he said.

The Alaska Division of Oil and Gas has approved Anadarko’s application for gas exploration operations, originally filed last July and revised late last year, for the state portion of the plan. Part of the exploration would be done on Arctic Slope Regional Corp. lands in the same area.

The Arctic Chair 1 would be drilled on state lease ADL 389763 in section 35, township 2 north, range 10 east, Umiat Meridian. The Dolly Varden 2 would be on the sale lease, in section 22, T2S-R10E, UM. Dolly Varden 4 would be on ADL 389764 in section 19-T2S-R11E; UM. Dolly Varden 7 on ARSC lands in Section 9, T2S-R12E, UM.

The drilling locations are some 60-70 miles south of Deadhorse and 10-20 miles west of the Dalton Highway. Anadarko has proposed various operations plans, including plans to stage a rig at the old Aueis airstrip and a plan to move a rig from Deadhorse each year.

Gardner sells Fairweather shares

Bob Gardner, a founder and president of Anchorage, Alaska-based Fairweather Exploration and Production, recently sold his shares in the company to co-founders Sherron Perry, Jesse Mohrbacher and two more recent partners. Gardner, determined to find more leisure time in life, serves as senior technical advisor to the company.

Jesse Mohrbacher is the new president, Parker Perry is senior vice president and heads up Lower 48 operations. Partner Bill Penrose is senior project manager and runs the company’s Alaska operations.

Fairweather E&P provides a broad range of oilfield services.

Fire destroys Umiat lodge

The Umiat Lodge and several outbuildings were destroyed by fire June 10. Umiat is a small community about 150 miles along the Canning River, which borders the Arctic National Wildlife Refuge.

The acreage includes all leases in the Kavik prospect and what used to be the Keskuk unit. Anadarko owns a two-thirds interest in the leases and Encana held a one-third interest.

Anadarko’s Alaska spokesman, Mark Hanley, told Petroleum News June 10 that Anadarko’s April acquisition of BP’s interest in 230,000 acres (76,700 acres net) of state leases in the Brooks Range Foothills, took Anadarko over the 500,000 acre state exploration lease limit.

“That deal put us over the acreage limit, so we had to go out and prioritize our leases in areas where we have the most interest. We supported the legislation that raised the 500,000 acre cap; and that bill has since gone through, but we couldn’t depend on its passing,” Hanley said.

Encana, he said, agreed to also drop its interest in the eastern North Slope leases.

Anadarko is looking for a third partner for its Brooks Range Foothills acreage. Hanley said. In addition to stake acreage in the foothills, Anadarko has a two-thirds interest in 1.2 million acres of Arctic Slope Regional Corp. land. EnCana is a one-third partner in that acreage.

Corbus tears Achilles tendon, stranded gas meeting canceled

Top level officials with Alaska Gov. Frank Murkowski’s administration were expected to meet with North Slope producers for stranded gas negotiations in the second week of June, but the meeting was postponed because Department of Revenue Commissioner Bill Corbus tore his Achilles tendon. Corbus was admitted for surgery June 11 and will lie in bed for approximately 10 days, a Revenue official told Petroleum News.

A new meeting with the producers has not been scheduled.

Oil Patch Insider is compiled by Paula Eastley and Kay Cashman. If you have a news tip or press release for Oil Patch Insider, please email publisher@PetroleumNews.com, phone (907) 522-9469, or fax (907) 522-9583.
Canada out to head off Alaska gas pipeline subsidies, meet with U.S. officials

Tax breaks to support construction of an Alaska Highway gas pipeline and energy’s critical role in U.S.-Canada trade relations are on the table in two days of high level meetings in Washington, D.C.

Leaders of the Canadian Association of Petroleum Producers are meeting with U.S. policy makers June 11 and 12 at a time when energy issues are dominating Washington’s domestic agenda and the U.S. is under special pressure to find new gas supplies.

In conveying their industry’s views of the sweeping energy bill before the U.S. Congress, the Canadian Association of Petroleum Producers delegation will again register Canada’s opposition to proposed tax credits for the $20 billion pipeline from the North Slope.

Association President Pierre Alvarez told the Financial Post that a North American gas market has evolved based on open deals, free trade and an absence of government intervention.

“We would prefer to see government not affect prices in the marketplace,” he said.

Although Canadian government leaders have indicated they will not object to loan guarantees to help finance a pipeline, they and the industry are flatly opposed to tax credits that would kick in when gas prices fell below $3.25 per thousand cubic feet, but would be paid back when prices approached $5.

The association team will also emphasize Canada’s importance as the largest supplier of crude and gas to the U.S. market, exports that topped C$38 billion in 2002.

Alvarez said that given the record of success, the association wants to ensure that “governments don’t do things that either slow down bringing new supplies (into production) or prejudice one project against another.”

—GARY PULK, Petroleum News Calgary correspondent
Unocal may further reduce gas to Agrim

Agrim said June 2 that Union Oil Company of California may further reduce its supply of natural gas to Agrim’s Kenai, Alaska, fertilizer facility. While the timing, volume and duration of these reductions is uncertain, Agrim said Unocal indicated the reductions may occur as early as the summer of 2003.

Agrim said it disputes Unocal’s attempt to unilaterally reduce its gas deliveries to the Kenai facility and continues to pursue legal remedies in regard to Unocal’s reduction in natural gas supply. In addition, Agrim said, it is continuing to have discussions with other potential natural gas producers regarding the supply of natural gas on both a short and long term basis to attempt to offset Unocal’s failure to supply sufficient gas and thereby minimize the impact to employees at Kenai.

In the event Unocal reduces natural gas supply as indicated and Agrim is unable to continue to source additional natural gas from other suppliers, Agrim may be forced to reduce production at the Kenai nitrogen facility to as low as 50 percent of capacity, the company said.

Agrim said in April that it would lay off approximately 65 employees at the Kenai plant over the next several months, as a result of an extensive analysis begun in late 2002, “to improve the facility’s efficiency and operating costs” for competitiveness worldwide, “and in light of the current gas supply issues with Union California.”

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Agrim said in April that it would lay off approximately 65 employees at the Kenai plant over the next several months, as a result of an extensive analysis begun in late 2002, “to improve the facility’s efficiency and operating costs” for competitiveness worldwide, “and in light of the current gas supply issues with Union California.”

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**CRISIS**

greeting economic recovery could be under-

He called for expansion of liquefied natu-
rmal gas imports, allowing the United States to use worldwide gas supplies as a “safety valve” should North American production become too tight.

Abraham: only limited opportunities to increase supply

Energy Secretary Spencer Abraham, in a letter to 30 senators released June 9, said that “conservation, energy efficiency and fuel switching” will be crucial to satisfy demand in the next 12 to 18 months. He said “there are only limited opportunities to increase supply.”

Abraham has called a June 26 emergency meeting of his privately funded advisory group, the National Petroleum Council, to deal with the shortage and head off dangers that gas could top last winter’s spike of $12 per million British thermal units.

“The challenge requires us to act today,” he said June 4, noting that gas in storage dropped to 623 billion cubic feet in early April, raising fears that it could enter winter at a record low of 2.6 trillion cubic feet, or the equivalent of what was burned last win-
ter.

The Energy Information Administration estimated gas in storage at 1.2 trillion cubic feet as of May 30, up 114 billion cubic feet in a week, but still 755 billion cubic feet or 39 percent below the levels of a year ago and 484 billion cubic feet or 29 percent below the five-year average.

Carl English, president of Consumers Energy, a subsidiary of CMS Energy, told the House committee June 10 that signifi-
cant actions must be taken or gas markets will “remain tumultuous and the 64 million homes and business in our country using natural gas will suffer the consequences.”

**Chronic gap between supply and demand**

Anadarko Petroleum Vice President Richard Sharples told the committee a chronic gap between gas supply and demand should be closed by lifting regulatory bar-
siers to exploration and development, espe-
cially on federal lands.

Hal Kvisle, chief executive officer of Calgary-based TransCanada, testified before the committee that his company expects North American demand to outstrip supply to gas-dependent heavy industries, such as the petrochemical sector.

Output from U.S. fields dropped by 3 percent to 5 percent last year and is not like-
ly to recover this year with conventional E&P companies keeping a tight hold on their exploration budgets.

Little hope for more Canadian gas

Although the pace of drilling has quick-
ened in Canada, there is little hope that Canadian sources can raise their share of the U.S. market above 15 percent.

The committee confirmed that settings that the aging Western Canada Sedimentary Basin, which ships 60 percent of its production to the United States, needs 11,800 wells this year — 500 more than the latest forecasts — just to hold the line on output.

The UBS report said Canada’s total pro-
duction fell 5.2 percent in May from a year earlier and has dropped by 3.5 percent this year over the same period of 2002.

FirstEnergy Capital expects Western Canada Sedimentary Basin production to decline by 5 percent to 6 percent this year or 1 billion cubic feet per day.

However, not everyone is ready to sign off on the Western Canada Sedimentary Basin. Shell Canada executive Larry Marks told a petrochemical conference June 9 the basin will remain in the forefront in Canada and “will continue for a number of years before the frontiers catch up.”

He said Shell Canada, based on the plays it is pursuing, is certain estimates of Western Canada Sedimentary Basin potential reserves are “too conservative.”

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**Explanation & Production**

**Imperial Oil tackles Nova Scotia deepwater challenge off Canada’s East Coast**

Imperial Oil is diving in where others are hesitant to tread by announcing its first deepwater drilling program off Canada’s East Coast.

It has awarded a contract for drilling services to Ocean Rig Canada to use the semi-
submersible drill vessel Eirik Raude to start drilling on the Scotian Slope as early as next month. Imperial, 69.6 percent owned by ExxonMobil, obtained 100 percent exploration rights to two parcels covering 618,000 acres in water depths ranging from 450 feet to almost 10,000 feet in return for drilling commitments of $160 million.

Three-dimensional seismic was acquired in 2000 and 2001 and last year Imperial used advanced ExxonMobil technology to evaluate the acreage.

Imperial will be the operator of the well and Talisman Energy will earn a 30 percent equity interest in two deepwater licenses by participating in the drilling of an explo-
tion well on one of the blocks.

Imperial Senior Vice President K.C. Williams said in a statement that the offshore Nova Scotia deepwater play “contains a number of large, high-potential exploration lands, but remains unproven.”

Despite the geologic risks and high drilling costs, he said it is prudent to “test this significant opportunity now.”

Imperial also has a 9 percent working interest in the producing Sable natural gas project, a 20 percent interest in six shallow-water offshore parcels near Sable and a one-

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**LNG lacks infrastructure**

Any talk of quickly stepping up the pace of LNG import is inhibited by a lack of infrastructure and stern environmental oppo-
sition to offshore facilities.

Regardless of proposals to increase U.S. import terminals to 22 from four, plus four more for Mexico’s Baja California, Lehman Brothers analyst Thomas Driscoll sees LNG making only steady gains from 1 percent of U.S. domestic supply currently to 5 percent in 2006 and 10 percent in 2010 over a peri-

d when U.S. consumption is forecast to grow from 22 trillion cubic feet a year to well over 30 trillion.

The harsher alternatives, while longer-
term answers are developed, could extend to demand destruction, or closing off deliveries to gas-dependent heavy industries, such as the petrochemical sector.

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BP opposes proposed Prudhoe Bay rules

At AOGCC hearing operator suggests alternative annular pressure rules

By KRISTEN NELSON
Petroleum News Editor-in-Chief

AR e new operating rules necessary for Prudhoe Bay wells? And if so, what kind of rules?

In the aftermath of the explosion at the A-22 well at Prudhoe Bay last August which seriously injured a BP worker, the Alaska Oil and Gas Conservation Commission has proposed new rules governing annular pressures in Prudhoe Bay development wells. Annular pressure was determined as the cause of the explosion.

Prudhoe Bay operator BP Exploration (Alaska) and the Alaska Oil and Gas Association testified at a November hearing that operating procedures and training had been revised after the explosion and told the commission that no new commission rules were necessary.

The commission disagreed. It published proposed new regulations in April and heard testimony from BP May 27 on those proposed regulations.

Steve Rossberg, BP’s Prudhoe Bay wells manager, testified for BP. He told the commission that BP and the other Prudhoe Bay working interest owners continue to believe that no new rules are necessary. “BP continues to believe,” Rossberg said, “that sustained casing pressures are appropriately addressed by its well integrity program parameters.”

If the commission does adopt new rules, he said, BP recommends changes.

BP asking for changes

First, he said, BP believes that the commission should include definitions of inner annulus, outer annulus and sustained pressure in a new rule.

Ruedrich said that in the November hearing, “BP indicated that clearly rules needed to be flexible . . . one size does not fit all.” In response to that, he said, the commission wrote a flexible rule, which BP opposes.

The commission has proposed requiring that the operator demonstrate, by mechanical integrity testing, that all wells can be safely operated. BP proposed that the rule require it to conduct and document a pressure test of tubulars and completion equipment, or installation and replacement. Once installation is done, monitoring and surveillance would ensure that integrity is maintained.

In response to a question from Commissioner Randy Ruedrich, Rossberg said that while BP does use mechanical integrity testing in its operations, it is not always the most reliable means of testing tubing once a well is online, “so what we’re asking,” he said, “is that other options be allowed other than just straight mechanical integrity testing.”

The commission’s proposed rules require that wells be monitored daily for pressure. BP recommended that the rule provide an exception for weather conditions or emergency situations. Rossberg told the commission that wells are monitored on a daily basis, but would like a rule to acknowledge “unusual circumstances when it is not safe or not feasible to monitor a well on a daily basis.”

Frequency of bleed, pressure measurement

Ruedrich asked about the technical basis for doing two bleeds a week of well pressure.

Rossberg said wells need to be bleed to start them up. In addition, for wells with outer annulus pressure the threshold is 1,000 pounds per square inch pressure. “And we ask that the operators report any wells that cannot be kept below that pressure with two or fewer bleeds per week,” he said.

The two bleeds a week standard, he said, has developed through 20 years of operating Prudhoe wells.

The commission wants to receive reports of wells with pressure problems, and has proposed a standard of “sustained inner annulus pressure or outer annulus pressure greater than 20 percent of the burst pressure rating of the annulus’s outer tubular.”

BP proposed defining the pressures as the thresholds it now uses: for the inner annulus, 2,500 psi; for wells processed through the Lisburne Production Center and 2,000 psi for other Prudhoe Bay development wells; and 1,000 psi for the outer annulus.

Ruedrich said that in the November hearing, “BP indicated that clearly rules needed to be flexible . . . one size does not fit all.” In response to that, he said, the commission wrote a flexible rule, which BP opposes.

“Why the change?” he asked.

Rossberg said the request for flexibility reflected differences in wells at Prudhoe Bay and other North Slope fields. That difference, he said, is reflected in BP’s definitions of inner annulus pressure as 2,500 psi for Lisburne wells and 2,000 psi for other Prudhoe wells.

“At Prudhoe Bay and Lisburne,” he said, “we have some of the highest gas-lift pressures in the world. Those systems run at 2,000 pounds, 2,500 pounds, respectively.”

Administrative control

Ruedrich asked why a percentage system would be more difficult than a fixed number when the operator would be doing the same thing, reading the pressure gauge, regardless of the system.

The well pressure safety system is based on administrative controls, Rossberg said.

“With administrative controls, you work, the key element is people to follow those controls. They have to understand and follow them.” A percent-

able system, he said, would result in “a different pressure limit on each well, they’d be less well understood by the operators and we think . . . result in a higher likelihood that we would miss a threshold pressure.”

Ruedrich said the operator is just col-

ECTED in the data, and is not the ultimate decision maker. The technology in a data-

base, he said, could compare an actual reading with casing specifications — the management system, he said, would iden-

tify problems, not the operator.

Rosberg said there is technical justifi-

iation for the 1,000, 2,000 and 2,500 psi numbers. “They provide an ample safety factor and are well within the range of all of our casing design on the slope,” he said.

There are some 1,500 wells to manage at Prudhoe, Rosberg said, there are “at least six generations of casing design, wellbore design” and they “do have slightly different threshold pressures and it would make it more difficult, I think, to identify a well that exceeds specific threshold versus a consistent 1,000 and 2,000.”

Rosberg said the percentage measure was a concern “because we do view the operator as the first line of defense in well integrity” and want “a very clear, understand-

able and consistent trigger pressure that that operator knows that he has to report.”

Because while operators are required to read the pressure gauge daily, he said, “that data isn’t recorded.” What’s crucial, he said, is that the operator knows what pressure reading he needs to report a well, and “we do have four, five or six differ-

tent well designs on any given pad.” The existing trigger numbers cover all of those designs, Rosberg said, but with a per cent-

rule, the trigger points for wells would vary.

The commission expects to issue a final rule within 30 days.
BP review finds world oil supply more diverse

Company’s 52nd statistical review says non-OPEC production increasing

BP review finds world oil supply more diverse

WORLDWIDE crude oil and natural gas prices up in May

The Energy Information Administration said in its short term forecast issued June 6 that average worldwide crude oil prices rose in May as continued reports of low oil inventories trumped expectations that Iraqi oil production would quickly return to pre-war levels. Those hopes faded on the news that post-war looting would postpone for some months the return of the Iraqi oil sector to normal operations, the agency said.

In addition, a terrorist attack in Saudi Arabia and estimates of lower production in Saudi Arabia by some analysts combined to push prices upward. By early June, EIA said, the Organization of Petroleum Exporting Countries basket price had risen to its highest level in two months, and is now in the upper end of OPEC’s target range of $22-$28 per barrel.

The natural gas spot price at the Henry Hub has remained well above $5 per million British thermal units on a monthly basis since the beginning of the year and is above $6 per million Btu in the first week of June. The agency said the low level of underground storage is the principal reason for these unsustainably high prices and predicted that natural gas prices will likely remain high as long as above-normal storage injection demand competes with industrial and power sector demand for natural gas.

Above average prices, strong drilling needed

Above average prices and strong gas-directed drilling efforts this year will be needed to ensure that gas in storage reaches at least minimally adequate levels by the beginning of the next heating season, the agency said. If adverse weather inter-
SUPPLY

regions, that have begun to grow rapidly.”

Non-OPEC production increases

Production from Russia, the Caspian, the deepwater Atlantic Basin and Canada is up 3.3 million barrels a day (26.5 per-
cent) in three years and has the potential to increase another 5 million barrels a day by 2007, BP said.

China accounted for 68.5 percent of the increase in global primary energy consumption in 2002 and has become a major energy consumer and importer. Consumption of coal, which accounts for 66 percent of Chinese energy use, grew a massive 27.9 percent. Oil consumption increased 5.8 percent or 332,000 barrels a day, accounting for all of the world’s oil consumption growth in 2002, China replaced Japan as the world’s second largest oil consumer.

Natural gas consumption growing

Natural gas is the world’s preferred non-transport fuel, BP said. Outside the Former Soviet Union gas consumption has grown 3.4 percent a year over the past decade and its share of total energy con-
sumption is now roughly equal to coal at 24 percent.

U.S. gas consumption grew 3.9 per-
cent in 2002 as North American gas pro-
duction fell 1.8 percent. Imported lique-
ified natural gas is filling part of the gap. Producers are now considering options for delivering new sources of pipeline gas and LNG to this growing gas market.

Commercial (non-hydro) renewable energies are growing rapidly, but their contribution to total world electricity gen-
eration remains small (1.7 percent in 2000 versus 1 percent in 1990), BP said.

Oil prices up slightly, consumption flat

Brent oil prices averaged $25.19 a bar-
rel in 2002, up slightly on the 2001 aver-
age price of $24.77 and well above the post-1986 annual average of $19.40. Prices during 2002 ranged from a low of around $18 per barrel in mid-January to peak just before the end of the year at $32.

Global oil consumption was broadly flat, increasing 290,000 barrels a day from 75.5 to 75.7 million barrels a day. All of the increase is attributable to China where oil consumption increased 5.8 per-
cent or 332,000 barrels a day.

Global oil production declined 415,000 barrels a day, or 0.7 percent, from 74.4 million to 73.9 million barrels a day. OPEC daily oil production fell to 28.2 million barrels a day, a drop of 1.87 million barrels a day (6.4 percent). The steep fall resulted from a number of unplanned disruptions and because some OPEC producers, primarily Saudi Arabia, curtailed production in response to weak demand and to a significant 1.45 million barrel per day increase in non-OPEC oil output. Large daily production increases occurred in Russia (640,000 barrels), Kazakhstan (150,000 barrels), Canada (170,000 barrels), Angola (160,000 bar-
rels) and Brazil (160,000 barrels).

Natural gas consumption up

World consumption of natural gas increased in 2002 by a relatively strong 2.8 percent on the strength of a 3.9 per-
cent increase in U.S. consumption and a 7 percent increase in non-OECD Asia Pacific consumption. Growth in natural gas consumption outpaced growth in world primary energy and its share of total energy consumption is now roughly equal to coal at 24 percent.

Global natural gas production increased 1.4 percent, from 2,495 billion cubic meters to 2,527 billion cubic meters. North America was the only region to experience a production decline, falling 1.8 percent from 779 to 766 billion cubic meters. A price-driven drop in drilling activity explains some of the pro-
duction decrease, but the maturity of U.S. and Canadian gas producing basins was also a factor.

Coal fastest growing fuel

Coal was the fastest growing fuel in 2002 with coal consumption increasing 6.9 percent in 2002 on the strength of an extraordinary reported increase in China of 27.9 percent. Excluding China, world consumption increased just 0.6 percent.

Consumption of nuclear power increased 1.5 percent, with most of the increase coming in Asia. World consump-
tion of hydroelectric power increased 1.3 percent in 2002, but was still less than in 2000. Nuclear and hydroelectric power each account for about 6 percent of total world energy consumption.

Review available on net

This is the 52nd edition of the BP Statistical Review of World Energy. The BP Statistical Review of World Energy 2003 is published on the internet at www.bp.com/centres/energy where data can be viewed and downloaded.

PRICES

venes, the task could be made more difficult and even place additional upward pressure on prices.

Assuming normal weather, spot prices in the $5.50-$5.67 per million Btu range are expected for the rest of 2003.

Commenting on the forecast, Energy Secretary Spencer Abraham said June 6 that the agency “has again noted that the nation’s stocks of natu-nal gas in underground storage are unusually low due to weather factors and declines in both domestic produc-
tion and net imports.” He said indus-
try is increasing storage rates, “marked this week by a record stor-
age injection,” but he noted that hot summer weather could “exacerbate the problem.”

Abraham said he asked the National Petroleum Council to study U.S. natural gas, and has now called for a special meeting of the council June 26 because, “in my view, we cannot want to take action on the problem.”
**NEW MEXICO-COLORADO**

**XTO acquires San Juan basin gas producing properties**

Fort Worth, Texas-based XTO Energy said June 5 that it has an agreement with MarkWest Hydrocarbons of Denver, Colo., to acquire coalbed methane and natural gas producing properties in the San Juan basin of New Mexico and Colorado for $60.5 million.

XTO said its internal engineers estimate proved reserves to be 50 billion cubic feet of gas equivalent of which 78 percent are proved developed. The company said the acquisition adds some 9.5 million cubic feet per day to its existing gas production.

“Over the past six months, XTO has been very effective in acquiring choice gas properties to supplement our strong internal growth,” said Bob Simpson, XTO chairman and CEO. “This deal highlights our continuing success in expanding XTO’s core areas with the right opportunities.”

“Long-lived gas production with solid, low-risk upsides have built our company,” said Steffen Palko, vice chairman and president. “These assets fit perfectly into our operational expertise.”

The properties to be acquired are in La Plata County of southwestern Colorado and San Juan County of northwest New Mexico and will increase XTO holdings in the San Juan basin by 15,300 gross (7,663 net) acres and add another 115 operated wells. XTO said more than 70 percent of its current gas production is attributable to the high-producive Fruitland Coal formation. This transaction is scheduled to close on June 30 with an effective date of June 1.

**ATLANTA, GEORGIA**

**Mirant edges closer to bankruptcy**

GIant energy trader Mirant says it will seek bankruptcy protection — a move that would further rattle a nervous market — if creditors reject a plan to restructure $1.45 billion of debt. The Atlanta-based company, one of the leading U.S. merchant traders, offered the plan June 2 as part of a more comprehensive refinancing effort designed to avert bankruptcy.

Mirant President and CEO Marc Fuller told analysts during a May 7 conference call that the company has made solid progress toward a plan to restructure $1.45 billion of debt. The sales included the bulk of Mirant’s Canadian assets, which are valued at $0.3 billion, and $0.3 billion in other assets. They included purchasing contracts for 380 million cubic feet of natural gas, adding about 2.5 billion cubic feet to the company’s production.

However, Executive Vice President Rick Pershing said the company would retain a presence in the Canadian gas sector “because we believe Canadian natural gas is important to our U.S. operations.”

—GARY PARK, Petroleum News Calgary correspondent

**Mc Covey unit set to expire**

**By RAY CASHMAN**

Petroleum News Publisher & Managing Editor

Operator EnCana Oil & Gas has no plans to ask for an extension of the life of the McCovey Sea McCovey unit where it drilled an exploratory well this past winter. The federal unit, which includes three federal and four state of Alaska leases about 12.5 miles northeast of West Dock at Prudhoe Bay, expires June 30.

The Calgary-based independent said the McCovey No. 1 exploration well on Dec. 6 and permanently plugged it Feb. 9. A month later ConocoPhillips, a partner with EnCana and ChevronTexaco in the offshore North Slope prospect, added dry hole costs for McCovey to its preliminary 2002 financial results.

**Harding says no plans**

Pre-application permitting meetings for a second well at McCovey for the 2003-04 drilling season began last fall but ground to a halt in late January. State records show that a second plan of exploration is due by June 30 in order to hold the McCovey lease.

— RAY CASHMAN

**Anadarko buys $225 million in GOM assets from Hess**

**By ROBERT ALLISON**

Petroleum News Houston Staff

Anadarko Petroleum, just days after its stock price was hammered on disclosure of missed production targets, said June 9 it had acquired $225 million worth of Amerada Hess properties on the Gulf of Mexico’s aging continental shelf. The acquisition gives the big Houston independent an additional 4,000 barrels of oil and 57,000 million cubic feet of natural gas, adding about 2.5 million barrels of oil equivalent to the company’s 2003 volumes.

Anadarko paid $9 per barrel of oil equivalent for the 26 fields it got from Hess. They have estimated proved reserves of nearly 23 million barrels of oil equivalent, 60 percent of which is natural gas. About $190 million of the purchase price was allocated to proved reserves, with the remaining $35 million going to unproved potential that will be evaluated over the next several years, Anadarko said.

“These are high quality assets with excellent profit margins and a lot of upside,” said Robert Allison, Anadarko’s chief executive officer. “There’s considerable opportunity for reserve additions and production growth on these properties.”

**SDC headed for Canadian Beaufort**

If EnCana Oil & Gas gets the go-ahead from government agencies, the SDC — short for steel drilling caisson — will be towed later this summer from the McCovey exploration unit north of Prudhoe Bay to Herschel Island in the Canadian Beaufort where it will be stacked, a federal official told Petroleum News June 10.

“Applications to move the SDC to Herschel Island have been submitted. Approval has not been granted at this point,” Steve Harding, EnCana’s vice president of Alaska-Mackenzie Delta, said June 11.

The bottom-founded Arctic drilling platform was used this past winter to drill the McCovey No. 1 exploration well in federal waters in the Beaufort Sea off Alaska’s North Slope. The SDC can drill in 24 to 80 feet of water and can store everything needed to drill.

— ROBERT ALLISON

**New exploration is due by June 30 in order to hold the McCovey lease.**
Directional drills for crossings and right-of-way cleanup are under way for the Kenai Kachemak Pipeline. "The project is 99.9 percent complete. We’re doing directional drills right now," John Lau told Petroleum News June 10. Lau is project manager for Norstar Pipeline, the Enstar Natural Gas subsidiary formed to build and operate Kenai Kachemak, which is owned 60 percent by Marathon Oil and 40 percent by GUT LLC, a subsidiary of Unocal. The pipeline will carry natural gas from Ninilchik to Kenai.

Norstar managed the permitting, engineering and construction of Kenai Kachemak, Lau said.

He said installation of the 33-mile 12-inch pipeline is about 98 percent complete as are two of the nine directionally drilled crossings. "The nine directional drills will range in length from 700 feet to 2,000 feet," Lau said. First a pilot hole is drilled under the streambed and the hole is reamed out to a diameter sufficient to easily pass the pipeline. Then the pipe is pulled through the reamed hole, he said.

Michael Baker did engineering for the pipeline, Houston Construction was the general contractor for pipeline installation and directional drilling was subcontracted to ARB, Lau said. Construction of the terminus management station is under way with Alaska Anvil providing engineering support and general construction by VECO.

Pipeline construction began in January and construction of the terminus building began in May and both are expected to be completed in August, Lau said.

The most significant challenges came during the permitting stage, with numerous state, federal and local agencies involved each with "a number of issues that had to be addressed." Construction challenges "were attributable to above normal temperatures this past winter, causing additional complications when crossing the wetlands," Lau said.

The Kenai Kachemak Pipeline is the longest section of gas pipeline to be installed in the Cook Inlet area since Enstar’s Beluga line in 1985, he said. "Pipeline technology improvements since that period in the way of steel fabrication, pipeline coatings and construction methods such as horizontal directional drilling have improved the quality of the end product at comparably less cost," Lau said.

—PETROLEUM NEWS ANCHORAGE STAFF
Girthweld coating on KKPL. Norstar Pipeline is doing the directional drills now.

Above, ditching on KKPL. At right, lowering in the 12-inch pipe. The pipeline is 33 miles long and will carry gas from Ninilchik to Kenai.

**The Alliance**
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Many thanks to the volunteers who made today’s event a success!
Anadarko, on sagging production in Algeria, Qatar and in particular the Gulf of Mexico, announced June 5 that oil and gas volumes were down from 2003 levels of 190 million barrels of oil equivalent, including 46 million barrels of equivalent for the second quarter, down 5 percent from the company’s previous forecast of 200 million barrels of equivalent for the year and 48 million barrels of equivalent for the quarter.

“While we believe the shortfalls in Algeria and Qatar are temporary, the production issues in the Gulf of Mexico will affect us next year as well,” Allison said.

“We are still targeting strong production growth in 2004.”

In the gulf, the company said it experienced lower-than-expected production, primarily due to performance from three fields—Hickory, Tanzanite and Parther.

In the Hickory and Tanzanite fields, the company added, natural gas production dropped unexpectedly from two high-volume wells due to downhole mechanical failures. Following recompletion of the Hickory well to a higher zone, production was restored at lower rates.

Meanwhile, Anadarko opted to produce two new wells in the Hickory and Tanzanite fields from zones that are deeper than the initial targets in order to maximize recoveries, delaying production from the original target zones. However, reserve estimates for the fields will not be significantly affected, the company added.

Also, the company’s Parther field recently came on production at rates much lower than anticipated. Technical studies are under way to understand why the well is not producing as expected and to determine if a repair can be made to increase the volumes, Anadarko said.

Delays in pipeline projects

Despite early production from the Outehd field in Algeria, Anadarko said net volumes for the year were expected to be below the company’s previous forecast because of delays in several pipeline projects that are currently under construction.

The projects are expected to be completed later this year, the company said.

In Qatar, start-up delays at the Al Rayyan field, mainly due to weather, will reduce expected volumes for the second quarter of 2003 and the full year, Anadarko said. The field is currently producing more than 20,000 barrels of oil per day gross. However, production is expected to end the year at 25,000 barrels a day, rather than 35,000 barrels a day as previously forecast, the company said.

“Lately, we’ve seen some property acquisitions that offer better returns for our shareholders, so we may choose to add projects to our portfolio that would let us achieve our target,” Allison said prior to announcing the Hess property acquisition.

The company said it had identified more than 50 development opportunities in the Hess properties, including production enhancements, recompletions and low risk development wells, and as many as 10 exploration prospects that could be drilled over the next few years. The exploration prospects are located in high potential deep shelf gas plays, Anadarko said.

“More than 60 percent of the Hess reserves are concentrated within three fields: South Timbalier blocks 172 and 190, 205 and 206 and South Pass 89. The key producing fields lie within our active fairway, which means we expect to benefit from operational efficiencies,” Allison said.

Cash flow from the properties for the remainder of 2003 is projected to be $75 million, generating a cash margin of more than $29 per million barrels of oil equivalent based on the current Nyxex forward curve for oil and gas prices, the company said, adding that it financed the acquisition with available cash and credit facilities.

Some properties to be sold

Anadarko also said it intends to sell about $100 million in properties this year, excluding $40 million of assets in New Mexico that the company sold in the first quarter. Additional asset sales intended for closing prior to year end include about 20 properties in West Texas and 40 to 50 properties in the Gulf of Mexico, amounting to up to 400 barrels of oil equivalent in 2003.

“Our aim is to focus on our key assets and reduce costs,” Allison said. “At the end of the year, we expect to have fewer Gulf of Mexico fields but higher margins. This is an ongoing strategy that has allowed us to high-grade our portfolio, increase cash margin per barrel and add growth potential.”

Hess, which has been high-grading its portfolio and attempting to reduce debt, announced several property sales June 9 that included the sale of gulf properties to Anadarko. Hess also said it would swap part of its holdings in the UK North Sea Scott and Telford fields to Encana for $17 million and Encana’s 22.5 percent share in the Shell-operated deepwater Llano project in the gulf. Hess has sold about $500 million in assets during the second quarter.

Despite coming up short on production, Anadarko said it expects current commodity prices for oil and gas to more than offset the effect of the reduced sales volumes. Anadarko said it expects to earn $311 million, or $1.24 per share for the second quarter of 2003, with expected cash flow from operating activities of $740 million. That compares with the previous estimates of $1.15 per share of earnings and cash flow from operating activities of $710 million.

For the full year, the company said it expects earnings of about $1.46 billion, or $5.77 per share, and cash flow from operating activities of about $3.24 billion. That compares with the previous estimates of $1.39 billion, or $5.51 per share of earnings and cash flow from operating activities of $3.16 billion.

Natural gas discovery at Atlas

Anadarko Petroleum said June 9 it had discovered natural gas at its Atlas prospect in the remote Eastern Gulf of Mexico. The discovery well is located on Lloyd Ridge Block 50, about 175 miles southeast of New Orleans.

The well was spud in May in nearly 9,000 feet of water using Transocean’s Deepwater Millennium drillship. It was drilled to the target depth of 19,800 feet and encountered 180 feet of gross pay, portions of which are thin-bedded reservoirs, the company said.

However, operations at Atlas were suspended because of strong seasonal water currents, but the company said it intends to resume drilling this fall with a sidetrack well to obtain conventional core samples, which will help determine reservoir quality.

The company provided no reserves estimates for Atlas.

To date, Anadarko has made two discoveries — Atlas and Jubilee — out of three wildcard wells drilled in its Eastern Gulf of Mexico program; Hawkeye was a dry hole.

The company said both discoveries would need to be part of a larger hub development in order to be commercially developed.

The Atlas well reached total depth in 21 days and is expected to $13 to $14 million, “well under budget,” Allison said. The company holds a 100 percent interest in the Atlas discovery. Within the overall eastern gulf, Anadarko holds a 100 percent interest in 36 blocks.

Anadarko said it plans to drill two more exploration prospects in the eastern gulf before the end of the year, adding a dozen exploration and development prospects to its portfolio that would let us achieve our target,” Allison said prior to announcing the Hess property acquisition.

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**B.C. park that borders Montana might contain an oil and gas bonanza**

By DON WHITELEY

Petroleum News Contributing Writer

A conflict that will resonate with Alaskans, a small piece of British Columbia’s southeast corner, just north of the Montana border, is caught in a park vs. development fight.

Perhaps not quite as high profile as the push to drill on the coastal plain of Alaska’s Arctic National Wildlife Refuge, this one has all the elements for a similar battle, including issues that cross the U.S.-Canada boundary.

The federal and provincial governments are jockeying over an appropriate role for national parks development in the province; the local member of the British Columbia Legislature believes his constituents want no part of a national park. Added to the mix are First Nations claims in the entire region.

And hanging over the whole debate is the province’s new-found love for the oil and gas sector, coupled with some geologists reports that suggest there might be an oil and gas bonanza deep in the geological formations below the contested landscape.

**Flathead Valley donnybrook**

Welcome to the Flathead Valley, and a looming donnybrook over what happens to it. Satisfying the various special interests, each of which has its own dream about how best to use the area, will likely be impossible.

It could well end up as another clash of land-use philosophies for which British Columbia is becoming world-renowned. The provincial government’s hopes for a managed biodiversity expansion in the oil and gas sector might founder on the rocks of land use issues like this one.

Bringing this to a head now is the fact that Ottawa and Victoria are indeed actively negotiating the fate of this land, and a new national park is on the table for discussion. The two governments are said to be very close to hitting a memorandum of understanding that could see the area set in motion a lengthy, and detailed, Parks Canada feasibility process aimed at creating the new park.

Joyce Murray, British Columbia’s Minister of Water, Land and Air Protection, confirmed that negotiations with the federal government over a national parks strategy are under way, and she expects a resolution soon.

“This is a very hot issue in the region,” he said. “It’s my impression as the MLA that there is a large majority of the people to whom I’m accountable who think the provincial land use planning process is giving us all the management we need; and that a federal park is unnecessary, and also the wrong kind of management for that pied territory.”

Issues in this battle are concentrated more on hunting, trapping and guiding activities (the area has very rich, diverse and healthy wildlife populations) and the potential for energy, specifically oil and gas. The southeast part of the province is already home to several coal mines, and EnCana Energy’s pilot project for coal bed methane in the Elk Valley further north.

Peats says the proposed boundaries for the park have been carefully drawn to make sure they don’t embrace any coal potential (Fording is the main operator in the area).

**Kishenhn basin could have significant potential**

But oil and gas is a different question entirely – and the Flathead Valley is already on one unidentified U.S. company’s radar screen because of a geological formation called the Kishenhn basin. The area was identified in a geological study done for the energy ministry two years ago on oil and gas potential, and it said this:

“The Flathead area has significant hydrocarbon potential in varied play types.” The study goes on to single out the Kishenhn basin as just like similar basins in China which have been prolific oil producers. The as-yet unnamed U.S. oil company has apparently identified a play that stretches from Montana north to the Elk Valley — and right through the Flathead.

“The Geological Survey of Canada has estimated a mean gas resource potential of 635 billion cubic feet and an oil potential of 382 million barrels,” says an Energy Ministry report on the area, adding that 17 percent of the oil lies in British Columbia.

Will that get in the way of a new national park? Last month’s announcement by the British Columbia Energy Ministry of a new set of royalty incentives designed to speed up oil and gas drilling activity (in part, by encouraging exploration in new areas) is a clear indication that Victoria wants much more out of the sector.

On the other hand, a park in the Flathead Valley has been a dream of environmentalists for decades, and that includes activists in the United States who see it as a natural extension of the already much larger Glacier National Park in Montana.

“I am aware that there’s controversy over this,” says British Columbia Parks Minister Murray. “I would expect the feds to address that. They have to work with people.”

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**McCovey unit.** (The first plan was filed Jan. 25, 2002.)

But according to federal regulations, EnCana has 180 days from Feb. 9 — i.e. until Aug. 8 — in which to commence a new drilling program or file for an extension of the suspension of operation that the U.S. Minerals Management Service granted them in April 2002, MMS spokeswoman Robin Cayd told Petroleum News in February. The MMS employees in charge of the McCovey unit was not in the office as this issue of Petroleum News went to press, so it was not clear whether or not the unit would automatically expire on June 30 or remain intact until August 8, but Steve Harding, EnCana’s vice president for Alaska and the Mackenzie Delta, told Petroleum News June 9 that his company does not plan to take any action that would extend the life of the unit past its expiration date.

**State to re-offer leases**

The state Division of Oil and Gas said the state leases within the McCovey unit would be offered for lease in the next Beaufort Sea sale, which will be held Sept. 24.

In the Oct. 24, 2002, Beaufort Sea state area wide oil and gas lease sale the three exploration partners formed a bidding group that took five leases adjacent to the McCovey unit on the south, 12,160 acres, at prices ranging from $1.29 to $28.75 an acre. An EnCana and ChevronTexaco bidding group also took three tracts (7,690 acres) to the southwest of McCovey, paying $42.69 an acre for one tract and $11.29 an acre for the other two.

None of those leases were included in the McCovey unit.

**Alaska still priority for EnCana**

On Feb. 5, two days after EnCana filed an application to permanently plug the McCovey No. 1, the company’s CEO Gwyn Morgan listed Alaska, along with the Gulf of Mexico, Mexico, Australia and North Africa, among EnCana’s “high-impact opportunities to be drilled” in a presentation to a Credit Suisse First Boston energy summit.

Although there was no mention of upcoming Alaska drilling in the company’s Feb. 20 news release containing highlights of its first year in existence and its plans for 2003, EnCana is now being rated among the likely bidders for leases in the June 17, 2004, National Petroleum Reserve-Alaska lease sale.

Along with ConocoPhillips, Anadarko Petroleum and Total, the company has expressed optimism that NPR-A has untapped potential, despite the shrinking interest in the region by North Slope producer BP. EnCana picked up its first leases in the NPR-A in June 2002.

In a conference call with analysts on Feb. 20, Morgan pledged to continue exploration in the state.

He said he had “nothing new to report” on McCovey, noting it was not ready for a well but that the company was plugged and abandoned without any comment being made until after the mandatory period for disclosure.

The well, drilled from a surface location in federal OCS lease block Y-1577 to a bottom hole location to the northwest in OCS lease block Y-1578, was drilled in 2001. EnCana earned EnCana a 30 percent interest in the unit leases held by a 50-50 partnership of ConocoPhillips and ChevronTexaco.

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Drilling operations at McCovey were overseen by Fairweather E&P Service’s Anchorage office. If commercial quantities of oil were found at McCovey, EnCana had said the SDC could, with modification, have been used for a development platform.
Unocal plans Gulf of Mexico asset sales

Company’s goal to lower costs, fund international growth

Unocal said June 5 that that it will sell assets—primarily oil and gas fields in the Gulf of Mexico region—to reduce the company’s operating and depreciation, depletion and amortization unit costs and to lower corporate and business unit administrative and general costs. Cash flow from operating activities and proceeds from sales would be used to reduce debt and other financing, the company said.

Charles Williamson, Unocal’s chairman and CEO, also said the company’s focus on large development projects is beginning to pay off, with production from the West Seno deepwater project in Indonesia expected within 30 days. The company expects a reduction of 20 percent in deepwater Gulf of Mexico cash expenses which will “allow us to continue to explore our attractive international growth program,” Williamson said.

What the company is selling is its working interest in some 75 other fields in the Gulf of Mexico area, properties which, Williamson said, “only represent a net average daily production of approximately 25,000 to 30,000 barrels of oil equivalent per day and proved reserves of 40 to 50 million BOE.” Unocal said that with asset sales and cost reductions in the Gulf of Mexico, it expects to reduce Lower 48 finding and development costs to below $8 per BOE.

Deepwater Gulf of Mexico

Unocal said it will continue to explore for and develop major oil and gas accumulations in the deepwater Gulf of Mexico. It expects to drill between three and five wildcat exploration wells per year in the deepwater GOM over the next few years, but will relinquish a number of primary-term outer continental shelf blocks not considered prospective enough to warrant additional rents.

Williamson said the company expects a reduction of 20 percent in deepwater Gulf of Mexico cash expenses which will “allow us to continue to explore our inventory of high-potential drill sites.” The company will record a pre-tax $25 million charge associated with the early relinquishment of these blocks in its second quarter 2003 results.

Unocal said it is near completion on an appraisal well on the Champlin discovery in Atwater Valley block 63 and will then drill its St. Malo prospect in Walker Ridge and the Myrtle Beach prospect in Green Canyon.

“Improving the sustainability and profitability of our domestic E&P businesses and reducing across-the-board costs will help to highlight our attractive international growth program.” —Charles Williamson, Unocal

The level of debt reduction could be substantially higher, the company said, depending on the amount and timing of the proceeds from the sale of the Gulf of Mexico assets, the Matador Petroleum investment and various non-core assets (real estate holdings and certain non-E&P business interests).
ONTARIO, CANADA
Inco strike carries multi-million dollar cost
Inco has slashed in half output at the world’s largest nickel mine and estimates the after-tax cost of a drawn out strike at its Ontario operations will run to US$20 million a month.
Since 3,200 members of the United Steelworkers of America walked off the job June 1, affecting 9 percent of the world’s nick- el production, benchmark prices on the London Metal Exchange have climbed 4 percent.
But Inco has warned its regional sales offices, which have con- tinued selling nickel from Manitoba, European and Indonesian mines, will soon declare force majeure on sales contracts with nickel, cobalt and copper customers.
Standard and Poor’s Rating Services has warned that a lengthy strike could impact Inco’s BBB- credit rating.
In its scramble to plug the gap, Inco said it plans to develop a new nickel deposit in Indonesia.
Canada’s other leading nickel producers, Falconbridge and Sherritt International, said the world market for nickel was already tight, especially with China leading rapid expansion of the stainless steel industry.
—GARY PARK, Petroleum News Calgary correspondent

FAIRBANKS, ALASKA
Movement on Healy plant
Talks have resumed over the fate of the shuttered experimental coal-fired power plant built in the Interior Alaska community of Healy with nearly $300 million in state and federal funds.
Board members from Golden Valley Electric Association and the Alaska Industrial Development and Export Authority met May 29 at the Healy Clean Coal Project, the second gathering since early April of the two groups locked odds over the shuttered facility.
“It was very good for the AIDEA board to see reality … to talk to the plant operators,” said Kate Lamal, vice president of power sales at Golden Valley. “After the meeting last week, there will be some movement.”
The two boards agreed to set up a joint task force to come up with a plan for restarting the plant, which has sat idle since completion of a 90-day test period in December 1999.
“We’re working with them to see if there’s some way to get the plant operating,” said Steve Haageson, Golden Valley president. “I think we’ve started down that path.”
The U.S. Department of Energy provided the largest share of funds for the Healy project in a $177.3 million grant awarded in the early 1990s. State funds, including $85 million in AIDEA bonds, pro- vided most of the remainder.
Shortly after construction was complete in November 1997, Golden Valley and AIDEA began debating the reliability and eco- nomics of the experimental plant. Golden Valley also contends that other issues that must be addressed are safety and long-term viabili-

 Gil’s golden future
Advanced exploration project east of Fort Knox gold mine shows high-grade veins in spring drilling program, work will continue through summer
By PATRICIA JONES
Petroleum News Contributing Writer
A ssaay results from exploration drilling conduct- ed this spring on the Gil gold project, located about six miles east of the Fort Knox gold mine in Interior Alaska, surprised operators with some high-grade intercepts.
Kinross Gold Corp., operator of Fort Knox, and its partner on the Gil project, Vancouver, B.C.-based Teryl Resources, released assay results May 28 from nine exploration holes drilled about a month ago.
It’s the first part of an $830,000 exploration pro- gram planned at Gil for 2003. A total of 60 holes will be completed, consisting of approximately 17,000 feet of drilling.
Should that first phase produce favorable results, a second phase of exploration — involving an addi- tional 74 holes totaling 22,000 feet, budgeted for $590,000 — is planned for the later part of the year.
Notable about initial results from the first phase of exploration is a 35-foot interval, taken from the North Gil zone, which assayed 0.36 ounces of gold per ton of rock. By comparison, average grade of ore mined and milled at Fort Knox is a little less than 0.03 ounces per ton of rock.
“This is one of the richest intercepts found over this length … it’s exciting to find new zones of high grade (mineralization),” said John Robertson, presi- dent of Teryl, which holds a 20 percent share of the Gil property. “The drilling is very positive — com- ing up with this high grade is better than we antici- pated and it was a nice, pleasant surprise.”
Kinross, which holds an 80 percent share of Gil, operates the exploration program. Ted Wilton, the company’s chief geologist at Fort Knox, said at press time that he had not yet obtained permission to comment on the drilling results.
Two new targets identified
Another high-grade intercept hit by drillers this spring was a 15-foot section averaging nearly a half- ounce of gold per ton of rock, taken from the Sourdough Ridge Zone, a relatively new prospecting target at Gil, Robertson told Petroleum News on June 4.
“We had drilling all over the property and encountered some mineralization there about three years ago, but the target was located just last year,” Robertson said. “Rocks on the surface were similar to the Main Gil, but it’s got high grade zones in
with some high-grade intercepts.
Another new exploration target, dubbed the Skam Grid, also produced a small, high-grade inter- val, Robertson said.
“Drilling these holes is based on geophysical tar- gets — they’re looking for the source of the gold,” he said.
Focus on known resource
Robertson said future drilling will focus on the North Gil and the Main Gil zones. “They will go where they know they have a substantial strike length,” Robertson said.
Current reports show the Main Gil zone is believed to be 3,000 feet in strike length and 70 feet thick, Robertson said. Mineralization at North Gil covers a zone 1,000 feet long and 500 feet wide, and it appears to be open in all directions except to the north, Robertson said.
“Kinross wants to establish the presence of addi- tional mineralization and to also take the drill-indi- cated resources to the proven category,” he said.
“We’re hoping this mine will be the next to go into production.”
In addition to the drilling, a 375-foot trench was excavated, and a bulk sample of mineralized materi- al was shipped to Fort Knox for testing.
“It’s compatible, so there’s no contamination problems,” Robertson said. “They would not be drilling on the property if they were not able to mine it.”
Mineralization at Gil has been located close to the surface, he said. Most drill holes are 300 feet or less in depth, he said, and some mineralization has been encountered “right up to the surface,” he said. “The less waste rock you have, the cheaper it is to mine.”
More gold needed
Earlier this year, Fort Knox general manager Rick Dye said 2003 exploration work at Gil was designed to advance the property to a feasibility and permit- ting stage in 2004.
The company announced plans to spend $3.2 mil- lion on exploration this year, which includes in-pit work, as well as prospecting at the nearby True

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OFFSHORE ANGOLA
Block 32 discovery offshore Angola
Exxon Mobil Corp. said June 3 that its subsidiary, Esso Exploration Angola (Block 32) Ltd., has participated in a deepwater oil discovery on Block 32 offshore Angola.

The discovery well, named Gindungo-1, was drilled in 4,700 feet of water, ExxonMobil said. The well flowed at 7,400 and 5,700 barrels per day from two separate zones. It is the first exploration well on Block 32, which is located approximately 102 miles offshore Angola.

Sonangol, the Angolan national oil company, is the concessionaire of the block and Esso has a 15 percent interest. The other Block 32 interest owners are Total (operator 30 percent), Marathon Oil (30 percent), Sonangol (20 percent) and Petrolag (5 percent).

Esso holds interests in six offshore deepwater blocks in Angola covering an excess of 7 million gross acres.

SYRIA
Devon signs agreement for work in Syria
Oklahoma City-based Devon Energy said May 31 that it and partner Gulfsands Petroleum have entered into an agreement with the Syrian government and the Syrian Petroleum Co. to explore for oil and natural gas in Block 26 in northeastern Syria.

The terms of the exploration, development and production sharing contract require the companies to pay a signature bonus of $1 million and, during the initial four-year term of the contract, to conduct geologic and geophysical studies, acquire seismic data and drill four exploration wells. Devon said the companies’ total obligation under the contract is some $17 million.

Block 26 covers an area of more than 11,000 square kilometers and the agreement excludes the Syrian Petroleum Co.’s existing fields located within the outer perimeter of the block. Devon said the existing fields are producing more than 120,000 barrels of oil per day and will continue to be owned and operated by the Syrian Petroleum Co.

“The Syrian partnership focuses on exploration around areas with proven reserves. It could, over time, expand to include cooperation between Syrian Petroleum Co. and Devon on additional development and production enhancement projects in the area,” James Hackett, president and chief operating officer of Devon, said in a statement.

SAUDI ARABIA
Saudi Arabia withdraws from $15 billion deal with Exxon Mobil
Saudi Arabia called off a proposed $15 billion deal with a group of oil companies led by Exxon Mobil Corp. to develop its massive eastern gas fields, a Saudi oil official said June 6.

The official, speaking to The Associated Press on condition of anonymity, said Saudi Oil Minister Ali Naimi notified the companies June 4 that the country has revoked a memorandum of understanding signed three years ago regarding the development of the South Ghawar gas field, 149 miles southeast of the capital, Riyadh.

The Saudis and the companies apparently disagreed on the terms of the agreement, including the amount of gas reserves the companies will handle and revenues, see DAILY page 17.

B R I T I S H C O L U M B I A , C A N A D A
A lady gone
Ladyfern production dropping steeply after only a few years
By DON WHITELEY
Petroleum News Contributing Writer

picture four-10-year-old boys — each with a straw, but only one milkshake. It’s simple, and calculating how long it will take for the milkshake to disappear.

About four seconds?

“Doig has a point. At Ladyfern’s production peak more than a year ago, gas prices were about $3 per thousand cubic feet. A year later, with Ladyfern production down by 70 percent, those prices had more than doubled. At today’s gas prices, gross revenues from Ladyfern at peak production rates would be $4 million per day, as opposed to $1.2 million per day at current production levels.

Analyst Molyneaux isn’t so sure: “It is a big reservoir, but it doesn’t cover a large area extent,” he said. You’ve got four companies that put straws into this thing and pulled on them hard. We’ve modeled this out and we can’t make the case that it was done too hard, not with what was known at the time. In hindsight, maybe you could have been a little more gentle.”

Molyneaux also points out that Ladyfern’s production was a North American “first” — providing a huge incremental volume of gas at a time when demand was extremely high and other supplies were in decline, or at best staying flat.

“I don’t know where we would have been without it,” he said.

EnCana took it to a capitol
Michael Graham, EnCana’s senior vice president, Foothills region, says the rapid rate of production was definitely a result of competition among the four big players.

“Oil companies would normally develop it on quite a bit longer,” he said. “I don’t think we’ve lost anything; we’ll ultimately get our share. But we’ve done it quite a bit quicker spending quite a bit more capital than maybe we would have liked.”

But Doig suggests that the agreement was too late, and that such a rapid depletion is costly to the owner of the resource.

“So who is the loser? In this case, it’s the citizens of B.C.,” he said. “A lot of money flowed in, but if you work it out, a lot more money could have flowed in if they had something called good conservation methods attached. Each company says they made money, but when you ask them ‘could you have not made more money,’ they don’t deny that.”

Was agreement too late?

All the players went to ridiculous, and costly, lengths trying to get an upper hand on what looked like a spectacular find. Some of the first wells flowed at unheard-of rates of 100 million cubic feet of gas per day Analyst Molyneaux described the rush as “hand to hand combat.”

Not the first evaporating gas discovery
This isn’t the first time British Columbia has seen a spectacular natural gas discovery evaporate. In the 1970s, the Athabasca Petroleum made two huge natural gas discoveries called Beaver River and Pointed Mountain — a region range to the west of the rest of the Ladyfern discovery. But before any gas started flowing, the gas reservoir became flooded with water, making it impossible to produce the gas. Westcoast Transmission...
Gas authority members named, to meet June 16

By KRISTEN NELSON

A laska Gov. Frank Murkowski has appointed seven members to the Alaska Natural Gas Authority, created by an initiative in last November’s general election to develop, construct, manage and operate a gas pipeline from the North Slope of Alaska and a spur line to Southcentral Alaska.

The authority’s goal is to have the Alaska gas line in full production by 2007.

“The members of the Alaska Natural Gas Authority represent the important commitment by the state to bring Alaska’s natural gas to market,” Murkowski said June 9.

The first meeting is set for Monday, June 16 at the Department of Revenue’s conference room in Anchorage. A chair will be selected and Yukon Pacific Corp. will continue its plan to new an all-Alaska LNG project.

Information on members

The board members are:

• Warren Christian of Anchorage is executive vice president of ASRC Energy Services, and previously was president and general manager of Houston Contracting. He has more than 20 years of experience in the construction and oil field services industry.

• David Cuddy of Anchorage is a lifelong Alaskan and has earned an economics degree and an Masters of Business Administration. Cuddy has worked as a banker for 22 years, served as a chief financial officer for an Internet company and served one term in the Alaska House of Representatives.

• Bob Favretto of Kenai owns car dealerships in Kenai, Soldotna and Juneau. He is a member of the Alaska State Chamber of Commerce, the Cook Inlet Pipeline Terminals Group and chairman of the City of Kenai Economic Development Committee.

• Scott Heyworth led the public campaign for the passage of ballot measure 3, which called for the formation of a natural gas authority and the appointment of its members by the governor. Heyworth is an Anchorage longshoreman.

• Naimi, who has represented the Saudi government in negotiations with foreign oil companies — including Texas-based ExxonMobil, Royal Dutch/Shell and BP — have been seeking to invest $25 billion in gas-development and desalination projects in exchange for access to Saudi Arabia’s vast gas fields.

• Dan Sullivan of Anchorage served for nearly a decade with Marathon Oil and Phillips Petroleum in Nikiski. He is experienced with global marketing strategies for liquefied natural gas. Sullivan sits on the Anchorage Municipal Assembly.

• Andy Warwick is a Fairbanks accountant who served as the commissioner of the Department of Administration under Governor Joy Hammond. Warwick also served in the Alaska State House of Representatives from 1971 until 1974 and was a member of the Committee on Oil and Gas Taxation.

Heyworth pleased with board

Scott Heyworth, the initiative organizer, told Petroleum News June 9 that he was very pleased with the board.

“It looks to me to be a phenomenal quality board and I’m sure that all the directors are good Alaskans with the aim to once and for all answer the question: is an LNG project viable for Alaska and the world,” Heyworth said.

The gas authority is not another study, he said: “This is a real project to put Alaskans back to work and fuel the Alaska and U.S. economies.”

Heyworth said that while he believes there is a market for Alaska LNG in the Far East, “I really think that California is one of our biggest potential purchasers. And I’m sure we’ll be working with the California Energy Commission to see if we can establish a relationship between California and Alaska to supply them with our gas.”

continued from page 16

DEAL

the official said.

He said Saudi Arabia will be working on developing the fields with other companies, but did not elaborate on which companies or what stage the negotiations were at.

ExxonMobil Corp. share prices slipped 24 cents to $37.16 on the New York Stock Exchange June 5 on reports that Saudi Arabia had pulled out of the project.

ExxonMobil spokesman Cynthia Langlands confirmed June 5 that company officials had been meeting and exchanging letters with Saudi officials, including Naimi, who has represented the Saudi government in negotiations with foreign oil companies — including Texas-based ExxonMobil, Royal Dutch/Shell and BP — and have been seeking to invest $25 billion in gas-development and desalination projects in exchange for access to Saudi Arabia’s vast gas fields.

The project, announced in 2001, would represent the biggest opening of the Saudi oil and gas industry to outsiders since the 1970s.

ExxonMobil, which has a long history of operating in Saudi Arabia and has invested heavily in its oil-refining and petrochemical industries, had been picked to lead the $15 billion development in South Ghawar — the largest of the projects — and a smaller project near the Red Sea.

—THE ASSOCIATED PRESS

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LADYFERN

(now Duke Energy) suddenly lost more than 30 percent of its required volume. At the time, under total regulation, Westcoast did all the contracts for export sales and ran the main gas transmission line through central British Columbia, connecting with U.S. markets through Sumas, Wash.

The Ladyfern problem, fortunately, won’t cast the same long shadow. British Columbia’s productive capacity has already made up for the decline, and is expected to keep growing.

“If you look at drilling success, in the last six months, a lot of it has been on the B.C. side of the border,” says Molyneaux. “A growth of some of the best operators in the world. And 5 percent over next five years looks doable. Northeast B.C. will be very active for quite a while yet.”

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GIL

North mine, the shuttered Ryan Lode mine about 30 miles away near Estar and grasses root on federal-controlled land just southwest of the Fort Knox deposit.

It’s all part of an effort to keep the mill operating at its annual rate of 17.7 million tons of ore, producing a little less than 410,000 ounces of gold a year.

Based on existing geological work, the Fort Knox gold deposit will be mined out in 2010, Dye said, although it could be extended by successful exploration.

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HEALY

ty.

In past years, the two groups debated potential fixes for the plant, with Golden Valley insisting a full retrofit was necessary and AIDEA unwilling to take on more debt.

Additional federal funds of up to $125 million for the plant were authorized last year, with appropriation expected this budget cycle, Haugen said.

“It’s good to have that funding in place,” he said. “It’s probably the brightest star on the horizon.”

As owner of the facility, AIDEA has spent about $9 million a year on the Healy plant since construction was completed, according to a former project manager. That includes debt payments on the bonds and about $3 million a year to keep the plant in standby mode.

—PATRICIA JONES, Petroleum News Contributing Writer

By KRISTEN NELSON

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LADYFERN

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### Companies involved in North America’s oil and gas industry

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

### Business Spotlight

**Era Aviation**

Operating for 55 years in Alaska, Era is also based in Reno, Nevada and Lake Charles, Louisiana, with emphasis on providing helicopter support to the oil and gas industry. Other activities include flightseeing and construction, seismic, geophysical/geotechnical research, firefighting and fish and wildlife survey support. Era’s fleet wing division offers scheduled and charter flights throughout Alaska.

Kaye Benner is executive assistant to vice presidents Bryan Blahna and Lash Laru. Experienced gained from working in local law firms and BP’s legal department helps Kaye meet challenges facing the aviation industry. New responsibilities include assisting with corporate marketing. Her hands are always busy juggling a full-time job and full-time life. With five children and two grandchildren, no surprises there!

Kaye Benner

**Alaska Cover-All LLC**

Alaska Cover-All tells metal framed, fabric-covered buildings ranging from 18 to 270 feet wide and any length throughout the state. Last year the firm hired Henry Brown as project manager and began constructing an 8400 sq. ft. warehouse and storage yard on East 66th in Anchorage to better serve customers.

Alaska-born Paul F. Nelson is owner/manager, opening the dealership in 1998 with partner Jim Protzman. He has owned Nelson Company for 28 years and worked in construction and gold mining. The gold mining venture—four years as a percentage paid worker—was not too lucrative. “I never worked so hard, so long, for so little,” he says.

Landscaping, building projects, restoring old cars, and weekends at their cabin keep Paul and his family happily occupied.

Paul F. Nelson, owner/manager
OCCUPY

Paul Roehl, vice president of land and development for Bristol Bay Native Corp., told Petroleum News.

The corporation has developed a resolution in favor of immediate exploration and development of the outer continental shelf North Aleutian Basin sale 92 area, which went to bid in October 1988 and garnered $96 million in bids for 23 leases totaling 122,000 acres. The March 1989 Exxon Valdez oil spill intensified opposition to the OCS 92 sale, which was eventually cancelled and the bid proceeds returned to the oil companies. Currently the OCS 92 area is under a development moratorium, and the U.S. Minerals Management Service won’t revisit it until 2011.

The corporation would like to see the moratorium lifted early, to create high-paying, rewarding jobs for the people of the region, particularly given recent disastrous commercial salmon seasons.

Salmon not enough

“Salmon alone can’t support the region anymore,” said Greg Briesch, senior geologist with Bristol Environmental & Engineering Services Corp., a subsidiary of Bristol Bay Native Corp.

The OCS 92 lease sale occurred at a time when Bristol Bay salmon brought as much as $2.60 per pound, while oil sold for only $17.20 per barrel, Roehl said. Today salmon brings only about 40 cents per pound. In 1986, the value of oil and gas in the bay was seen as insignificant, compared to the rich value of the fishery.

U.S. Rep. Don Young, in a 1995 press release supporting a continued moratorium on leasing in the bay, summed up the thinking of his constituents in the region at the time.

“All told, the commercial fisheries have an average annual wholesale value approaching $1 billion and employ more than 10,000 Americans. The area of the Sale 92 leases is also the heart of a major migration, staging and feeding area for numerous marine mammals, seabirds and waterfowl,” Young said. “The commercial and intrinsic value of the region’s marine life is too great to put at risk for the small amount of estimated recoverable oil reserves in the North Aleutian Basin.”

Today, however, economic realities dictate a fresh outlook.

“We have some ‘not in my backyard’ holdouts,” Roehl said. “But the younger generation is more progressive on oil and gas development.”

Another factor affecting the opinions of Natives on the oil versus fish question is the fact that there is less Native ownership of fishing permits in Bristol Bay than was the case in the 1980s. Many local fishermen, swayed by the fluctuations in the fishery, have sold their permits, Roehl said. Today, a large number of permits are owned by people who live outside the area, and outside the state.

On the other hand, Roehl said, the corporation is consistent that oil development be done in an environmentally sound manner, with maximum protection to the fishery resources.

“Culturally, spiritually, salmon are very vital to the region,” he said. “We must preserve fisheries.”

see OPPORTUNITY page 20

DOG says Bristol Bay intriguing

The Alaska Division of Oil and Gas is taking a fresh look at oil and gas potential in Bristol Bay. The division has received information from the local community and is doing some baseline assessment work on the geology of the area, he said. “We’re reevaluating the area in light of changes in geologic understanding, exploration and development technology and economic and market conditions. Successful development would provide substantial economic benefits to the region, including more affordable local energy.”

Myers said there was sporadic drilling in the area from the early 1990s through 1995. The state has a substantial land position on the onshore portion of the basin and could consider putting the area up for area-wide lease sale, he said.

While state land extends three miles offshore, the state is enjoined from allowing surface activity on submerged lands in the bay, so any oil or gas exploration or development surface activities would be limited to onshore areas only, said Jim Hansen, chief petroleum geophysicist and lease sales manager for the DOG.

State lands on edge of basin

State lands on the Alaska Peninsula are on the fringe of the North Aleutian basin, a prospective formation that underlies Bristol Bay.

“Basically, there is basin north of the Alaska Peninsula — a big sedimentary basin, on land to onshore area — to the northwestern half of the Alaska Peninsula between Katmai and Port Moller,” said Don Britzolara, DOGpetroleum geologist. Britzolara said oil seeps, noticed as early as 1903, have drawn people to the area. A total of 26 wells drilled on the peninsula itself, from the 1920s through the 1960s, and one offshore in the 1980s, didn’t find anything of consequence, Britzolara said, adding that seismic technology at the time the wells were drilled was quite primitive.

“What that area really needs to define these structures is modern seismic data to find the sweet spots out there,” he said.

The Alaska Peninsula is a volcanic arch that stretches 500 miles in length from the mainland to the beginnings of the Aleutian chain, and varies from 100 miles wide, to 25 miles wide near Port Mouiller. The volcanic activity makes exploration decay.

“The volcanic strata often have a bad effect on reservoir rock... certain minerals that come from volcanic rock can get into your reservoir rocks and basically plug up the porosity,” Britzolara said. “Also you’re dealing with a higher geothermal gradient — hotter rocks basically, and that can affect reservoir quality.”

Despite the challenges, the area looks intriguing, he said.

“In the last 10-20 years technology has really advanced, and our geologic understanding of Alaska has advanced,” Britzolara said. “It’s an area we need to take a look at; there could be treasure down there that we could have missed.”

—STEVE SUTHERLIN, Petroleum News associate editor
can transport 18 passengers with a crew of two. BP’s goal for the program, Beando said, is to come up with a safe, reliable and economical transportation mode that will serve Northstar all year long. This particular hovercraft design is quieter and less expensive to operate than previously tested models of hovercraft and BP intends to conduct sound tests this summer, he said. “We have not yet begun using the craft, but are hoping to put it to use sometime this month after securing Coast Guard clearance,” Beando said. BP also expects the hovercraft to offer schedule flexibility by not being as sensitive to certain types of bad weather — such as fog — where (air) helicopter transportation may not be possible. The hovercraft will be stored at West Dock and piloted by Crowley Marine personnel.

While investment in a pipeline may be a daunting prospect, Roehl and Beischer agreed that the need for a pipeline presents an opportunity as well. Should large-scale oil development take place in Bristol Bay, pipeline ownership might prove to be a good investment. Much is uncertain about the future of oil and gas development in Bristol Bay but the corporation is doing what it can to reduce the uncertainty. It has approached the state to fund a $450,000 Bristol Bay basin analysis, to be performed by the Arctic Energy Technology Development Laboratory at the University of Alaska Fairbanks. The study would pull together old well logs and other documents, and digitize what seismic data exists on the area. Additionally, records of oil exploration in the region are in scattered locations. It is hoped that the availability of the data in a computerized database will stimulate other industry in the area. In addition to direct economic benefits of oil development spending, Roehl said the availability of local energy sources would stimulate other industry in the area. “There is a big need to reduce the cost of energy in Alaska,” Roehl said. “Low cost energy makes other mineral development possible.”

OPPORTUNITY

Pipeline needed

Should Bristol Bay yield large quantities of oil, producers will need a way to get the oil to market. Because Bristol Bay is shallow, it isn’t an ideal location for a tank loading facility. However, 50 miles away, on the south side of the Alaska Peninsula, lies deepwater access to the Pacific.

A pipeline is the obvious solution, Roehl says. “The pipeline might be expected to mean, due to the mountains and streams of the peninsula. More daunting, perhaps, is the need for storage and tanker facilities on the Peninsula. More daunting, perhaps, is the need for storage and tanker facilities on the Peninsula. A pipeline is the obvious solution, Roehl says. “The pipeline might be expected to mean, due to the mountains and streams of the peninsula. More daunting, perhaps, is the need for storage and tanker facilities on the Pacific side, a cost that has caused at least one large independent to pass on the idea for now.”

Forest Oil, which had once expressed some interest in the Bristol Bay region, told Petroleum News in June that it wasn’t interested in Bristol Bay because of other commitments, indicating it was already exploring in a non-producing, frontier basin in Alaska, the Susitna.

“It’s a huge risk for any oil company to take a chance,” said Beischer.

BOLD before the House Energy and Commerce Committee. Their message: natural gas is in short supply long term and the current, astronomically high prices aren’t coming down anytime soon.

Windfall profits on natural gas shortage

Richard Neufeld, British Columbia’s minister of Energy, has a glow in his eyes about all this. Just wait ’til those Californians find out that the province they are accusing of ripping them off on natural gas exports is now making even increasing windfall profits on the natural gas supply shortage. This is the fact is, British Columbia has in the last couple of years become the key to Canada’s ability to maintain its approximately 15 percent share of the growing U.S. gas market.

Last week, the Alberta Energy and Utilities Board issued its annual energy forecast and is predicting that, beginning next year, Alberta gas production will begin declining at a rate of 2 percent per year for a decade or more. This despite a record annual drilling rate of 10,000 wells per year.

British Columbia, on the other hand, is expecting its natural gas production to grow by 2 percent a year for the same period. Recent discoveries like Ladyfern, Greater Sierra (EnCana), and Monkman (Talisman) are clear indications that British Columbia’s relatively under-explored geography has some surprises in store.

“There’s huge potential in B.C.,” says Energy Minister Neufeld. “Oshoro and offshore, we’re estimating (a resource of ) 115 trillion cubic feet of (conventional) gas, and 89 tcf of coal bed methane resources. We produce 1.1 tcf per year now, and that’s with today’s technology.”

Window of opportunity

Eventually, the United States will build the Alaska natural gas pipeline and increase shipments of liquefied natural gas from either the Middle East or Asia. But that will take another 10 years, and in the meantime British Columbia hopes to seize a window of opportunity with its own resources.

The province’s energy ministry is taking a short and long term approach.

In the short term:

• Last week, a series of royalty breaks and other incentives was introduced to spur more industry activity in the north-east. Producers will pay a lower royalty rate on production from marginal gas wells, and on the much riskier deep wells (where the potential elephants are found).

• In addition, major investments are being made in road construction to allow for environmentally safe summer drilling. British Columbia’s very short three month winter drilling season (rips could work only while the ground is in short-term, and the current mid winter is frozen) has always been seen as a big impediment to the development of the province’s energy resources.

For the longer term:

The Energy Ministry and the Geological Survey of Canada are jointly developing a series of updated geological reports on other areas of the province — such as the North Coast and Bowser basins and southeastern British Columbia — to show the industry. Ministry officials have already taken these reports (the ones completed anyway) to industry meetings in Calgary for input.

A very broadly worded request for proposals has been issued for energy projects province-wide.

“Ministry has been put together to focus completely on the controversial offshore potential.”

Royalty revenues and fees will rise

The rationale for all this is obvious. Based on high prices and increasing production, the Ministry is now forecasting that royalty revenues and fees from petroleum in the next fiscal year will hit $7.8 billion, and quite probably go even higher.

Neufeld and Finance Minister Gary Collins laid all this out in Calgary last week. “We’re seeing some significant changes in the industry,” he said. “And we’re hoping to put it to use sometime this summer.”

This should be music to the ears of U.S. legislators, now coming to grips with the realizations that today’s high prices are here to stay. At a Congressional panel hearing the week of June 10, the sorry state of the natural gas supply situation was given a full airing. The Contradiction in U.S. energy policy

Federal Reserve Chairman Alan Greenspan told the Congressmen that the United States needs to address a serious contradiction in its energy policy.

A contradiction that has been a major contributor to the current crisis is to reach an agreeable tradeoff between environmental and energy concerns for decades,” he said in his testimony. “…it is essential that our policies be consistent. For example, we cannot, on the one hand, encourage the use of environmentally desirable natural gas in this country while being conflicted on larger imports of LNG. Such contradictions are resolved only by debilitating spikes in price.”

Tanzin: storm brewing on horizon

Greenspan was asked if he had any answers for the short term supply shortages, and he shook his head. He pointed out that Canada would be hard-pressed to increase its exports (withstanding any great improvements in British Columbia production).

For the future, Greenspan looks to a significant increase in LNG imports, and access to Alaska natural gas.

In earlier testimony, committee chairman Rep. Billy Tauzin, R-La., said government was to blame for what he termed a potential “train wreck.”

If the train wreck occurs and natural gas prices skyrocket and shortages occur, who will be at fault? The producer? The consumer? Or perhaps the federal government? We see a storm brewing on the horizon.

One answer, according to Tauzin and industry representatives would be for the federal government to allow oil and gas development on more public lands, a move that many Democrats on the committee oppose.

Energy Information Administration head Guy Caruso told the committee that natural gas storage was at the lowest level since the mid 70s, with only 263 billion cubic feet now injected. That’s 28 percent below the five-year average. An unusually hot summer might make it nearly impossible to get up to the 3 trillion cubic feet consider essential for winter.