Petroleum news

Vol. 9, No. 21 • www.PetroleumNews.com

North America's source for oil and gas news

Week of May 23, 2004 • $1

page 7 Deal-minded independent shells out $1.1B in largest deal ever

BREAKING NEWS

NORTH SLOPE, ALASKA

Cracking the nut

Armstrong Oil's Stu Gustafson has designed a production system that lowers the cost and environmental risk for North Slope development

By KRISTEN NELSON & KAY CASHMAN

Petroleum News editors

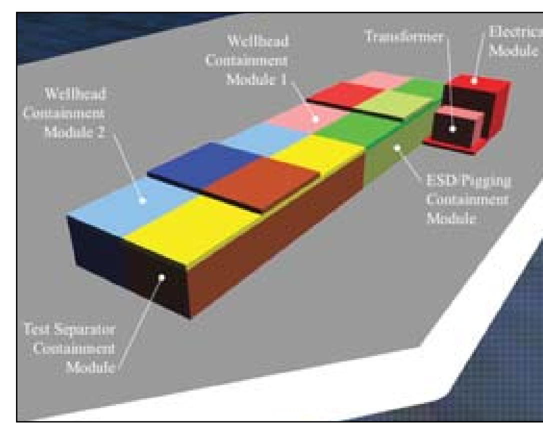
Some refer to it as a paradigm shift; others say it is a game changer. Everyone agrees it has the potential of cracking the nut for Alaska's North Slope in the same way new technology made the North Sea's oil fields economic to produce in 1971.

'It' is a production system for onshore and near-shore that cuts the cost of the drill site almost in half and drops the chance of an oil spill to close to zero, says the architect of the new system, Stu Gustafson, operations vice president for Armstrong Oil and Gas, the Denver independent that attracted Pioneer Natural Resources and Kerr-McGee to Alaska as partners in 2002 and 2003, respectively. Both Pioneer and Kerr-McGee have since drilled exploration wells and announced oil discoveries on North Slope prospects identified by Armstrong.

JUDY PATRICK

Stu Gustafson, operations vice president for Armstrong Oil and Gas

Lowering exploration and production drill site costs would allow explorers to go after "smaller" fields — i.e. 50 million barrel fields instead of 100 to 300 million barrel fields, a mechanical engineer who has worked closely with Gustafson to fine-tune the production system design told Petroleum News in mid-May.



COURTESY ARMSTRONG OIL & GAS

Modular production drilling site will be entirely enclosed, and require half the Island.

"With this design you no longer need to find a 100-300 million barrel field on the North Slope. You can look at the 50 million barrel field, which is something the independents can … develop more economically than the majors," Darcee Adam said. The bonus? When you're looking for smaller fields, you stand a chance of finding a 300 million barrel field.

see **CRACKING** page 13

ALASKA

Cook Inlet sale a burner

Alaska lease sales bring in $2.9 million, $2.7 million from sale of 72 tracts in Cook Inlet Basin and five tracts in Brooks Range Foothills

By KRISTEN NELSON

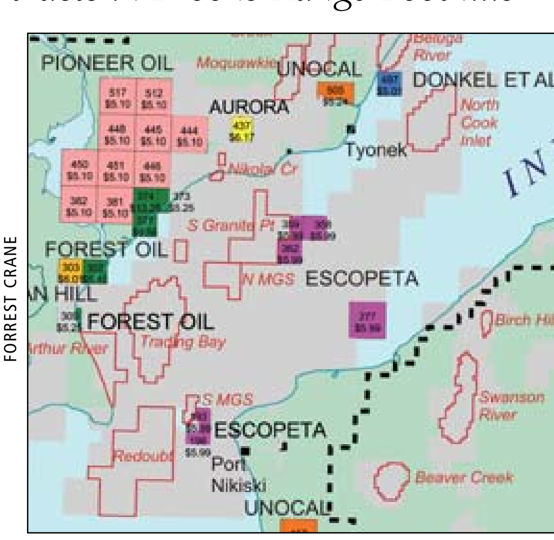
Petroleum News Editor-in-Chief

The state of Alaska took in $2,876,720.16 at two areawide lease sales May 19: $154,656 for five tracts in the North Slope Foothills lease sale and $2,722,084.16 for 72 tracts in the Cook Inlet lease sale.

It is the most successful Cook Inlet lease sale in 15 years, Alaska Department of Natural Resources Deputy Commissioner Marty Rutherford said before the bids were opened. This sale, Rutherford said, "marks the seventh year" of the Alaska areawide oil and gas leasing program, which began in 1998. The state has leased nearly 3.7 million areas in 18 areawide lease sales, "and after today, we anticipate exceeding $100 million in bonus bids" from the areawide sale program, she said.

FORREST CRANE

"This is the most interest we've received in a Cook Inlet sale since Sale 49 which was held in 1986." —Mark Myers, Alaska Division of Oil and Gas director



See full size map, page 23

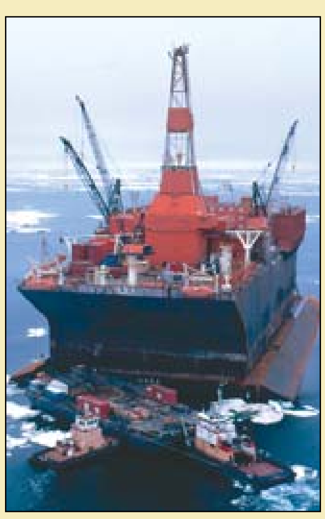
She also welcomed Pioneer Oil Co. of Lawrenceville, Ill., to Alaska — the company took 27 of the 28 Cook Inlet tracts on which it bid — and noted that "independents play a very vital role in exploration in Alaska, all the way from the Beaufort Sea to the Cook Inlet, and you've been growing in numbers, which we're very pleased about." (See related story on Pioneer on page 4.)

see **SALES** page 20

Devon tests new Arctic well kill system, blowout preventer could extend drilling season

Along with entering the regulatory phase of its plans to reactivate exploration of Canada's Beaufort Sea, Devon Canada is working on new technology that could both reduce the risks and extend the drilling season in the Arctic.

The company has contracted with a Houston-based firm to build and test what it calls a second-generation BOP (blowout preventer) that it hopes it can convince Canada's National Energy Board is the equivalent to a relief well.

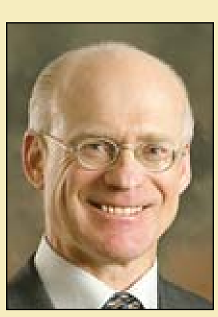


JUDY PATRICK

The SDC is one of three drilling platform options being reviewed by Devon Canada for its Beaufort Sea exploratory program.

see **DEVON** page 6

Natural gas set to displace oil on world stage



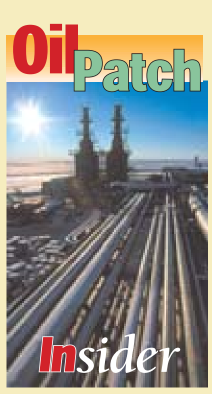
EnCana CEO Gwyn Morgan

With so much attention on crude oil's charge into the pricing stratosphere, natural gas has been relegated to the background despite making its own rally.

By mid-May on the New York Mercantile Exchange gas for June delivery hit a six-month peak of $6.40 per million British thermal units — a gain of about 30 percent in six weeks — as traders started eyeing a possible summer

see **STAGE** page 6

So what's all the fuss over $40 oil?



AS THE WORLD REELS from oil prices of more than $40 a barrel, consumers squawk about what they pay at the gas pumps and politicians go into a tizzy, it's worth remembering that the current values are chicken feed alongside those of 25 years ago.

Earl Sweet, an assistant chief economist at the Bank of Montreal, told the Globe and Mail that "we're very far away from oil shock territory."

He was referring to the late 1970s and early 1980s when the

see **INSIDER** page 20

● BRITISH COLUMBIA

Montana senator issues ultimatum

Baucus opposes plans for coalbed methane, coal mining in southeastern British Columbia

By GARY PARK
Petroleum News Calgary Correspondent

United States Senator Max Baucus has tossed some spikes on British Columbia's road to coalbed methane riches.

The senator from Montana is trying to draft U.S. Secretary of State Colin Powell for a campaign to protect the wilderness area of Montana's Flathead Valley, 16 years after he successfully led a crusade to stop coal mining in British Columbia's portion of the valley.

In a recent letter, Baucus told Powell that plans to offer coalbed methane leases and open a coal mine within two years in southeastern British Columbia could endanger Glacier National Park, the Flathead River system and the "clean, clear waters of Flathead Lake (that) serve as the backbone of the economy of northwestern Montana."

He said that if the British Columbia government pushes ahead with its plans, "They are asking for a fight."

Baucus reminded Powell that in 1988 the International Joint Commission, a U.S.-Canada advisory body that oversees cross-border water issues, rejected a proposed coal mine in the British Columbia Flathead Valley because of the downstream pollution that the project would cause.

He asked whether an application by Cline Mining for a coal mine would fall under the same ruling.

Plans for coalbed methane leasing a concern

As well, Baucus said he was concerned about the British Columbia government's intentions to offer leases for coalbed methane projects that can produce large volumes of saline water.

The city council of Fernie, in southeastern British Columbia, welcomed the U.S. interest because the community's concerns have been ignored by the provincial government.

The council recently asked the province to delay any action on coalbed methane tenures until there had been a full assessment of the environmental, economic and social consequences.

Bill Bennett, a government member of the British Columbia legislature, said he is convinced coalbed methane can be extracted without harming the environment.

Meanwhile, Derek Doyle, chairman of the British Columbia Oil and Gas Commission, told a Canadian Institute gas symposium in Vancouver May 12 that the province is moving in a "careful, cautious" way towards coalbed methane development.

He said that not only is there no coalbed methane production in the province "we don't have any development that's in a feasibility stage."

Commission would issue approvals for experimental work

While the commission is ready to issue approvals for experimental work, he said any companies that have their eyes on commercial projects will have to provide the regulator with a "detailed analysis of the operation."

Doyle rejected a plea by Mark Simpson, coalbed methane manager for Nexen, for British Columbia to follow Alberta's lead and conduct public meetings across the province to develop coalbed methane regulations.

He said British Columbia is already organized to hold open houses and meet with groups, individuals and landowners on specific coalbed methane projects and has extended its regulations to include coalbed methane and related water disposal.

Doyle said that under new legislation, water extracted during coalbed methane production must be injected into water that is already more polluted, or safely disposed of at the surface.

The commission's objective is to ensure that industry is responsible for healing and restoring the land.

Of the companies pursuing coalbed methane interests in British Columbia, Petrobank Energy and Resources plans on taking the first step towards commercial production by drilling a well this July near Princeton, in southwestern British Columbia, on a 12,000-acre basin that it believes could have a recoverable resource of 161 billion cubic feet.

Trident Exploration has identified potential coalbed methane development on two properties covering 32,000 acres in northeastern British Columbia. ●

QATAR

Anadarko Petroleum signs agreement to explore large block offshore Qatar

Houston-based Anadarko Petroleum has signed an oil and gas exploration and production sharing agreement with Qatar Petroleum for Block 4 offshore Qatar, Anadarko said May 18.

The 3,132 square-kilometer contract area is some 40 kilometers from the northern coast of Qatar and lies adjacent to the Anadarko-operated Al Rayyan oil field on Block 12.

The terms of this agreement call for an initial five-year exploration phase during which Anadarko, in partnership with Qatar Petroleum, will undertake a work program comprising technical studies, seismic reprocessing, acquisition of 2-D and 3-D seismic data and exploratory drilling. Anadarko holds a 100 percent interest in the block.

"The block is situated within some of the world's most prolific petroleum systems, and has remained relatively unexplored for the last 30 years," said Jim Emme, Anadarko's vice president of exploration and business development.

Anadarko acquired its position in Qatar through the purchase of Gulfstream Resources in 2001. In 2002, with the purchase of BP's interests in Blocks 12 and 13 in Qatar, Anadarko increased its working interest from 65 percent to 92.5 percent and became the operator.

Anadarko also holds a 49 percent interest in Block 11, operated by Wintershall. With the addition of Block 4, Anadarko will hold interest in over 1.5 million gross acres in Qatar.

—RAY TYSON, Petroleum News Houston correspondent

JUNEAU, ALASKA

Oil tax committee plan dies on last night of Alaska legislative session

The Alaska House and Senate disagreed on a proposed study of the state's oil and gas tax and royalty structure, killing off an effort to look at Alaska's competitiveness for worldwide investment dollars and whether the state is getting its fair share at high oil prices.

House members had voted overwhelmingly to set up a special joint committee to look at the issues during the interim and report back to lawmakers for the 2005 session. But the Senate dropped the provision for a special committee, reduced the work assignment and eliminated funding for the effort.

The measure died on the last night of the session May 11, when disappointed House members refused to accept the Senate's changes.

The measure's sponsor, Rep. Cheryll Heinze, R-Anchorage, said House members wanted to show the public they are doing their job by responding to people's questions about whether the state is getting its fair share of oil revenues when crude is selling in the upper $30-per-barrel range.

And the House also wanted to show the oil and gas industry that lawmakers are aware of the high costs of doing business in the state and the need to remain competitive at attracting investment dollars for exploration and production, especially when oil prices are low. "We were trying to be proactive" she said.

"This (industry) is 85 percent of our tax base," Heinze said, and is worthy of a thorough and comprehensive review by a special committee and international consultants to determine if Alaska is doing the best it can.

Not intended as a tax increase committee

The House did not view the undertaking as a tax increase committee, as opponents feared, Heinze said.

Whatever the House intended, the industry came out strongly against the bill.

House Concurrent Resolution 39 passed the House on a 32-5 vote May 7, less than

see **PLAN** page 4

Issue Index

Petroleum news

North America's source for oil and gas news

Dan Wilcox	CHIEF EXECUTIVE OFFICER	
Mary Craig	CHIEF FINANCIAL OFFICER	
Kay Cashman	PUBLISHER & MANAGING EDITOR	
Kristen Nelson	EDITOR-IN-CHIEF	
Gary Park	CALGARY CORRESPONDENT	
Larry Persily	GOVERNMENT AFFAIRS EDITOR	
Ray Tyson	HOUSTON CORRESPONDENT	
Steve Sutherlin	ASSOCIATE EDITOR	
Wadeen Hepworth	ASSISTANT TO THE PUBLISHER	
F. Jay Schempf	CONTRIBUTING WRITER (HOUSTON)	
Alan Bailey	CONTRIBUTING WRITER	
Allen Baker	CONTRIBUTING WRITER (OREGON)	
Pat Healy	CONTRIBUTING WRITER (HOUSTON)	
Paula Easley	COLUMNIST	
Patricia Liles (formerly Jones)	CONTRIBUTING WRITER (FAIRBANKS)	
Judy Patrick Photography	CONTRACT PHOTOGRAPHER	
Firestar Media Services	DIRECTORY PROFILES	
Mapmakers Alaska	CARTOGRAPHY	
Susan Crane	ADVERTISING DIRECTOR	
Forrest Crane	CONTRACT PHOTOGRAPHER	
Steven Merritt	PRODUCTION DIRECTOR	
Tom Kearney	ADVERTISING DESIGN MANAGER	
Heather Yates	CIRCULATION MANAGER	
Tim Kikta	CIRCULATION REPRESENTATIVE	
Dee Cashman	CIRCULATION REPRESENTATIVE	

ADDRESS
P.O. Box 231651
Anchorage, AK 99523-1651

EDITORIAL
Anchorage
907.522.9469
Juneau
907.586.8026

EDITORIAL EMAIL
publisher@petroleumnews.com

BOOKKEEPING & CIRCULATION
907.522.9469
Circulation Email
circulation@petroleumnews.com

ADVERTISING
907.770.5592
Advertising Email
scrane@petroleumnews.com

CLASSIFIEDS
907.644.4444

FAX FOR ALL DEPARTMENTS
907.522.9583

Petroleum News and its supplement, Petroleum Directory, are owned by Petroleum Newspapers of Alaska LLC. The newspaper is published weekly. Several of the individuals listed above work for independent companies that contract services to Petroleum Newspapers of Alaska LLC or are freelance writers.

Petroleum News (ISSN 1544-3612) Week of May 23, 2004
Vol. 9, No. 21
Published weekly. Address: 5441 Old Seward, #3, Anchorage, AK 99518
(Please mail ALL correspondence to:
P.O. Box 231651, Anchorage, AK 99523-1651)
Subscription prices in U.S. — $52.00 for 1 year, $96.00 for 2 years, $140.00 for 3 years. Canada / Mexico — $165.95 for 1 year, $323.95 for 2 years, $465.95 for 3 years.
Overseas (sent air mail) — $200.00 for 1 year, $380.00 for 2 years, $545.95 for 3 years.
"Periodicals postage paid at Anchorage, AK 99502-9986."
POSTMASTER: Send address changes to Petroleum News, P.O. Box 231651 • Anchorage, AK 99523-1651.

● COOK INLET BASIN, ALASKA

Pioneer Oil eyes CBM development in Alaska

By KAY CASHMAN

Petroleum News Publisher & Managing Editor

A May 19 state lease sale for Alaska's Cook Inlet Basin drew winning bids of more than $2.7 million, as well as a major new player, Pioneer Oil Co. of Lawrenceville, Ill. (See related page 1 story.) The independent submitted high bids totaling $793,152 on 27 tracts in primarily two onshore lease blocks — one west of Knik Arm, across from Anchorage, from north of Point MacKenzie to southwest of Wasilla, and the other on the west side of Cook Inlet, inland from Trading Bay and west of Aurora's Nikolai Creek gas field.

Pioneer founder and president, Don Jones, a fourth-generation oilman who plans to visit Alaska for the first time in June, said his company was intrigued with the thickness of the coal seams in Alaska.

"We've been looking in the continental U.S. for the biggest reserves of natural gas … and it became apparent Alaska was an oasis of natural gas in several different formations," he told Petroleum News in an interview by phone following the sale.

"We took the leases for coalbed methane. Our intention is to explore and then exploit (produce) them."

Jones became interested in Alaska after a presentation from John Mackey, a consulting geologist his company frequently uses to find new prospective conventional and unconventional gas properties. Mackey, who is based in Bloomington, Ind., recently spent time in Alaska, researching the geology.

"I was amazed by the natural resources in Alaska. … There are tremendous gas reserves up there; not only where we took leases but farther north," Jones said.

Pioneer Oil has "worked with coals in Indiana, Illinois and Kentucky where you might have 35-40 feet of combined thickness. … At 3,000 feet in Alaska you have 400 feet combined footage of coal. … The farther north you go, the thicker they get. … And there is definitely a market for the gas up there," Jones said.

"I feel Alaska has been overlooked by the producers here in the continental U.S. … I feel like we're just the first of many to come."

Not looking at heavily populated areas

When asked about Evergreen Resources, which has been beset with political and some permitting problems as a result of a deluge of complaints from private landowners in Southcentral Alaska, Jones responded, "I thought it was most unfortunate for Alaska that Evergreen would pick an area that was heavily populated, especially when it appeared they could do the same thing in less populated areas. We took our leases away from populated areas."

Jones said he intends to bring his technology, integrity and sensitivity to the environment to Alaska.

"We hope to be welcomed by the locals there. We'll do everything aboveboard, like we do down here."

Coming to Alaska in June

Jones was leaving for Africa the day after the Cook Inlet lease sale, but he intends to visit Alaska after he returns on

see PIONEER page 22

continued from page 3

PLAN

48 hours after it was introduced to lawmakers. The Senate Resources Committee three days later rewrote the measure, which passed the Senate 16-4 on the Legislature's final day but the House — with 38 minutes left before the midnight adjournment deadline — voted 19-20 to reject the Senate version and the measure died.

Heinze, a freshman lawmaker, said the joint committee also was part of the end-of-session deal that House Republican leaders offered minority Democrats to gain their support for budget votes. The Democrats have been pushing for changes in the state's oil and gas production tax formula to give the state a larger slice when prices are high.

Representatives of the Alaska Oil & Gas Association, Resource Development Council of Alaska and Alaska Support Industry Alliance testified against the measure in the Senate committee.

Proposal worried industry

"This is causing a lot of telephone calls back and forth," and is sending a bad message to the industry, said Judy Brady, executive director of the oil and gas association.

"HCR39 singles out the oil and gas industry," said Larry Houle, general manager of the Alliance.

After adopting the amended resolution, Senate Resources Committee Chair Scott Ogan said he would eliminate the $575,000 in state money requested for one staff member and consultants for the proposed Alaska Royalty and Revenue Committee.

"The chairman will zero out the fiscal note," the Palmer Republican said of the funding request. "It's my prerogative as chairman sometimes."

The committee version would have assigned the job to the Legislature's Budget and Audit Committee, without the instructions requested by the House that the special committee hold public hearings and, if necessary, have the ability to review confidential information.

Though the legislative resolution failed to pass, the Budget and Audit Committee voted May 18 to spend up to $50,000 to purchase a consultant's report expected later this year on the economics of exploration for oil and gas in more than 60 countries and Alaska.

Lawmakers subscribe to Wood Mackenzie report

The report, by global oil and gas consulting firm Wood Mackenzie Ltd., will look at upstream economics, exploration success rates, average discovery sizes, finding and development costs and government takes. It will be an update of a similar 2002 report.

"It's good timing for the Legislature to be looking at those issues," said Committee Chair Rep. Ralph Samuels, R-Anchorage.

Meanwhile, the Alaska Department of Revenue continues its review of the state's oil and gas production tax incentive called the Economic Limit Factor, or ELF, intended to reduce taxes on smaller or older fields. Dan Dickinson, director of the Tax Division, told legislators last month the governor had asked the department to review the tax formula.

"You look at the ELF formula and you ask, is it perfect?" Dickinson said in an interview last month. "Does it strike the exact right balance?" he asked, between encouraging future development and providing a fair share of revenues to the state.

He declined to provide specific details of the Tax Division's ongoing review of the production tax formula.

—LARRY PERSILY, Petroleum News government affairs editor

● COOK INLET

Storing Cook Inlet gas steadies production, price

Basin's natural gas demand varies seasonally for residential and utility needs, while industrial users take a steady stream of gas

By KRISTEN NELSON

Petroleum News Editor-in-Chief

The Cook Inlet basin is going to need natural gas storage — probably on the order of five times the amount available today — to meet demands during cold weather, ensuring energy and well productivity by allowing for steady production.

This is a result of a transition in the Cook Inlet natural gas market "from a state of abundance to a state of decline," said University of Alaska Anchorage finance and economics student Ben Vandorn, who presented results in Anchorage May 18 of a semester-long research project he did on a scholarship from the Anchorage chapter of the International Association for Energy Economics. Vandorn is an intern in the commercial section of the Alaska Department of Natural Resources Division of Oil and Gas.

Storage "is essentially an underground reservoir that's used to bank gas for use at some later date," said Vandorn. Natural gas storage is common in the Lower 48, and while there are many types, there are "only two configurations: a base load system or a peak load system." Base load stores gas for response to seasonal demand, while peak load responds to "more instantaneous shifts in supply or demand," Vandorn said. The difference is how fast you can fill the reservoir and then empty it to deliver the gas: peak load systems are designed to respond quickly.

Storage is traditionally done in the summer when prices are lower and gas is more plentiful.

Base gas vs. working gas

But not all of the gas stored can be sold. The most common types of storage require base gas which remains in the reservoir and maintains pressure, he said. What is sold off is called working gas.

Most storage in the United States is in depleted reservoirs, aquifers and salt caverns. Not all of these, Vandorn said, would be applicable to Cook Inlet.

"Depleted reservoirs are the most common method of storage," he said. Depleted oil or gas reservoirs are filled with gas, and while they are the least expensive type of storage to develop, deliverability is poor. "They're typically designed for one storage cycle per year — one fill up and one depletion," Vandorn said.

Aquifers, more expensive to develop, are "typically designed for five-plus storage cycles per year, which makes them a better candidate to respond to the peak delivery issues," he said. An aquifer is a naturally occurring, permeable and porous rock formation that contains water. Because there has never been gas in the aquifer, base gas — to provide reservoir pressure — must be purchased, adding to the development expense.

Vandorn said that based on volumes of gas used in the Cook Inlet area he believes that 5 bcf of working gas storage is needed, not necessarily one big facility, but more likely "several smaller storage facilities such as Swanson River."

Salt caverns are developed by flushing them with water to dissolve and remove the salt, making them expensive to develop. But, he said, salt caverns require only small amounts of cushion or base gas, and have high deliverability — "they can be cycled full to empty upwards of 50 times a year."

Liquefied natural gas is also used for gas storage, particularly to meet peak needs, and a "spin-off of LNG is a refrigerated cavern" which is mined out of bedrock and filled with cooled gas. The gas isn't cooled enough to form LNG, but the volume is reduced. Refrigeration requirements and mining make refrigerated caverns an expensive alternative, but, like LNG, the caverns have high deliverability.

And in the research phase: gas hydrates to store natural gas. Vandorn said research at "Mississippi University determined that gas hydrate storage would be economical to use if more than 54 cycles per year occurred and would actually be less expensive per cycle than depleted reservoirs if more than 100 cycles per year were used." That option, however, is not yet being used commercially, he said.

The majority of natural gas storage in the United States is depleted reservoirs and the majority of that storage is in heavy consuming areas — the Midwest and Northeast.

One depleted reservoir in use in Cook Inlet

Cook Inlet has one gas storage facility, Vandorn said, run by Unocal at Swanson River, a depleted reservoir with more than 1 billion cubic feet of storage capacity. Unocal started injecting gas in 2001 to provide peak shaving service to Enstar. The facility tops out at about 1.2 bcf, he said, including both the base gas and the working gas.

In addition, Cook Inlet has additional natural gas available on a seasonal basis from the Agrium fertilizer plant. The fertilizer plant and the ConocoPhillips-Marathon LNG plant, both at Nikiski on the Kenai Peninsula, are Cook Inlet's two large industrial gas users. Vandorn said the fertilizer plant provides "production backstop" to natural gas deliveries in Southcentral Alaska. In the winter months, when natural gas demands for home heating and power generation peak, gas going to the Agrium plant can be curtailed. Because of declining gas supplies, however, Agrium has said it may be forced to close the plant.

"With the potential plant closure on the horizon, this means the removal of this production backstop, and this could create even more of a need for additional backstop capacity, i.e. storage," Vandorn said.

Values of storage

Additional storage for Cook Inlet gas "could provide for steady production year round," he said. "It's unreasonable to expect that we should be able to shut in wells to reduce the amount of production. With the aging climate of the Cook Inlet fields it's difficult to get wells back on line and it's very important that we're able to produce at full steam year round."

With storage available, production that isn't immediately used could be stored for needs in the winter.

Storage would also "help to define price" for natural gas in Cook Inlet, Vandorn said, because "it's expensive to develop storage and therefore there is going to be a premium paid for gas that comes out of storage or when storage gas is used to meet peak demand."

Comments from the audience after the presentation indicated an expectation that storage might add a dollar per thousand cubic feet to the cost of natural gas.

Vandorn said that based on volumes of gas used in the Cook Inlet area he believes that 5 bcf of working gas storage is needed, not necessarily one big facility, but more likely "several smaller storage facilities such as Swanson River." Enstar delivery swings range from 150 million cubic feet a day to more than 250 million cubic feet a day, he said, and the 5 bcf estimate is based on the premise that the Swanson River storage can deliver some 10 million cubic feet a day for 80 days, "not enough gas to ease peak deliveries here in the basin" especially if a long cold spell were coupled with other fuel emergencies or with field problems such as loss of a compressor.

Who would develop storage? Both Unocal and Marathon are researching additional storage capacity, he said, although in the Lower 48 it is typically interstate pipeline companies that own and operate storage facilities, which would make Enstar a likely candidate in Cook Inlet. ●

CORRECTION

A story about Marathon Oil's Cook Inlet activities in the May 16 issue included a reference to ConocoPhillips' gas production from the Beluga field. ConocoPhillips also produces natural gas from the Tyonek platform at the North Cook Inlet field

continued from page 1

STAGE

shortage.

The combination of a dry winter that could start to cut into hydroelectric power generation is sending jitters through the ranks of traders, given forecasts of a blistering summer, especially in California.

It also partly explains the buying spree for U.S. natural gas properties over the last month when premium values were attached to the reserves, reflecting a widely held view that gas supplies will remain tight until at least 2008 when the first significant wave of liquefied natural gas imports is expected, as well as the sharp rise in finding and development costs.

In its $2.7 billion offer for Tom Brown, EnCana paid an estimated $14 per barrel of oil equivalent for U.S. Rockies gas reserves, leaving in the lurch Kerr-McGee's $3.4 billion stock-swap takeover of gas producer Westport Resources, which was calculated at $11.90 per boe of reserves.

Those prices explain why EnCana Chief Executive Officer Gwyn Morgan emphatically believes that North America faces a gas squeeze over the next four years or longer.

Peter Odell, a professor at Erasmus University in the Netherlands, told an energy supply conference in Alberta in March that gas will outpace oil over the next 20 to 30 years, resulting in an end to the three decades when power over oil moved from producers to the OPEC nations.

Gas displacing coal and oil

It also promotes the notion that gas is displacing its old fossil fuel rivals — coal and oil — as the dominant source of energy in North America.

Peter Odell, a professor at Erasmus University in the Netherlands, told an energy supply conference in Alberta in March that gas will outpace oil over the next 20 to 30 years, resulting in an end to the three decades when power over oil moved from producers to the OPEC nations.

Currently gas and coal account for almost one-quarter each of world energy consumption, with oil claiming the other half.

Odell pointed out that it wasn't until recent times that explorers stopped throwing up their hands when they found gas.

For decades, millions of dollars of gas were burned off across North America by gas flares that once gave Turner Valley, southwest of Calgary, the title of Hell's Half Acre.

Odell said that gas will progressively displace oil in end uses such as transportation, setting up a "much more effective countervailing power against the power of OPEC. At that point gas producers should be in the driving seat."

Because of the massive infrastructure costs, the control over energy will be in the hands of a few companies, he said, noting that Royal Dutch/Shell is now poised to spend about $5.5 billion in the Persian Gulf state of Qatar to produce 140,000 bpd of gas-to-liquids output.

Among experts this is viewed as a vital step towards unlocking the world's stranded gas, especially the huge reserves in North Africa, Russia and the Middle East.

—**GARY PARK,** Petroleum News Calgary correspondent

continued from page 1

DEVON

Beaufort project leaders at Devon Canada told Petroleum News in a recent interview that the Alternate Well Kill system, if successful, could apply to drilling operations anywhere in the world.

Known as a Super, Shear & Seal BOP, the technology could stretch the Beaufort drilling season to 160 days from the usual 60 to 120 days available in the winter season and be employed on steel drilling caisson or landfast tender-assist drill units.

Well bore sealed with the touch of a button

Brian Kergan, Devon Canada's manager of frontiers development, said the BOP "allows us to close and seal the well bore" with the touch of a button and prevent any fluids escaping from the well.

The Canadian government requires drillers in the Beaufort to have "same-season relief well capability," which means a blowout must be killed in the same season to prevent any spills when the ice melts.

However, in the process of further tightening the drilling season by 40 to 60 days, the National Energy Board said it would accept an equivalent to a relief well.

Kergan said regulatory agencies will be invited to a test of the BOP in Houston later this year.

Three drilling platforms being considered

In an April filing with the National Energy Board, the company said it is considering three optional drilling platforms, none of which requires dredging support.

• Steel drilling caisson — A former crude oil tanker converted into a certified mobile Arctic platform and which has previously been used to successfully drill exploration wells in the Beaufort.

• Land-fast tender-assist drill unit — An engineered concept that, if constructed, would consist of an ice-strengthened steel caisson set directly on the sea floor and used as an operating base to construct a grounded ice pad. Once the pad is completed, a land rig stored on the LTD would be lowered to the ice to drill the well. The LTD would be custom-built and towed into the Beaufort.

• Ice island — A constructed, grounded ice pad used as a drilling platform. Equipment and materials would be transported by barge during the open-water season to a staging area, then delivered to the drill site during the winter by ice road.

The steel drilling caisson – i.e. SDC – is the same drill ship that a consortium of oil companies and the state of Alaska is looking at using to drill a stratigraphic test well in late 2004 offshore the Arctic National Wildlife Refuge in state waters. (See Petroleum News story archives at www.PetroleumNews.com for more information.)

—**GARY PARK,** Petroleum News Calgary correspondent

finance&economy

CANADA

Canadian executives predict $31 oil, robust stock markets

Canadian oil patch leaders are upbeat about the next three years.

They are counting on average oil prices of US$31 a barrel this year and US$28 over the next two, while predicting natural gas prices of C$5-$6 per gigajoule over the same three years.

They made their forecasts in the 12th annual survey of chief executive and chief financial officers by accounting firm Deloitte & Touche. The results were released May 17.

Richard Cooper, leader of the Canadian Energy Resources group in the firm, said the industry, although "often conservative" in its projections, has a solid record of assessing directional changes.

The executives are bullish on the stock market outlook, with almost 60 percent expecting the Toronto Stock Exchange's main energy index will rise 15 to 20 percent this year. Most expect further gains in 2005 and 2006 as well.

The market gains will also be accompanied by further consolidation, with an "overwhelming majority" of the respondents certain that the action will be concentrated in the income trust sector through trust mergers or independent producers converting to trusts.

More than 70 percent of those surveyed believe employment in the industry will rise this year, but 40 percent said they are having increasing difficulty finding engineers, geologists and other professionals to fill positions.

Despite those shortages, about 70 percent said they do not expect salaries to rise significantly, Cooper said.

—**GARY PARK,** Petroleum News Calgary correspondent

INTERNATIONAL

Worldwide rig economics take 4.5 percent dive in April

GlobalSantaFe's worldwide Score, or Summary of Current Offshore Rig Economics, for April was down an overall 4.5 percent from the previous month, the Houston-based drilling contractor reported May 17.

The Score compares the profitability of all current mobile offshore drilling rig day rates to the profitability of day rates at the 1980-1981 peak of the offshore drilling cycle.

In the 1980-1981 period, when Score averaged 100 percent, new contract day rates equaled the sum of daily cash operating costs plus about $700 per day per million dollars invested.

The Gulf of Mexico scored 37.4 for April, down 2.8 percent from the previous month's 38.4 but up 30.1 percent compared to the same period last year. The April Score also was up 51.2 percent versus five years ago.

The North Sea scored 40.3 for April, down 1.4 percent from the prior month's 39.7 but up 6 percent from a year earlier. April's Score was up 47.4 percent compared to five years ago.

West Africa registered a 48.5 Score in April, a decrease of 9.3

see **DIVE** *page 8*

● F O R T   W O R T H ,   T E X A S

XTO does it again

Acquisition-minded independent shelling out $1.1B in largest deal ever

By RAY TYSON

Petroleum News Houston Correspondent

Deal-minded independent XTO Energy, already approaching $800 million in acquisitions this year, has acquired another $1.1 billion in U.S. oil and gas properties, this time from ChevronTexaco.

Just weeks ago Fort Worth, Texas-based XTO announced the purchase of $340 million worth of U.S. properties from another major, ExxonMobil. Including various other acquisitions, XTO's total for the year is nearly $1.9 billion, far surpassing the company's original $650 million budget for full-year 2004.

"We're set for the next 12 to 18 months … but we keep looking," Bob Simpson, XTO's chief executive officer, said in a May 17 conference call explaining XTO's latest transaction, the company's largest ever.

The combination of ChevronTexaco and ExxonMobil properties would immediately increase XTO's overall production by a hefty 25 percent.

As a result of the ChevronTexaco acquisition, XTO said it is increasing its production growth target in 2004 to a range of 28-30 percent, up from earlier guidance of 20 percent. Production for 2005 was increased to a range of 18-20 percent, up from earlier guidance of 10-12 percent.

XTO now expects to produce daily 790-795 million cubic feet of natural gas in the 2004 second quarter, 870-875 million cubic feet in the third quarter, and 920-925 million cubic feet. Daily oil production is expected to average 17,500-18,000 barrels in the second quarter, 28,000-28,500 barrels in the third quarter, and 33,000-33,500 barrels. Daily natural gas liquids production is expected to average 6,000-6,500 barrels in each of the remaining three quarters.

Properties acquired in seven states

ChevronTexaco properties being acquired by XTO are located in seven states, with more than 90 percent of current production in Texas and New Mexico.

The acquired properties will expand XTO's operations in its Eastern Region, the Permian Basin and Midcontinent, while opening a new coalbed methane play in the Rocky Mountains and a new operating region in South Texas, XTO said.

The properties specifically contain proved reserves of 786 billion cubic feet of gas equivalent, 88 percent of which are proved developed, XTO said, adding that 48 percent of the reserves are oil. The acquisitions are expected to add 88 million cubic feet of natural gas per day and 14,000 barrels of oil per day to XTO's production base.

In the Permian Basin of West Texas and New Mexico, XTO said it is acquiring 80 million barrels of proved oil equivalent reserves in 16 counties. Net production from the properties is about 11,500 barrels of oil per day and 40 million cubic feet of natural gas per day. Primary producing fields in the area include Yates, Goldsmith, Eunice Monument, Fullerton and Puckett. The company said it expects to use its secondary recovery expertise to enhance operations and expand development upsides.

XTO Energy is also increasing its position in its Eastern Region with the purchase of 102 billion cubic feet of gas equivalent proved reserves in Franklin, Freestone, Limestone and Anderson counties of Texas and Claiborne Parish of Louisiana. Net production is about 13 million cubic feet of equivalent per day. The company anticipates upside oppor-

see **XTO** *page 8*

Want to know more?

If you'd like to read more about XTO Energy, go to Petroleum News' web site and search for these 2004 articles.

Web site: www.PetroleumNews.com

2004

- **May 9** XTO acquisitions near $800M for year
- **April 25** XTO Energy poised for large acquisition
- **April 11** XTO plans only offshore Cook Inlet well this year
- **April 11** Independents sparkle
- **March 7** XTO Energy, Carrizo Oil & Gas weigh in with record reserves
- **Feb. 29** XTO takes a bite out of Barnett Shale
- **Feb. 15** XTO projects double-digit growth in
- **Feb. 8** XTO Energy picks up more production
- **Jan. 18** XTO Energy begins new year with a bang
- **Jan. 18** Earnings for U.S. majors up 34 percent
- **Jan. 4** Natural gas work continues on Kenai Peninsula
- **Jan. 4** U.S. independents' earnings could drop despite higher prices

GULF OF MEXICO

Noble Energy boosts stake in Swordfish

Exploration and production independent Noble Energy has acquired an additional interest from BP in the Swordfish development project in the deepwater Gulf of Mexico, Noble said May 18.

Noble said it bought all of BP's 50 percent working interest, increasing the company's working interest in the Swordfish project from 10 percent to 60 percent.

Noble said it bought all of BP's 50 percent working interest, increasing the company's working interest in the Swordfish project from 10 percent to 60 percent.

Discovered in 2001, Swordfish is in 4,500 feet of water on Viosca Knoll blocks 917, 961 and 962. Two well penetrations found oil and natural gas pay in multiple, high-quality reservoirs. A semi-submersible drilling rig is scheduled to arrive on location in June to begin development drilling and completion operations, including the drilling of a third well.

Swordfish's development plan calls for the three wells to be connected to existing infrastructure through subsea tieback. Initial production is expected to commence in the first quarter of 2005, ranging from 16,000 to 20,000 barrels of oil equivalent per day.

Charles Davidson, Noble's chief executive officer, said its Swordfish acquisition, combined with the company's recent discovery at Ticonderoga and increased interest in the Lorien field, "will help ensure we see continued strong growth in our robust deepwater program."

Mariner Energy holds a 15 percent working interest in Swordfish and is the operator. Burlington Resources has a 25 percent stake in the project.

—**RAY TYSON,** Petroleum News Houston correspondent

continued from page 7

XTO

tunities in the primary producing fields of Teague, Oletha, Bethel, Haynesville and New Hope.

New positions in Rockies, South Texas

Also, new positions for the company will be established in the Rocky Mountains and South Texas.

In the Rockies, XTO is expanding its coalbed methane presence with the purchase of 67 billion cubic feet of equivalent proved reserves in the Buzzards Bench field of Emery County, Utah. The property is an offset to the Drunkard's Wash field and is currently producing about 12 million cubic feet of equivalent per day. In the South Texas area, the company is purchasing 54 billion cubic feet of equivalent proved reserves in nine counties with net production totaling 20 million cubic feet of equivalent per day.

In the Midcontinent region, XTO said it is adding 67 billion cubic feet of equivalent proved reserves from 11 counties in Oklahoma and the Panhandle of Texas. These properties will contribute about 15 million cubic feet of equivalent production per day.

The remaining 16 billion cubic feet of equivalent proved reserves and net production of 3 million cubic feet of equivalent production per day are contained in various royalties and other miscellaneous properties, XTO said.

Transaction to close Aug. 6

The transaction is scheduled to close by Aug. 6, with an effective date of Jan. 1, XTO said. The company said it expects to finance the deal through a combination of the sale of common stock and bank credit facilities. Additionally, the company said it may consider placement of long-term senior notes.

The company expects to record a significant gain to income upon close of the sale, which is anticipated in the third quarter of this year. The sale is part of plans announced in 2003 to improve the competitive performance of the company's upstream portfolio through the divestment of non-strategic assets and the realignment of strategic business units.

With the sale of its properties to XTO, ChevronTexaco said it has reached agreement to sell about two-thirds of production targeted for sale in the company's ongoing U.S. divestment program.

"This sale is significant," said Peter Robertson, ChevronTexaco's vice chairman. "It is a key step in our drive to streamline our portfolio of assets to approximately 400 core fields … in the United States and Canada. Furthermore, the transaction allows us to focus on maximizing and growing the value of our base business."

Meanwhile, XTO said it has revised its 2004 capital budget for development and exploration expenditures of $600 million to provide for activities on properties acquired year-to-date.

The budget specifically was increased to include $30 million for work in the Barnett Shale, $15 million for activities on the ExxonMobil properties and $15 million for activities on ChevronTexaco properties. Additionally, East Texas and Louisiana will account for $340 million of the total 2004 budget, XTO said, adding that the San Juan, Raton and Arkoma basins combined will get about $100 million in development funds. Alaska, the Permian Basin and the Hugoton Royalty Trust properties' development plans are expected to total another $35 million, while $25 million will be used for exploration, the company said.

The remaining $40 million has been allocated to facilities additions and projected increases in steel prices, XTO said. ●

continued from page 7

DIVE

percent from March's 53.5 and a decrease of 1.7 percent from April of last year. April's Score also was down 1 percent versus the same month last year.

Southeast Asia scored 53.8 in the April survey, down 7.9 percent from March's 58.4 but up 1.8 percent from the year-ago period. The April Score was up 45.9 percent compared to five years earlier.

As for the market performance of drilling rigs in April, jackups scored 52, down 3.8 percent from March but up 20.3 percent for the same period a year earlier, and up 79.3 percent versus five years ago. Semi-submersibles scored 32.3, down 6.8 percent from March and down 1.2 percent from a year earlier, but up 10.2 percent compared to five years ago.

—**RAY TYSON,** Petroleum News Houston correspondent

● CANADA

Energy accounts for 16 percent of all Canadian exports

By GARY PARK

Petroleum News Calgary Correspondent

Natural gas easily outpaced oil, electricity and coal in the export categories, although export volumes dropped to 8.74 billion cubic feet per day from 9 billion in 2002.

Energy exports, almost exclusively to the United States, accounted for 16 percent of Canada's exports in 2003, generating C$62 billion in revenues, up 27 percent from 2002.

The National Energy Board reported that the net gain in energy trade (exports minus imports) for the year was C$36 billion, up C$6 billion from the previous year.

Natural gas easily outpaced oil, electricity and coal in the export categories, although export volumes dropped to 8.74 billion cubic feet per day from 9 billion in 2002.

Despite that 11.5 percent drop in exports, gas revenues surged by 41 percent to C$25.6 billion, reflecting the sharp rise in prices to C$6.75 per gigajoule from C$4.47.

For the first quarter of 2004, Statistics Canada reported that energy exports dropped by 13.7 percent to C$15.48 billion.

Oil exports were up by 88,000 barrels per day to 1.55 million bpd, with the value climbing to C$20.7 billion from C$18.9 billion. Canada imported 887,500 bpd to eastern refineries, representing 47 percent of total feedstock requirements.

The board noted that the energy sector provides 300,000 jobs, or 1.7 percent of the Canadian labor force, but accounts for 6 percent of the gross domestic product.

Oil and equivalent output increased 7 percent in 2003 to 2.48 million bpd, while natural gas liquids added another 577,000 bpd.

Conventional crude fell another 6.2 percent to 572,000 bpd, more than offset by the rise in synthetic crude and bitumen in Western Canada and a 24 percent jump from offshore Newfoundland to 358,500 bpd.

Gas production dropped to 16.8 billion cubic feet per day from 17.3 billion, with new reserve additions replacing about 89 percent of production from 1998 to 2002.

Board chairman Ken Vollman said the drop in conventional oil and flattening out of gas production has forced a shift to more diverse supply sources, such as the Arctic, East Coast and coalbed methane.

As a result Canadians "face increasingly complex and difficult choices in the energy sector as they confront conflicting goals, values and aspirations," he said in the regulator's annual report. ●

LOUISIANA

Whittier takes interest in Cut Off field

Small exploration and production independent Whittier Energy has acquired an operated working interest in the Cut Off field in Lafourche Parish, La., for $1.65 million from an undisclosed private company, the Houston, Texas-based company said May 13.

Whittier said it acquired an average working interest of 73 percent in four producing oil wells, one salt water disposal well and two shut-in wells. Gross production from the field is about 210 barrels of oil and 150,000 cubic feet of gas per day. Net production to Whittier is about 105 barrels of oil and 35,000 cubic feet per day.

Whittier said it paid for the property using $650,000 from working capital and $1 million from its revolving line of credit with Compass Bank. The company has estimated net proved reserves in the field to be in excess of 350,000 barrels of oil equivalent.

"This property is a timely purchase given the current high commodity price environment we are in." said Bryce Rhodes, Whittier's chief executive officer.

Whittier operates properties in Texas and Louisiana and owns various non-operated working interests in Oklahoma, Texas, Wyoming and California.

—**RAY TYSON,** Petroleum News Houston correspondent

CALGARY, ALBERTA

E&P firm moves assets into trust

Formed in 1988, Canadian E&P junior Zargon Oil & Gas has joined the trust sector to take advantage of a "more tax-efficient structure," while continuing to explore for natural gas and exploit existing oil reservoirs.

The Calgary-based company announced May 17 that, rather than following the recent trend of creating a production-focused trust and small exploration-focused junior, it will move all of its assets into Zargon Energy Trust.

The trust, assuming approval by two-thirds of Zargon shareholders in July, will produce 30 million cubic feet per day of gas and 3,400 barrels of light and medium oil.

Based on a reserves report by McDaniel & Associates Consultants, the trust will have proved reserves of 18.86 million barrels of oil equivalent and 24.9 million boe of proved plus probable reserves. The reserve life index will be 5.9 years for proved producing reserves, 6.5 years for proved reserves and 8.7 years for proved plus probable.Zargon plans to reinvest half of its cash flow to maintain production levels and distribute the other half to unit holders. Based on first-quarter results, that would have seen the distribution at 14 cents per trust unit per month.

Management said it plans to maintain Zargon's 2004 capital budget at C$34 million.

—**GARY PARK,** Petroleum News Calgary correspondent

● CANADA

Canadian execs cautious on capex increases

By GARY PARK

Petroleum News Calgary Correspondent

Canadian oil and gas executives lagged well behind their counterparts in the United States and outside North America when asked in a KPMG survey whether their planned 2004 upstream spending might increase by more than 10 percent.

In a news release, KPMG said only 4 percent responded positively in Canada, compared with 20 percent in the United States and 35 percent worldwide.

Of the 126 executives surveyed, 80 percent of respondents in Canada said their spending would be the same or increase this year, compared with 79 percent in the United States and 91 percent outside North America.

KPMG said the announced or imminent sales of Canadian reserves by Chevron Canada Resources and Murphy Oil support the overall conclusions that there are better opportunities elsewhere in the world.

Of the U.S. respondents, 35 percent said they would hike their budgeted spending if U.S. federal acreage now off limits to exploration were to become available for leasing and permitting.

In addition, 56 percent were confident that a major U.S. domestic energy policy would be achieved within two to five years, although 31 percent think a policy is unlikely to happen. On the merger and acquisition front, 54 percent expect to see consolidation among small independents and 52 percent are counting on super and large independents acquiring smaller peers.

Current natural gas prices are having a "significantly negative effect" on industrial production, in the view of 24 percent of respondents, while 60 percent say high prices are having a "modestly negative" impact on consumer spending and 59 percent believe the prices are having a "modestly negative" effect on inflation. ●

● SAN ANTONIO, TEXAS

Texas firm accelerates 2004 drilling program

Large inventory, good prospects cause The Exploration Co. to expand program by 50%; using proceeds from $16M private placement

By RAY TYSON
Petroleum News Houston Correspondent

The Exploration Co., a small but growing San Antonio, Texas-based independent with a strong acreage position in the prolific Maverick Basin of southwest Texas, is planning a hefty 50 percent plus increase in capital spending this year in order to accelerate development drilling on its 492,000-acre Maverick lease block.

To pay for the work, the company said it entered into purchase agreements with investors for the private placement of 4,266,669 shares of its common stock at a purchase price of $3.75 per share for gross proceeds of $16 million.

"Our limiting factor has been capital, not prospects," James Sigmon, the company's chief executive officer, said May 18.

The Exploration Co.'s "multi-play/multi-pay" strategy has led to the identity of "numerous attractive targets," Sigmon said, adding that new financing will help the company accelerate development of one of its most promising plays, the gas-prone Glen Rose reefs.

"These reefs have been a consistent producer for years in the Maverick Basin," he said.

He said analysis of 3-D seismic from a portion of the so-called Burr/Wipff prospect turned up as many as 15 reefs and that the company plans to commence drilling there immediately.

Company's reserves could double

If only half of the reefs are eventually brought into production, the company's technical staff estimates "we can expose the company to approximately 28 billion cubic feet of new gas reserves by year end," Sigmon said.

The Exploration Co. reported year-end 2003 proved oil and gas reserves of 28.4 billion cubic feet of gas equivalent, a 21 percent increase from year-end 2002 reserves of 23.5 billion cubic feet of equivalent. Production in 2003 totaled 4.83 billion cubic feet of equivalent, up 11 from the previous year's 4.37 billion cubic feet of equivalent.

The Exploration Co. said it expects to receive proceeds from the stock sale of $15.04 million, net of expenses, allowing the company to expand the drilling portion of its 2004 capital expenditure program by more than 50 percent.

The Exploration Co. plans to use $8 million of the proceeds to drill wells targeting Glen Rose reefs on the 80,000-acre Burr/Wipff prospect, which the company owns 100 percent. The company said the remaining $7 million would be used to increase drilling activity on its Comanche prospect, restore liquidity to its balance sheet and complement other operations, development and general corporate activities.

"Recent headlines in the exploration and production industry have reflected high valuations on firms with large, undeveloped acreage positions in proven oil and gas provinces," Sigmon said.

"Accelerating our drilling and development activities will enable (the company) to leverage its growing prospect inventory, better reflecting the full potential of its Maverick Basin acreage." Included in the stock deal are warrants for an additional 1,280,000 common shares exercisable at $4.25 per share.

Stock purchasers were private, U.S.-based investment funds, led by Crestview Capital Master LLC of Northbrook, Ill., The Exploration Co. said. First Albany Capital and C.K. Cooper & Co. served as placement agents for the transaction.

In the first quarter of 2004, The Exploration Co. generated $11.4 million in total revenues, up 25 percent from $9.1 million recorded in the first quarter of 2003. ●

GULF OF MEXICO

First production launched from Gulf's Llano field

Oil and gas production has begun from the Llano field in the deepwater Gulf of Mexico, operator Shell Exploration & Production Co. said May 17.

Llano, on Garden Banks blocks 385 and 386, is about 200 miles southwest of New Orleans in about 2,600 feet of water. The field is currently producing about 10,500 barrels of oil and 26 million cubic feet of gas per day from one well tied back 11.5 miles to Shell's Auger tension-leg platform.

Dedicated production capacity at Auger is 25,000 barrels of oil and 75 million cubic feet of gas per day. A second well is planned to be on production later this month, Shell said.

Llano is Shell's second project to use 15,000 pounds per square inch subsea equipment. Total development costs were about $215 million, including modifications to the Auger tension-leg platform. The project was completed on time and within the allocated budget, Shell said.

"This is the fifth subsea system that we have tied back to Auger," said Gaurdie Banister, technical director for Shell EP Americas. "This tieback allows the Llano owners to efficiently leverage Shell's existing infrastructure for their mutual benefit."

Shell holds a 27.5 percent interest in the field. Amerada Hess owns 50 percent and ExxonMobil has the remaining 22.5 percent.

—**RAY TYSON,** Petroleum News Houston correspondent

NORTH AMERICA

Rig count up by 9, despite a loss of 18 rigs in Canada

The total number of rotary drilling rigs operating in North America, compared to the previous week, increased by a net nine rigs to 1,329 for the week ending May 14, according to rig monitor Baker Hughes. The rig count also was up by 190 vs. the same period last year.

However, the rig count in Canada alone fell by 18 to 167 during the recent week compared to the prior week, but was still up by 68 compared to the year-ago period.

The United States helped offset the drop in the Canadian rig count, increasing by a net nine to 1,162 rigs from the previous week and increasing by a net 122 rigs vs. the same weekly period last year. Land rigs alone increased by 11 to 1,043 compared to the prior week, while the offshore rig count slipped by three to 95. The number of inland water rigs increased by one to 24.

Of the total number of drilling rigs operating in the United States, 1,004 were drilling for natural gas and 157 for oil in the recent week, while one rig was being used for miscellaneous purposes. Of the total, 765 rigs were drilling vertical wells, 282 directional wells and 115 horizontal wells.

Among the leading producing states in the United States,

see **COUNT** *page 12*

● COOK INLET, ALASKA

Putting together the puzzle

Aurora has developed known gas reserves on west side of Cook Inlet, shot 3-D programs, larger 2-D program, plans to stay onshore

By KRISTEN NELSON

Petroleum News Editor-in-Chief

Aurora Power, Aurora Gas and Aurora Well Service are a family of companies — all working natural gas in Southcentral Alaska's Cook Inlet basin.

The original company, Aurora Power, was formed 10 years ago to market natural gas to large customers and it currently sells some 7 billion cubic feet a year, serving some 1,200 meters, said the company's president, Scott Pfoff. Almost 5 bcf went to large commercial customers, Pfoff told the Alaska Support Industry Alliance May 13, and the rest went to industrial users.

And, Pfoff said, Aurora has just signed a two-year agreement with the U.S. Department of Defense to provide natural gas to Elmendorf Air Force Base and Fort Richardson, the Anchorage, Alaska-area military bases, and will also be providing natural gas to a number of federal buildings. This is the company's second Department of Defense contract, he said.

Goal has been production

The company's goal from the beginning was to be a producer of gas, as well as a marketer, and in 2000 Aurora Gas was formed.

Aurora Gas is a niche player, Pfoff said, with its focus on Cook Inlet natural gas, "and we're looking for gas that

see **PUZZLE** *page 12*

JUDY PATRICK

This year's seismic is a "very aggressive program to try to identify several very promising prospects in a large area." The company did 2-D, rather than 3-D, because "this is a very large aerial extent" with several prospects targeted. —Scott Pfoff, president, Aurora

● NORTHERN ALBERTA

Pondering a partnership

Canadian independent wants to own as much of oil sands megaproject as possible; ready to delay completion dates to keep costs under control

By GARY PARK

Petroleum News Calgary Correspondent

Canadian Natural Resources remains undecided over whether to take on partners for its C$8.4 billion Horizon oil sands project in northern Alberta.

The Canadian independent has "talked to a number of people, but we're still evaluating whether we need a partner or not," Chief Operating Officer Steve Laut said after the company's annual meeting May 6.

He said CNQ, as Canadian Natural is widely known, has the ability to tackle the mining and upgrading project alone, despite its inexperience in the oil sands field.

"We'd like to keep as much of it as possible," Laut said.

First phase production in 2008

The Alberta Energy and Utilities Board approved an application that calls for a C$5 billion first phase to produce 110,000 barrels per day of upgraded bitumen starting in 2008, followed by a C$2.3 billion expansion to add 155,000 bpd in 2012 and a final stage costing about C$1.1 billion.

Horizon will tap an estimated 18 billion barrels of bitumen in 250 square miles of leases, with about 6 billion barrels recoverable using current technology. The operating life is estimated at 42 years.

CNQ believes it needs a sustained West Texas Intermediate crude price of US$16 per barrel to generate an 8 percent after-tax return, which would rise to 15 percent with oil prices at US$23.

Laut said Horizon will be a "mega-project different from any other mega-project that's been done in Alberta before."

Cost control ahead of deadlines

Against a background of oil sands projects that

see **PARTNERSHIP** *page 12*

continued from page 11
PUZZLE

really has already been discovered, one way or another."

When companies were exploring Cook Inlet for oil in the 1960s, they found a lot of gas, "sometimes they knew it and they tested it, sometimes they didn't, they just blew right through it with heavy mud that invaded the zones," he said. After all, they weren't looking for gas.

Aurora focuses on what is known, Pfoff said: "Our whole niche is to use those logs and the geology and the well control and then some of the seismic that's been shot since, and put together a puzzle to go back in and find low-risk opportunities to develop natural gas."

Aurora found an industry equity partner, Tulsa, Okla.-based Kaiser Francis Oil Co., and since 2000 has invested more than $30 million in Cook Inlet.

Why was Kaiser Francis interested?

"They know this is a resource-rich basin that has not been fully developed and there's a lot of technical opportunities to go out there and find additional hydrocarbons in the inlet," Pfoff said.

West side focus

About 100,000 of Aurora's 130,000 acre position is on the west side of Cook Inlet, Pfoff said, the majority, some 76,500 acres, in the Moquawkie area; 17,200 acres at Nicolai Creek and 7,400 acres at Long Lake. He said the company also has several "very promising prospect positions on the east side of the Cook Inlet as well."

In the winter of 2002-03, Aurora shot 25-26 square miles of 3-D seismic on the west side, nine square miles at Nicolai Creek and almost 16 square miles at Moquawkie.

Aurora is the smallest of the six Cook Inlet producing companies, Pfoff said, and started production at Nicolai Creek, the company's first acquisition after Aurora Gas was formed. The company reentered and recompleted three of the existing wells at Nicolai Creek, and drilled one new well. All are on production, he said, with a combined production of some 5 million cubic feet per day.

In the winter of 2002-03, Aurora shot 25-26 square miles of 3-D seismic on the west side, nine square miles at Nicolai Creek and almost 16 square miles at Moquawkie.

The acquisition of the Lone Creek gas field and the Moquawkie area property included one well head and some 50,000 acres around the well "that have additional opportunities," Pfoff said. Infrastructure and a pipeline were put in, and the Lone Creek well is producing some 5 million cubic feet a day, although he said that production is "a little more demand driven" than at Nicolai Creek.

Aurora then reentered the Mobil Moquawkie No. 1 well, which tested at 7-8 million cubic feet a day.

Most recently, he said, Aurora formed the Three Mile Creek unit with partner Forest Oil. Work requirements for the exploration unit include seismic, which the company has already shot, and an exploration well next year. But, Pfoff said, they are looking at that seismic, and "if we like what we see, we're hoping we might even get that well drilled this year."

Moquawkie gathering system being completed

Aurora is "laying pipeline right now" at the Mobil Moquawkie reentry, and just wrapping up the 2004 seismic program. This year's seismic, Pfoff said, is a "very aggressive program to try to identify several very promising prospects in a large area." The company did 2-D, rather than 3-D, because "this is a very large aerial extent" with several prospects targeted, he said.

The company is also gearing up for its 2004 well work program, which includes one recompletion at Nicolai Creek where the company is going to "open up some additional zones and prove up some additional reserves."

One new well will be drilled "at yet another field that was discovered looking for oil," the Albert Kaloa gas field. Pfoff said there are two wells at that field, but they are not salvageable because of the way they were plugged and abandoned, "so we're going to drill a new one, it's a fairly shallow zone anyway, so we can do it with our equipment."

The company will also drill what Pfoff called "a very exciting exploratory reentry."

Moving right along

And what are the company's plans for the future?

"We're going to keep our butts on shore," Pfoff said, commenting that he frequently gets calls from people wanting to sell Aurora opportunities offshore in Cook Inlet, some of which even come with platforms.

But, he said, Aurora plans to stay onshore, close to infrastructure: "We're going to look for those shallow pockets of gas and we're not going to be big risk takers. And that's our business model."

On the other hand, as the company works through its inventory of reentry candidates it will do "more exploratory type drilling."

The Three Mile Creek unit is an example, he said. There are wells in the area, and the company is shooting seismic, "but it's going to be much closer to what I would call a wildcat well than a simple developmental reentry…"

A rig to fit drilling needs

The big fields discovered in the 1960s are in decline, he said, and there is an opportunity for more gas development. "We see prices that are going to finally give us as producers the incentive that we need to go out there and make these kinds of investments."

Part of that investment is Aurora Well Service, the Aurora company which brought a workover rig to Cook Inlet from Wyoming.

"These fields are not huge and we can't afford to put full-blown drilling rigs on a 10 or 20 bcf reservoir and make it work," Pfoff said.

Aurora Well Service's rig was designed for reentry work, "it's smaller, more portable … It's a carrier-mounted unit and therefore less expensive."

Aurora modified the rig to drill shallow wells, top to bottom, and while the rig has so far worked only for Aurora Gas, at some point it will be available to others.

Pipelines will become an issue

Pfoff said pipelines are "going to become an issue in Cook Inlet as more and more of these smaller fields" are developed and need to move production to market because some of the pipelines in Cook Inlet are privately owned. Those pipelines are "not common carriers, they're not open access" and "being a common carrier is not a business that they want to be in."

But if you look at a map of the pipelines in Cook Inlet, Pfoff said, "you just have to conclude that some of these lines are going to have to open up … to other companies that need to get gas from the west side of Cook Inlet over to the east side."

It's an issue Aurora is working on, he said. "We're working through it, it's not warfare or anything, it's just a transition…"

Infrastructure is also an issue on the west side. There are roads, but they don't connect to the state's road system. "It seems like every project that we undertake, we're having to deal with infrastructure. … Even though we're targeting gas reserves and the development of gas reserves, in the process we end up upgrading the infrastructure system over them. In addition to doing well work, we've put in bridges, we've put in roads, we've put in power cables. I mean we've had to do all that as part of developing this remote area."

Royalty valuation a problem

Pfoff said there is also a taxation issue for Cook Inlet natural gas producers, and that is the value of royalty gas.

"Royalty owners deserve a fair value for the product — for the gas or the oil — whatever is produced pursuant to the lease," he said. "And I don't begrudge them that. We want to pay a fair royalty value."

But, he said, when he does the best he can to market his gas, and then the state or other royalty owner says the royalty has to be paid on a higher value than the price Pfoff got for the gas, "whose pocket does that come out of?"

"We're starting to see tremendous diversity — variations in some of the gas contracts," he said. Different contracts pay different prices for the gas, he said, "yet the royalty valuation methodology will oftentimes require you to pay on a weighted average of utility contract prices, even though the best deal you can get might be something lower than that."

Pfoff said he thinks the state is willing to listen to discussions about this problem, and he thinks it can be worked out.

That still leaves another problem which makes Cook Inlet a high-cost environment, the lack of momentum: there aren't enough companies exploring for natural gas in the basin.

"With the amount of activity that we have, it's kind of on-demand: sometimes equipment has to be brought in from the Lower 48 or the North Slope, and it's going to cost you more."

Then, he said, there is the regulatory and permitting issue.

"We just need to figure out a better way." Even though each permit may be for a good reason, "there needs to be one-stop shopping somewhere, some way to get through this process quicker than what it takes right now." ●

continued from page 11
COUNT

Wyoming's rig count rose by seven to 67 during the recent week, according to Baker Hughes. Texas gained two rigs for a total of 503 rigs. Louisiana's rig count was down by three to 165 rigs, while Oklahoma's slipped by one to 157 rigs. New Mexico's rig count was unchanged at 64, as well as California at 26 and Alaska at seven.

—**RAY TYSON,** Petroleum News Houston correspondent

continued from page 11
PARTNERSHIP

have piled up cost overruns in the billions of dollars, he said CNQ will put cost control ahead of completion deadlines.

By taking a different approach on engineering, design and labor, Horizon will be "different from the fast track" strategies that have created problems for oil sands developers, he said.

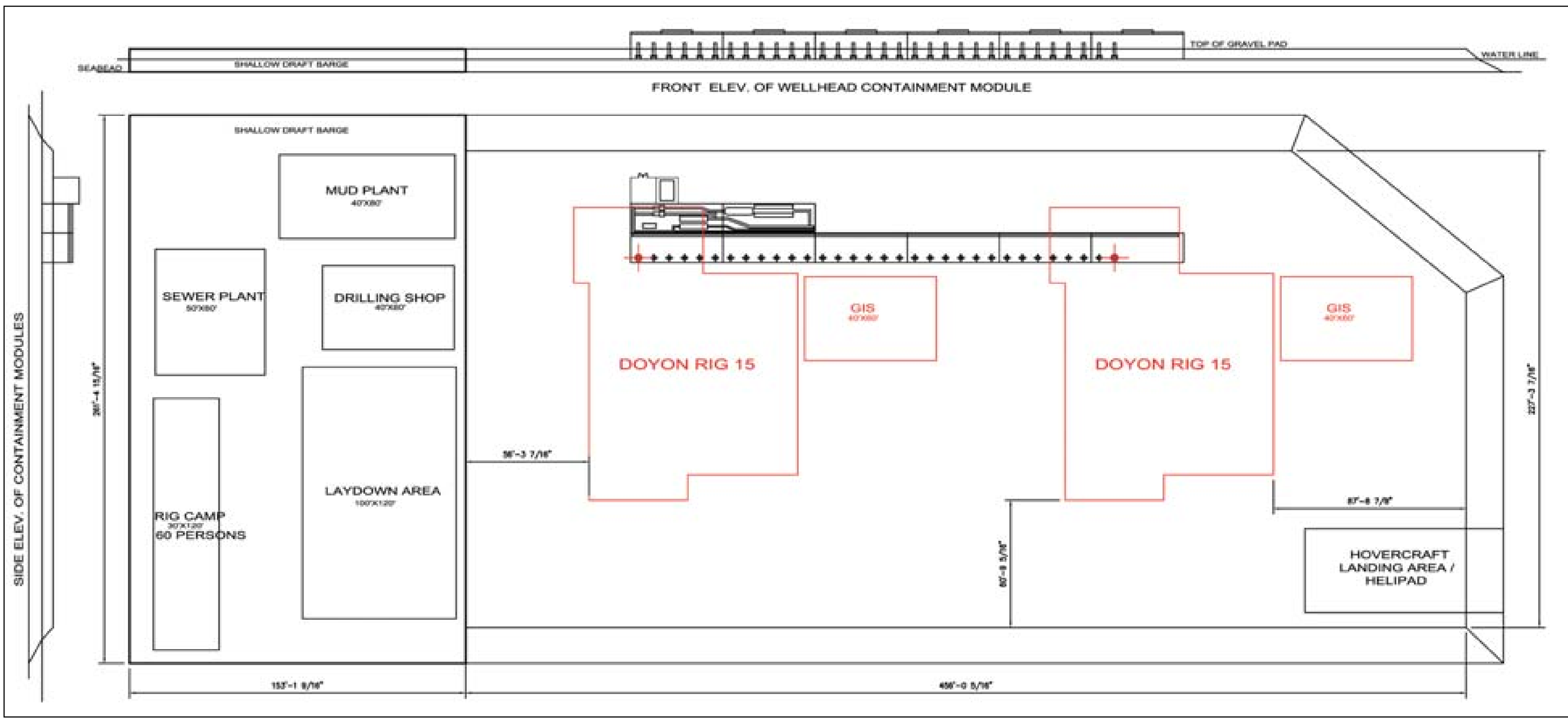
Over the short term, Laut said CNQ will take a proactive approach to heavy oil marketing by increasing its capacity for blending synthetic and heavy crudes, including its "synbit" product that is attracting interest in the U.S. Padd II refining markets as an alternative to medium sour crudes from Africa and the Middle East.

He said CNQ is interested in construction of a conversion facility in Alberta to blend up to 250,000 bpd and, by this fall, hopes to expand its own blending capacity to 140,000 bpd.

Laut said that over the medium term the removal of equivalent volumes of heavy oil from markets in the form of crude oil blends should lower price differentials and enhance the economics of heavy and synthetic oil.

Meanwhile, CNQ has pushed its plans for a steam assisted gravity drainage project adjacent to the Horizon lease beyond 2012.

Real Doucet, vice president for oil sands, said last month that the company aims to utilize the initial infrastructure that the Horizon mining operation has created for the steam assisted gravity drainage venture, which is expected to produce up to 70,000 bpd. ●



COURTESY ARMSTRONG OIL & GAS

Outline of offshore facility. Barge at left end of SPIT production modules is only in place during drilling.

continued from page 1

CRACKING

Adam, who works for Calgary-based Tri-Ocean Natchiq Engineering, the engineering and technology unit of Anchorage-based ASRC Energy Services, has spent most of his 15-year career designing and supporting drilling facilities around the world, including Europe (North Sea) Russia, Canada and Alaska.

"This (production system) is a game changer …. It changes the whole equation on the North Slope. … We call it cracking the nut, in the same way they cracked the nut at Ekofisk, the first field to be developed in the North Sea, 30-some years ago," he said.

SPIT: Stu's production in a tank

"What got us started on this," Gustafson said, "was you have to be able to assure people that oil can be safely developed both onshore and offshore with a zero tolerance for environmental incidents."

He asked himself, what if you just contained the entire drill site? What if you built your development drill site inside tanks? Tanks which would not only prevent a drop of oil from reaching the environment but would contain a larger spill. With pumps so that, in the event of spilled oil, you'd pump it right into the line carrying oil to processing facilities.

When you're developing resources offshore, you would bring your drill rig and temporary camp — everything you need to drill your production wells — out to the drill site on a shallow-draft barge, slide back the tank lids, drill your wells and tow the barge away and after their productive life, you plug and abandon the wells and remove the tanks.

Gustafson started with hand-drawn sketches, taking his ideas to regulatory agencies for input and direction, including the U.S. Corps of Engineers, the North ZSlope Borough, the Alaska Department of Natural Resources and the Alaska Department of Environmental Conservation.

He has been showing illustrations of the proposed drill site design to regulators and other North Slope operators for about two and a half months, he told Petroleum News in a mid-May interview.

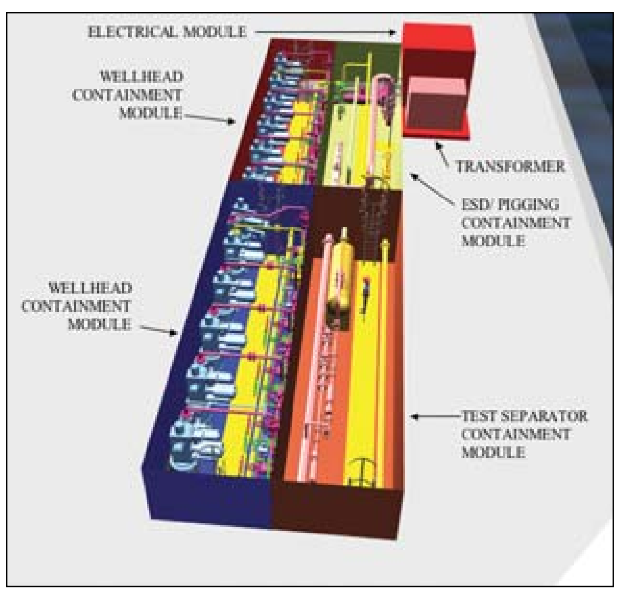
KISS, the well-known acronym for "keep it simple stupid," was suggested as a name when Gustafson and Armstrong prepared to apply for a patent, but Linda Gustafson, Stu's wife, had a better idea. It's as simple as spitting, she said, so the working name is SPIT, "Stu's production in a tank."

Smoother, faster, better — and cheaper

Initially, Gustafson wasn't focusing on saving money.

"When you find a way to do something smoother, faster and better, it becomes cheaper," he said. "In this case, it is an order of magnitude cheaper, not just an incremental, small percentage change."

But the savings doesn't affect drilling, which is usually two-thirds of a development project's costs: "We're not cutting the cost of the program in half, we're not cutting the cost of pipelines in half — we're cutting the cost of the drill site in half," Gustafson pointed out.



COURTESY ARMSTRONG OIL & GAS

One state official, who preferred not to be identified, said the current North Slope "paradigm" for a near-shore drill site would be "about $29 million. The numbers we've been shown suggest Stu's system will drop that cost to about $12 million. These are rough numbers, but they're not rocket science. His design is the definition of simple. It's amazing no one has put this together before."

Truckable modules

Another challenge that contributed to the design of SPIT "was that offshore, we didn't want to have any emissions; we didn't even want to have any fuel," Gustafson said.

His new system: "Power for the drill site comes from onshore, with just a back-up generator at the drill site for emergencies."

He was also looking at the issue of how to provide DEC with "the three C's: command, control and containment."

SPIT has "control from an onshore operator — the tanks are remotely monitored from shore, as in the Gulf of Mexico, and the operator can shut in a wellhead from shore. He doesn't have to go to the tank in the middle of a North Slope blizzard."

So that's command and control. "That left containment," he said. "How do we get immediate response for containment?" Gustafson had initially suggested a barge, but was told it would cost too much. That's when he started to think of putting the wells in a module, with a lid to control any plume or spray.

Modular truckable system

The result was a modular system (see illustration): A series of tanks, 51 feet long, 14 feet wide and 14 feet deep, a size that could be trucked to the North Slope.

"Piping will be installed in the tanks before they go north. The lids slide open," Gustafson said.

Installation? "Five-foot deep holes are dug in the gravel and the tanks are lifted into place."

What anchors the tanks? "The first thing pipe you put in for a well is conductor pipe, which normally goes to about 200 feet," he said. "You drive the surface conductor and then fasten it to the floor of the tank. That 200 feet of pipe is the pylon holding the tank in place. They're our foundation — a stronger foundation than you would ever design.

"You bolt additional tanks on, and flange the piping together from tank to tank with the same flexible high-pressure fittings used on platforms in the Gulf of Mexico," Gustafson said.

"The drilling rig cantilevers for drilling, and temporary I-beams will be put in place during drilling so the tank walls won't have to be built extra heavy for the drilling phase of the operation."

The tanks and lids would be insulated and because the oil would be produced at about 110 degrees, "we do not have to heat trace any lines or insulate the pipelines at the drill site, because they are all inside the tanks," he said.

There would be heaters, but only for emergency back-up.

And because the drilling portion of the operation — drill rig, camp, sewer plant, mud plant and all the pipe — would be on a barge that would leave at the end of drilling, the footprint size would drop "from six acres to three acres," Gustafson said.

What happens if there is a leak?

What happens if there is a leak?

Command, control and containment, he said.

"Say well No. 11 develops a leak. We already have command: the operator is sitting onshore, he has visual and heat-sensing cameras so he has a picture — he doesn't care if it's a blizzard outside, he can see it. He doesn't have to get to it. And he shuts it off.

"This is the same technology in terms of command and control" that is used in the offshore platforms in the Gulf of Mexico and the North Sea, Gustafson said.

"And it's leaking? Where's the oil going? Down in the tank; and what happens to oil in the bottom of the tank?

"We have drain lines in these tanks, sump lines, and we have a motor over here and it sucks like a bilge pump in a boat, except instead of pumping it overboard, we're going to put it right back in the pipeline," Gustafson said.

There is a tank blowout requirement for major spills, but with "three tanks in a row, we already have that tankage on tap, on site — we have that capacity." Should a spill fill one tank, there are openings at the top of the sidewalls between the tanks, and the oil would flow into the next tank.

And the whole design uses existing technologies, he said. "It's just combining existing technologies into a single system."

Without spilling a drop

Armstrong is involved in "multiple projects" on the North Slope, Gustafson said. "We are trying to capitalize on additional cost savings in terms of repeatability for multiple projects."

SPIT, he said, works for different gravities of oil, different depths of wells.

"It's just meant to take a three-phase flow, test it or evaluate and meet the regs and get it to a processing facility," he said.

"Without spilling a drop." ●

CANADA

Natural gas dominates drilling agenda

For the first four months of 2004, regulators in Alberta, Saskatchewan and British Columbia issued 8,078 permits for new wells, 72 percent of them targeting gas.

Oil prices at 14-year highs have not been enough to divert Western Canada's conventional producers from their hunger for natural gas.

For the first four months of 2004, regulators in Alberta, Saskatchewan and British Columbia issued 8,078 permits for new wells, 72 percent of them targeting gas.

Across Canada, the tally to the end of April was 8,889, up 5 percent from the same period last year, but April's count of 1,478 permits was down 9 percent from April 2003.

Coalbed methane continued its steady advance in Alberta, which approved 284 wells compared with 66 a year earlier.

Leading operators were EnCana with 407 licenses, Husky Energy 124, Apache Canada 88, EOG Resources Canada 76 and Petro-Canada 67.

—GARY PARK, Petroleum News Calgary correspondent

ALBERTA

Alberta producers rewarded for use of carbon dioxide in enhanced oil recovery

Four companies using carbon dioxide in enhanced oil recovery projects will share a C$14 million bonus from the Alberta government.

Projects planned by Anadarko Canada, Apache Canada, Devon Canada and Penn West Petroleum all qualify for the royalty credits under the province's plan to reduce greenhouse gas emissions by encouraging the sequestration of CO_2 as part of oil and gas production.

The CO_2 is pumped into aging reservoirs to restore pressures and allow the final barrels to be extracted. Apache believes it has the potential to produce 616,420 barrels from its project.

Energy Minister Murray Smith said the government is eager to promote innovation and technology "that will enhance the sustainable development of the province's abundant energy resources."

Devon, in partnership with three other producers, plans to inject about 110 metric tons of CO_2 per day for the duration of a project in Swan Hills, central Alberta.

Apache is working in the Zama Keg River oil pool project in the northwest, Anadarko has an oil pool project in the south and Penn West is operating the Pembina Cardium project in central Alberta.

The Alberta government said in a news release that CO_2 projects face high initial costs because of the cost of capturing CO_2 from sources such as oil refineries, oil sands upgraders or power plants and from the lack of pipelines to move the gas to the field for injection.

However, the government said there is a "significant opportunity" to link the supply of CO_2 with the sources for demand, with oil sands upgraders rated as a potentially large and reliable source of pure CO_2.

The province anticipates its new programs will generate about C$30 million in incremental royalties over 20 years, while providing up to C$15 million in royalty deductions over five years, with credits peaking at 30 percent of approved project costs.

—GARY PARK, Petroleum News Calgary correspondent

GULF OF MEXICO

MMS sets up electronic forms for wells

The Minerals Management Service has set up a new system to allow oil companies active in the Gulf of Mexico to submit several forms electronically to speed approvals, starting in June.

As part of a government reengineering effort, MMS will allow the electronic filing of permits to drill or modify wells, well activity reports, end of operation reports, and rig movement notifications.

Johnnie Burton, director of the agency, said a study indicates the new eWell permitting and reporting system will cut processing time by 50 percent, reducing expensive rig waiting time. MMS handles about 20,000 such applications annually.

"Industry has been a willing partner to help improve the design of the system," said Chris Oynes, regional MMS director for the Gulf of Mexico. "Operators volunteered to test the system over many months, and through their input, many facets of the application were modified to enhance the ease of operation."

The system will ensure security of proprietary data while providing real-time public access to data that are part of the public record, according to Oynes.

Lessees will receive an application manual this month with directions on gaining access to the system, while training sessions are planned this summer. More than 50 companies have already signed up for the training, according to MMS.

The new system goes into effect on June 1, and the agency expects 100 percent participation within a year.

—ALLEN BAKER, Petroleum News contributing writer

PENNSYLVANIA

Gas prices drive Pennsylvania drilling

High natural gas prices are driving a record-breaking demand for well-drilling permits in northwestern Pennsylvania. Gas prices, and the demand for permits, have been increasing steadily for about the past five years.

In March 2003, the Pennsylvania Department of Environmental Protection issued 233 drilling permits for the 12-county northwestern Pennsylvania area — a monthly record that stood until 240 permits were issued in March. In the first four months of this year, 580 permits have been issued. Last year 609 permits were issued in the first four months.By comparison, 225 permits were issued in the first four months of 1999.

"I don't think we can be any busier. There's not the equipment out there to drill any faster," said Paul Kucsma, the department's northwest regional manager of oil and gas monitoring and compliance. "There just are not any more rigs available."

Industry officials are stopping short of calling the situation a boom, however, saying that higher steel prices have driven up the cost of drilling — keeping profits from climbing as high as some drillers might like.

"The increased demand for natural gas is reflected in the increased price we've seen over the past couple of years, and that's reflected in the drilling activity," said Steve Rhoads, executive director of the Pennsylvania Oil and Gas Association. "There's good cash flow for the producers, but I wouldn't call it a boom."

Gas formations in northwestern Pennsylvania are generally reached by drilling 2,500 to 6,000 feet deep. The rule of thumb is a commercial well would cost $40 per foot to drill and about $160,000 on average to complete. But those numbers are in flux because of rising steel prices.

—THE ASSOCIATED PRESS

● ALBERTA

Carrot-and-stick approach to EOR

By GARY PARK

Petroleum News Calgary correspondent

The use of fresh water in enhanced oil recovery projects should be reduced, but not banned, said an advisory committee report to Alberta Environment Minister Lorne Taylor.

It said an immediate end to the practice would not be a "reasonable response" until a voluntary approach has been tested.

However, if sufficient reductions aren't achieved through voluntary efforts, the government should impose a "mandatory regulatory requirement," the 23-page report said.

The committee noted that EOR accounts for more than half of Alberta's output of conventional light oil and generated C$447 million in royalties in 2001.

Over the past 30 years the use of water for conventional waterflood projects has been shrinking in Alberta due to improved water recycling methods and a decline in the remaining recoverable oil resources in existing conventional EOR projects.

But water use in thermal recovery projects has grown, despite some technological advances in the use of saline groundwater.

Government statistics show that water diverted for EOR use dropped to 47.5 million cubic meters in 2001 from 88.7 million in 1972. The 2001 tally included 37 million cubic meters of "make-up" water, of which 78.1 percent was non-saline.

Environmentalists, farmers and ranchers oppose the use of underground and surface fresh water because it permanently removes that water from the hydrological cycle, especially in recent years as Alberta has been crippled with a series of droughts. Studies show that in the late 1990s rivers in Alberta and Saskatchewan were flowing at 60 percent to 19 percent of their historic levels.

The Athabasca River in northeastern Alberta, the single most important source of water for the oil sands, is declining fast, said University of Alberta ecology professor David Schindler.

He said there are projections that by the mid-2000s the base will be only 80 to 90 cubic meters per second. The current flow is calculated at about 675 cubic meters.

"We'll see who's right, but I don't think it's right to play Russian Roulette with the system," he said.

Taylor, while suggesting that wars will be fought over water "as we move forward," noted that the oil and gas sector accounts for only 4.6 percent of the water licensed for use, yet the industry contributed C$7.2 billion in royalties to government coffers last year. ●

ALBERTA

Alberta regulators approve plans for start-up oil sands venture

Privately held Deer Creek Energy has taken the next step on a long road towards an oil sands project that could ultimately see the start-up company join the oil sands big league.

The Alberta Energy and Utilities Board gave its approval to the expansion of the Joslyn project to 12,000 barrels per day, following which the Deer Creek board agreed on May 14 to proceed with commercial development of the second phase of a steam-assisted gravity drainage project.

Deer Creek President and Chief Executive Officer Glen Schmidt said the regulatory green light is a "significant milestone."

The company started Phase I steam-assisted gravity drainage operations on April 1, aiming to reach a peak 600 bpd by mid-2005.

Meanwhile, Deer Creek has completed 560 wells and more than 650 miles of geophysical information.

Engineering work is well advanced for Phase II and more equipment orders are expected to be placed this fall, followed by facility construction and field operations in the final quarter. Full production is targeted for mid to late 2006.

Deer Creek's long-range plans have included two steam-assisted gravity drainage projects of 30,000 bpd each and one mining project of 100,000 bpd, exploiting a lease with in place reserves of 7.5 billion barrels.

—GARY PARK, Petroleum News Calgary correspondent

BRITISH COLUMBIA

Premier challenges federal minister

Premier Gordon Campbell is locking horns with a fellow British Columbian over the state of scientific knowledge of the offshore oil and gas industry.

Federal Environment Minister David Anderson, who represents a British Columbia constituency in the House of Commons, said the moratorium on exploration off the British Columbia coast will remain in place until the knowledge gaps are filled.

Campbell, who has set 2010 as the start-up date for commercial operations, insisted there are no gaps in the science.

"If they can (produce oil and gas) in the North Sea, if they can do it in the Gulf of Mexico, if they can do it in an iceberg highway in Newfoundland, surely we can do it in British Columbia," he said May 17.

He said two expert panels have reviewed the offshore without raising any insurmountable obstacles.

Campbell said his government would never consider opening up the offshore if it was not convinced that "sound science and new technologies" would allow an industry to operate safely.

—GARY PARK, Petroleum News Calgary correspondent

natural gas

ALBERTA

MGV notches success with coalbed tests in Alberta

Coalbed methane producer MGV Energy is notching success in its southern Alberta plays, logging output of 200,000 cubic feet per day from test wells.

Glenn Darden, president of Texas-based Quicksilver Resources, the parent company of MGV, said the wells north of the Palliser block are averaging double the volumes from MGV's commercial wells northeast of Calgary.

He told a conference call May 10 that the coals are "very consistent over quite a large area and we're not seeing any water."

Five projects outside Palliser going online this year

Darden said five different development projects outside the Palliser block will be brought on this year, with the major focus on the Horseshoe Canyon area, which can come on stream without dewatering delays.

With 180 coalbed methane wells now in production, MGV quadrupled output in the first quarter to 18.6 million cubic feet per day from a year ago and received an average US$4.52 per thousand cubic feet for its gas.

The company is targeting 21 million cubic feet per day in the current quarter and expects to end 2004 at 35 million cubic feet.

Quicksilver, with a land base of 525,000 net acres, has budgeted US$89 million for Canada this year, the bulk going to coalbed methane.

—GARY PARK, Petroleum News Calgary correspondent

CANADA

Quebec LNG proposal joins Canada lineup as number four

Canada's list of candidates for liquefied natural gas terminals has grown to four, with a proposal for Quebec joining those in Nova Scotia, New Brunswick and British Columbia.

Robert Tessier, chief executive officer of Quebec utility Gaz Metro, told reporters at a Quebec-New York Economic Summit on May 13 that a C$700 million terminal could open near Quebec City in 2008 with capacity to process 500 million cubic feet per day.

He said Gaz Metro would be one of the buyers from the terminal, with the rest of the gas sold under contract, primarily in the U.S. Northeast.

The partners are Gaz Metro, French government-owned Gaz de France and Canadian pipeline company Enbridge, although Tessier would not say what the breakdown is.

The group is currently meeting with landowners and regulatory authorities, with the hope of filing regulatory applications in 2006, Tessier said.

He said the plant, if it gains community support and regulatory approvals, would be built across the St. Lawrence River from New York state. Gaz de France would secure the gas supplies and build ships to transport it to the terminal.

Enbridge, like Canada's other major pipeline company TransCanada, views LNG as a natural part of its business and has been on the lookout for opportunities in Canada and the United States.

—GARY PARK, Petroleum News Calgary correspondent

● ALASKA

The deal of last resort

Harold Heinze of Alaska Natural Gas Development Authority says the group's liquefied natural gas proposal keeps alive a number of different project options

By KRISTEN NELSON

Petroleum News Editor-in-Chief

The Alaska Natural Gas Development Authority is the only entity actively working on a liquefied natural gas project, the authority's chief executive officer, Harold Heinze, told Petroleum News in a May 3 interview. While the Alaska Gasline Port Authority has LNG as part of their proposal — along with a highway pipeline to the Lower 48 — the port authority's study is done, Heinze said, leaving the development authority the only group actively working an LNG option. The North Slope oil producers studied an LNG option in the late 1990s, but abandoned it in favor of taking gas to the Midwest by pipeline.

1 2 3 SERIES

LNG project offers different options

The LNG project, he said, offers a number of different options: It is 2 billion cubic feet of gas a day, which only requires a life-time supply of a little more than 20 trillion cubic feet, an amount available at Prudhoe Bay — without gas from Point Thomson or any other field.

"If I get gas here cheaper, that's good. If I get gas to Chicago cheaper, that's not necessarily good. I don't get points for Chicago. I get points for here." —Harold Heinze, Alaska Natural Gas Development Authority CEO

"We calculate you only need one producer and the state of Alaska to do it. If two people sat it out, you're still okay."

The other difference, he said, is that with LNG projects, customers historically have invested "back into the system," where with gas pipelines historically they have not.

So with an LNG project there could be "a major source of equity investment" that would never think of investing in a gas pipeline.

see DEAL page 18

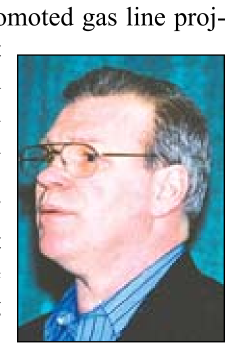
● ALASKA

Alaska gas authority wants more attention from governor

By LARRY PERSILY

Petroleum News Government Affairs Editor

Several board members of the Alaska Natural Gas Development Authority say the governor and his administration are giving more attention to a municipally promoted gas line project than the state's own effort to build a publicly owned pipeline from the North Slope. (See related story on page 19.)



SCOTT HEYWORTH

"I'm not feeling the love," said board member Scott Heyworth. "Once in a while it'd be nice to hear something from the governor about us."

Board member John Kelsey also complained about the lack of recognition.

"Do you feel the heat, Steve?" Kelsey asked of Steve Porter, deputy commissioner at the Department of Revenue and the administration's liaison to the state gas authority.

Alaska voters approved a citizens' initiative in November 2002 to establish the state gas authority, with the job of presenting a project plan to the Legislature later this year for a state-owned line to Valdez for exporting liquefied natural gas to U.S. West Coast and Far East markets.

Board members at past meetings have discussed their frustration at the slow pace of funding for their effort; the initiative did not say how to pay for the authority's work. Counting the money approved by the Legislature before its May 11 adjournment, lawmakers and the administration since last spring have earmarked $1.25 million for the authority's planning and feasibility work — about half what the board requested.

Press release prompted discussion

What started the board discussion at its May 10 meeting in Anchorage was Gov. Frank Murkowski's May 7 press release praising the work of the Alaska Gasline Port Authority, the consortium of the Fairbanks North Star Borough and city of Valdez created in 1999 to build a municipally owned gas line. The state and port authority this month signed an information-sharing

see ATTENTION page 17

● ALASKA

Small vs. large in gas pipeline debate

Other project hopefuls question Enbridge pitch for smaller Alaska gas pipeline

By LARRY PERSILY

Petroleum News Government Affairs Editor

Enbridge Inc. is in the minority among North Slope natural gas line proponents in its view that smaller is better when it comes to the project's pipe size to Alberta, but there is agreement that existing take-away lines could have a lot of excess capacity next decade to deliver Alaska gas across North America.

That available capacity could mean cost savings if Alaska gas can move to Pacific Northwest, Midwest and East Coast markets without building as much new pipe from Alberta, where the proposed North Slope line would enter the North America distribution system.

The first issue, however, is getting the gas as far as Alberta, something Alaskans have been waiting 30 years to see happen. The state may realize its dream in the next decade if North Slope producers and other companies such as Enbridge decide tight gas supplies and high prices justify the risky multibillion-dollar investment.

Enbridge, a Calgary-based pipeline and gas distribution company, believes there is less risk is building a 36-inch pipe to carry Alaska gas to Alberta than venturing into the uncertain world of 52-inch pipe. No pipe that large, pressurized at 2,500 pounds per square inch, has ever been built in North America, said John Carruthers, vice president for upstream development at Enbridge Pipelines Inc.

"We believe a single, large-diameter pipeline is the most promising project." —BP spokesman Dave MacDowell

The major North Slope producers, however, favor a 52-inch line, capable of carrying 4.5 billion cubic feet of gas per day. Enbridge has proposed a single 36-inch line at 2.6 bcf, followed by a second 36-inch line if market demand and gas supply justify the expansion.

It's a trade between cost and risk

The trade-off for building with easier-to-handle, easier-to-manufacture smaller pipe is a slightly higher tariff, Carruthers told the Alaska House Resources Committee May 6. The company estimates — and he made it clear it is only a preliminary estimate — that building twin 36-inch lines could add about a dime per thousand cubic feet to the tariff vs. constructing the Alaska line with a single 52-inch pipe.

"We are saying there is a competitive alternative," he said.

But Enbridge also acknowledges it may not have the right answer, Carruthers said. "I would think you would want to seriously consider the others."

BP Exploration (Alaska) Inc. has considered building a smaller line and believes larger is better to hold down the tariff, said company gas project spokesman Dave MacDowell. "Even 10 cents matters. Pennies matter."

A dime more in tariff charges per mcf on a project carrying 4.5 bcf per day could mean $164 million a year in higher transportation costs and an equal amount deducted from the wellhead value of the gas. However, the higher cost of twin smaller pipes could significantly reduce the risk of construction cost overruns from being the first project to use 52-inch pipe, while also helping to lessen the concern of oversupplying the gas market in the early years.

BP and North Slope production partners ExxonMobil Production Co. and ConocoPhillips Alaska Inc. spent $125 million in 2001-2002 on engineering and designing a pipeline to move Alaska gas to market. That work focused on a 52-inch line for the economies of scale in moving a larger volume of gas.

Producers prefer larger pipe

"We believe a single, large-diameter pipeline is the most promising project," MacDowell said in a May 18 interview. "Our focus is on identifying the project with the lowest transportation cost."

see **DEBATE** *page 20*

continued from page 16

ATTENTION

protocol to assist the municipalities' efforts in putting together a project for moving natural gas from the North Slope to Lower 48 and Far East markets.

The port authority signed the protocol in lieu of continuing formal negotiations under Alaska's Stranded Gas Development Act, which allows project developers to bargain for a long-term fiscal contract with the state in lieu of any taxes on the pipeline.

The Stranded Gas Act, however, isn't that relevant to the port authority because it is already exempt from state and municipal taxes, as is the state gas authority.

The Murkowski administration is trying to work with the port authority, the state gas authority, North Slope producers and Canadian pipeline companies Enbridge and TransCanada, all of which either want to build an Alaska gas line or at least have a stake in whatever deal is put together.

The port authority, however, "is sort of a stepchild," said Heyworth, the main sponsor behind the ballot initiative that created the state gas authority. The state authority "is the first-born son, I know that to be the fact," he said. Yet the port authority got a protocol and press release, Heyworth said.

Perhaps the state gas authority needs to go ahead and file a Stranded Gas Act application to attract the attention it deserves, said Kelsey, who serves on both the port authority and state gas authority boards.

Board sees role in supplying Cook Inlet

In further discussions, the board talked about its role in ensuring that any pipeline includes a spur to feed gas to Cook Inlet communities worried about possible supply shortages for residential and industrial needs by the end of the decade. Again, the Fairbanks-Valdez port authority came into the discussion.

"I don't believe the Cook Inlet area is prepared to leave its fate in the hands of the city of Valdez and Fairbanks (borough)," said Harold Heinze, chief executive officer of the state gas authority. The state board's membership includes six businessmen from Anchorage and Kenai and one from Fairbanks.

Board Chairman Andy Warwick directed his closing comment to Deputy Commissioner Porter: "Maybe you can get the governor to hug us occasionally."

In other action May 10, the board discussed its worries that the federal Jones Act, which requires U.S.-built and U.S.-crewed ships for carrying cargoes between domestic ports, could hurt its price competitiveness for moving LNG to West Coast markets. Heinze's own estimates show U.S.-built LNG tankers would cost twice as much as foreign vessels.

"It may be the deal killer," Warwick said.

"We need to be figuring out, how do we deal with this Jones Act," said board member David Cuddy.

Federal shipbuilding subsidy a possibility

Although the board discussed the option of seeking a congressional waiver from the Jones Act, Cuddy and Warwick suggested a federal shipbuilding subsidy might be a politically better way to go, especially by promoting the creation of U.S. shipyard jobs.

"Congress always goes for what costs more money and pleases the most people," Cuddy said.

The board approved a work plan that includes about $25,000 for a consultant to assist in finding possible solutions to the Jones Act problem.

Heinze and Heyworth suggested one approach they said is worth looking into. Perhaps the hull and propulsion system could be built in U.S. shipyards, then move the unfinished tankers to lower-cost yards overseas for installation of the LNG tanks and other systems.

The state gas authority estimates it would need three tankers to serve the West Coast, though Heinze was clear in stating the authority would not own the ships. The state could contract for use of the tankers, or perhaps the buyers of the gas could put the ships under contract. ●

continued from page 16

DEAL

"So, again, even if it's third on the list in terms of rewards to Alaska or economics or whatever — it's worth keeping your options open as long as it's feasible."

And that, said Heinze, is what the report at the end of summer will say: that basically the project is feasible.

"It won't claim it's the best project. It will say there's a lot more work to do before you'd actually spend big money on this, but it's still there, keep it moving forward."

As for a bullet line to Cook Inlet, a 30-inch line to bring North Slope natural gas to Cook Inlet, if nothing else works out, "maybe we ought to take a hard look at that — maybe that's like building a highway."

The only state corporation in the game

As for what benefit the development authority could bring to a project, it is "the only guy in the game who is the state's public corporation. And if at the end of the day, that's not worth anything, we're done."

The development authority is unique among the wannabes, and its work is to figure out what that could mean in a project.

They have received preliminary advice from the tax attorney on the utility idea, confirming that "as a utility of the state of Alaska performing a transmission function of gas" to Southcentral, "you're part of government, you're just a government utility, of course you're tax exempt and tax free."

As a utility, Heinze said, the development authority could act as an aggregator, procuring large supplies on the North Slope and selling that gas to multiple buyers at the other end.

It would have to be economic, he said, but it wouldn't have to make a profit. It would be "like building a highway," it would just be "part of the gas infrastructure."

It's what Enstar does: buy at one end, sell at the other.

But the development authority, as a state entity, would guarantee the lowest cost of service.

"Whatever margin, whatever advantage, whatever thing I can bring to the party, I can spend it for the benefit of Alaskans. If I get gas here cheaper, that's good. If I get gas to Chicago cheaper, that's not necessarily good.

"I don't get points for Chicago. I get points for here," Heinze said.

Has to be market tested

The Legislature is covering the costs of work the authority is doing on its feasibility report.

But, he said, if it comes to spending hundreds of millions of dollars to build a line — those aren't hundreds of millions of dollars the state should spend.

"The only way we see to avoid making a mistake is to treat it as a commercial transaction. In other words, we're not going to build something because the state thinks it's a good idea. The market needs to think that — the commercial entities need to think that."

If, someday down the road, a state project is ready for financing, investors have to believe the project is worth doing. The state won't be asked to build a project.

"We're going to bond this. No matter how you think about this, you can't sell bonds to folks unless they believe in the project," he said.

"If we can't make this work on commercial terms, even though we're part of the state, it's not worth doing."

Relative cost of projects

Heinze said one thing he's concerned about as the state considers different projects is that it is given good numbers and that it can compare apples to apples for different projects.

"The line I used — and I mean it — is we don't want the biggest liar to win. We have to be able to see enough that we can compare these things, apple-apple, and we have to at least be aware if there's a range of opinion, what that range is," he said.

There's enough information public now, he said, to do some rough comparisons for different projects, based on calculating the cost for inch-diameter-mile, the pipeline cost divided by the diameter and the number of miles.

Heinze said he would expect the numbers for a fairly good range of pipe sizes to be about the same, but "in this case we've got a range of about five or six — and that seems like a wide range to me."

MidAmerican, now out of the running, came in at the most expensive, $177,000 per inch-diameter-mile, compared to the latest producer numbers for the highway at $114,000 per inch-diameter-mile and the actual cost of the Lower 48 Alliance Pipeline at $34,000 per inch-diameter-mile. This, Heinze said, is "the last big major large-diameter pipeline built by the industry."

The state has been using $140,000 per inch-diameter-mile, a number arrived at separately by Purvin & Gertz in 2000 and by Yukon Pacific. Enstar, which builds pipelines in Alaska, estimates $66,000.

The producers' most recent number calculates out to $114,000, Heinze said, a 20 percent drop from the $140,000 everyone's been using.

"I corrected my estimates instantly for that — I don't get many 20 percenters," he said.

Heinze using producers' pipeline cost estimate

Heinze said he's not suggesting that there is anything wrong with any of the numbers.

"There may be different conditions behind each of the numbers."

But, he asked, if MidAmerican hadn't withdraw its application, how could the state compare projects with costs varying from $177,000 to $114,000 "for doing the same exact thing?"

Heinze said he's using the $114,000 and scaling it down for his smaller pipe because the companies spent $125 million studying the project, and "I presume some large portion of that was on this issue."

And so much of the project is the same.

"There's no difference in pipelining from Prudhoe Bay to the border than there is from Prudhoe Bay to Valdez… The first 530 miles is identical; the last 200 miles ain't that different."

But, he said, he wants to know how much "give" there is in the producers' estimate, because the state needs to understand the range of what's in the numbers. Costs change — as a recent increase in the price of steel — and without knowing specifics about how the producers got to the $114,000 it isn't possible to know how the estimate will change as individual costs change, he said.

BP says liquefaction costs coming down

Another cost Heinze has factored into his project cost is recent numbers from BP which show dramatic decreases in the cost to build liquefaction facilities, with costs dropping almost in half just in the last few years.

If the numbers are right, and if they apply to Alaska, Heinze said, "it dramatically affects the economics."

The five mega-majors are now all involved in LNG, he said: "You bring to bear that amount of smart money and they're going to figure out how to do some things better." It may be, he said, that with bigger LNG trains with bigger turbines the cost per ton of capacity drops.

"If it's bigger trains, bigger turbines, then we can use that" in Alaska, he said.

There are a number of trends, things changing dramatically, and we need to understand them, he said.

"I don't want to design an LNG plant. I just want to know if it's going to cost $2 billion, $3 billion or $4! And I just want to know which of those numbers has the higher probability of being right."

Pipelining is another area where the cost has come down dramatically, he said, probably due to improved trenching techniques.

In addition to the rising cost of steel — which may be temporary or permanent — Heinze said the metallurgy of the pipe will be new. "The pipe they're using is the most advanced metallurgy there is. It has never been used on a major pipeline. This could be the first time."

With larger pipe, he said, you need stronger steel to hold the pressure. You can't just go to thicker steel because it's hard to weld properly.

"So it's a tradeoff of the actual metallurgy of the steel vs. the welding."

It's very advanced metallurgy, he said, "and you have to weld it under field conditions." And, of course, the welds have to be perfect — it's either 100 percent or basically it fails.

Looking at the technical issues

"There's lots of legitimate reasons all of us ought to try to think about some of this stupid technical detail," he said.

How do you look at technical issues?

You use the people banks use, Heinze said, the kind of firms bank hire when they look at plans for an LNG plant and have been asked to loan $2 billion and want to know, can they build it for that amount?

It's a service provided by high-expertise firms who do everything but design and build, and Heinze said he's identified two such firms, one a spin-off of Brown and Root, the other part of the old Stone Webster organization.

"If you're Qatar, and Exxon wants to cut a deal with you, you hire one of these guys to look at the deal from a technical point of view," he said. ●

● ALASKA

Summer target date for ANGDA report

Alaska gas authority hiring consultants to help with project plan

By LARRY PERSILY
Petroleum News Government Affairs Editor

As it works toward a summer target date for submitting its project development plan to legislators, the Alaska Natural Gas Development Authority has a list of 21 possible consulting contracts it wants to issue by the end of the fiscal year on June 30. (See related ANGDA story by Larry Persily on page 16.)

The authority has about $700,000 available for the contracts.

The 2002 voter initiative that created the state gas authority set a deadline for the project development plan one year after the board began its work. The seven-member board started meeting last summer, looking to put together a plan for a state-owned pipeline to move North Slope natural gas to Valdez and build a liquefaction plant to serve Pacific Rim markets. Board members meeting May 10 in Anchorage approved a work plan authorizing Chief Executive Officer Harold Heinze to spend almost 20 percent of the money on determining the cost, regulatory and other issues of a spur line to bring North Slope gas to Cook Inlet. Residential and industrial customers in Anchorage and on the Kenai Peninsula worry that declining Cook Inlet production could leave them woefully short of gas by the end of the decade.

Heinze reported to the board that he hopes to have the feasibility report on the main gas line and LNG project completed by mid-August, with a separate development plan for the Cook Inlet spur line completed at about the same time. Regardless whether it proceeds with the bigger LNG project, the state gas authority could function as a public utility, Heinze explained, bringing gas to multiple users in the Cook Inlet area.

Spur line plans on work list

If the North Slope producers and/or other companies decide to go ahead and build the main line to take Alaska gas into Canada for distribution throughout North America, the state authority still could take on the project of building just the spur line to bring some of the gas to Cook Inlet.

The estimated $125,000 in contracts for spur line cost estimates, financing, regulatory issues and a project coordinator are listed among the gas authority's priority work assignments, Heinze said. He had not awarded any of the contracts as of May 18, but expected to select the consultants soon to meet his August completion date.

Other priority contracts Heinze expects to issue soon are five consulting assignments, at an estimated $125,000 total, for plant concept design, project and permit reviews and a coordinator for the proposed LNG plant at Valdez.

Of the 21 proposed contracts Heinze presented to the board May 10, 14 are budgeted at $25,000, the threshold under state contracting rules for avoiding formal bidding procedures. At that level, phone solicitations are adequate, and no advertising of the contracts is required. Professional service contracts in excess of $25,000 require a formal competitive bid process.

Financial consultants

Heinze also told the board he wants to move quickly to award $100,000 in contracts for consultants to assist the authority in learning more about financing options and setting up a business structure to maximize its chances of obtaining tax-exempt status from the Internal Revenue Service. And he estimated the authority will need to spend $150,000 for consultants on tax issues, funding alternatives and other financial advice.

Other contracts on the list include analysis of markets for Alaska natural gas and dealing with federal Jones Act requirements for U.S. vessels to ship Alaska LNG to California markets.

Heinze also informed the board at the end of the meeting that he wants a "significant" raise. He was hired last summer at $78,828 a year. "I'm at the short end of the stick," Heinze said, referring to the $175 an hour the Legislature is paying its gas line consultant and the $3,500 a day the state is paying its lead negotiator in gas line talks with North Slope producers.

Board Chairman Andy Warwick appointed a subcommittee to review Heinze's salary. ●

● NORTH AMERICA

No undue delays for LNG projects, FERC says

Federal agency works to finish LNG safety report; consultant says difficult to predict fire potential from spills

BY LARRY PERSILY
Petroleum News Government Affairs Editor

The Federal Energy Regulatory Commission says it will not "unduly" delay any of the dozen pending applications for new liquefied natural gas receiving terminals along U.S. shores as it works toward a final report on LNG safety risks.

FERC issued a consultant's report May 13 on the risk of fire and explosion from LNG tankers coming into port or tied up at a dock, specifically looking at how much damage could result if terrorists were able to blow a hole in a ship and its gas storage tanks.

The commission's final report on LNG tanker safety is expected by the end of the year, FERC Commissioner Joseph Kelliher said at a natural gas conference in Denver. Until then, the federal agency would hold off approving any new terminals, he told Dow Jones Newswires, although a commission spokesman later clarified FERC's position that it would not unduly delay approval of any pending applications.

The commission's final report on LNG tanker safety is expected by the end of the year, FERC Commissioner Joseph Kelliher said at a natural gas conference in Denver. Until then, the federal agency would hold off approving any new terminals, he told Dow Jones Newswires, although a commission spokesman later clarified FERC's position that it would not unduly delay approval of any pending applications.

The agency is accepting public comment on the consultant's report until May 28.

Lack of information makes modeling difficult

The report, prepared by Houston-based ABSG Consulting Inc., said it is difficult to predict the effects of an LNG spill for several reasons:

- "No models are available that take into account the true structure of an LNG carrier, in particular the multiple barriers that the combination of cargo tanks and the double hulls in current LNG carrier provide.
- "No pool spread models are available that account for wave action or currents.
- "There is no data available for spills as large as the spills considered in this study."

But, after stating those caveats, the report said an LNG tanker could catch fire and even explode, threatening people three-quarters of a mile away if terrorists were able to breach a ship's double hulls and also its cargo storage tanks. Under some conditions, the report said, a gas leak could create a flammable vapor cloud that would, at the right mixture with air, ignite and travel several thousand feet before dissipating.

"It suggests that some of the accident scenarios involve enormous fires that could cause deaths, severe burns to people several thousand feet away, and hot enough to burn wood and melt steel closer in," said U.S. Rep. Edward J. Markey, D-Mass., whose district includes the DistriGas LNG facility at Everett, Mass.

LNG tankers were temporarily barred from Boston Harbor and the Everett facility after the Sept. 11, 2001, terrorist attacks in New York City and Washington, D.C., and opponents of LNG terminals proposed for the East, West and Gulf coasts worry the new facilities could make their communities the target of terrorist attacks.

Maybe a dozen new terminal predicted by 2025

In addition to the 12 pending FERC applications for new LNG terminals, developers have proposed more than two dozen other sites to receive shipments of imported gas to meet America's growing supply shortage. Most proposals, however, are expected to die off in the face of community opposition and/or economics. International oil and gas consulting firm Wood Mackenzie Ltd. expects the nation could see perhaps seven new terminals by 2010-2012, and the U.S. Department of Energy expects as many as a dozen by 2025.

The ABSG Consulting report for FERC noted that although communities worry about the risk of LNG spills and fires, the industry has a good record: "These vessels have a remarkable safety record and provide an essential link in the movement of LNG from production locations to consumer locations."

The report said the lack of research and proven "pool spread models" make it difficult to predict how much gas would spill out of a tanker, whether it would ignite or disperse, and how far any damage might extend.

"Clearly, there is an opportunity to develop pool spread models that consider more realistic analysis of the spill behavior on the water surface," the report said. "Large-scale spill tests would be useful for providing better data for validation of models.

"It is also important to note that this study addresses the potential consequences of large-scale LNG cargo releases without regard to the sequence of events leading to such an incident or their probabilities of occurrence. As such, this report does not and was not intended to provide a measure of risk to the public."

FERC, in its final report later this year, will attempt to model the risk that comes with allowing more LNG tankers and receiving terminals in the country. ●

continued from page 1

SALES

Petro-Canada only Foothills bidder

In the Foothills areawide lease sale, Petro-Canada (Alaska) Inc. was the only bidder, taking five tracts at $5.37 an acre, for a total of $154,656. Petro-Canada is already a major leaseholder in the North Slope Foothills, and the tracts it took in this sale area adjacent to leases the company already holds.

Mark Myers, Department of Natural Resources Division of Oil and Gas director, said the Foothills bids covered approximately 28,800 acres.

78 bids in Cook Inlet sale

Myers said the state received 78 bids for 72 tracts in the Cook Inlet sale, approximately 363,520 acres. "This is the most interest we've received in a Cook Inlet sale since Sale 49 which was held in 1986," he said.

Major bidders in the Cook Inlet sale included newcomer Pioneer Oil with a total high bonus bid of $793,152 (27 tracts), followed by Alliance Energy Group at $486,128 (three tracts), Marathon Oil at $424,012.80 (11 tracts), Unocal at $386,585.60 (seven tracts), Forest Oil at $232,172.80 (nine tracts), Escopeta Oil & Gas at $162,956.80 (seven tracts) and Aurora Gas at $98,183.20 (three tracts).

Eighteen of the tracts Pioneer took are west of Knik Arm, across from Anchorage, from north of Point MacKenzie to southwest of Wasilla. The other block of tracks Pioneer took is on the west side of Cook Inlet, inland from Trading Bay and west of Aurora's Nikolai Creek gas field.

Bill Van Dyke, Division of Oil and Gas petroleum manager, said there were old wells in the area west of Knik Arm, drilled looking for oil. "I'd say it's probably more a gas-prone area," he said, based on the regional geology. Van Dyke said the other Pioneer Oil block, north of Trading Bay, is probably also a gas area, based on what companies like Pelican Hill and Aurora are doing in the area.

Other companies, he said, appeared to be bidding in areas where they have interests. "Marathon's been real active up in the Kenai-Sterling area, and that's where they bid, and Unocal, of course, has been real active on the southern peninsula, where they bid."

Myers said afterwards that it was a very good sale for the state, and that he was pleased to see a new player, Pioneer Oil, and was also pleased to see "the Unocal and Alliance folks filling in down by Anchor Point area" along the Ninilchik,

see **SALES** *page 22*

Want to know more?

If you'd like to read more about Enbridge, go to Petroleum News' web site and search for these articles, which represent only a few of those published in the last year.

Web site: www.PetroleumNews.com

2004
- **May 9** Enbridge proposes smaller line for North Slope gas
- **April 25** TransCanada to reactivate 23 year old Alaska gas....
- **April 18** Oil sands pipeline plans waver
- **March 14** Yukon-NWT still at odds
- **March 14** BP Canada exec says Alaska gas line filing....
- **Feb. 29** Trying Imperial's patience
- **Jan. 25** Terasen toys with trust
- **Jan. 4** Alberta eager to aid flow of Arctic gas
- **Jan 4** Canadian pipelines chase U.S. markets

2003
- **Aug. 3** Enbridge on Rocky Mountain high
- **July 7** Enbridge wants to build gasline ... to Chicago
- **June 1** Enbridge takes trust route
- **May 18** TransCanada locks up Foothills....
- **May 18** Enbridge puts focus on Arctic liquids

continued from page 1

INSIDER

price of crude (allowing for inflation) was the equivalent of $80 a barrel in 2004 dollars.

Even more crippling to global economies, it had more than doubled from the $40 average that lasted through the previous five years in the wake of the first OPEC oil embargo.

And OPEC's debut on the world stage in late 1973 triggered a four-fold surge in oil prices.

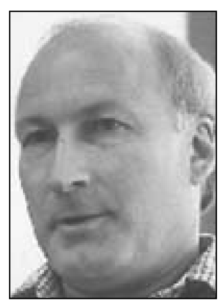
The reliance on oil by modern economies is far less than it was in the early 1980s: the energy needed to achieve $1 worth of gross domestic product is about half what it was then.

The International Energy Agency has calculated that oil has to climb by $10 to trim 0.5 percent off the world GDP growth over the net year, while the International Monetary Fund estimates the potential cost at 0.6 percent.

Even at that size, such an impact would create only a modest ripple if GDP is growing by 5 percent a year.

Hansen leaves Alaska DNR after 24 years

JIM HANSEN, the Alaska Department of Natural Resources Division of Oil and Gas leasing manager, attended his last lease sale as a state employee May 19. Mark Myers, director of the Division of Oil and Gas, said before the lease sale that Hansen, who as worked for DNR for 24 years, "first as the manager of resource evaluation, but now as the leasing manager." Myers said "Jim was sort of our icon of leasing — he is the one responsible for implementing the areawide leasing that's been so successful since '98."


JIM HANSEN

Hansen said that he's been on the leasing side for about 12 years, and said he would miss the lease sales. "It's been a great ride. As of August first I'm a free man," and said he might be sitting in the back, watching next fall's lease sales.

Queen of the oil patch called to head office

She came, she saw, but she didn't quite have enough time to conquer.

Barely a year after taking over the helm at Shell Canada, Linda Cook is now packing her bags to assume control of Royal Dutch/Shell Group's global natural gas and power unit and join the committee of managing directors.

The appointment must still be ratified at the annual shareholder meeting on June 28.

But if Cook leaves she will be replaced at Shell Canada, which is 78 percent owned by Royal Dutch/Shell, by Clive Mather, a 35-year company veteran who is currently chairman of Shell UK.

Kansas-born Cook, 45, was the first woman to head a major Canadian oil and gas company and seemed destined to spend several years in the Calgary head office steering the company's fortunes in the Mackenzie Delta, Alberta oil sands and Nova Scotia offshore.

All that was before the parent company was dragged into a reserves-accounting scandal that claimed the jobs of Chairman Philip Watts and exploration head Walter van de Vivjer, among others.

Cook, who has yet to comment on the promotion, said recently that the scandal "impacts all of us when there's a hit on your reputation like that. It will take years now to restore our reputation to the place we think it should be and the place where we would all want it to be."

Cook herself caught some of the backwash from the parent company's troubles. She was a member of the exploration and production executive committee in 1998 and 1999 and was director, strategy, business development, responsible for the reserve reporting process.

But a spokesman for Royal Dutch/Shell said she "bore no responsibility for the difficulties created by the reserves issue."

—GARY PARK, Petroleum News Calgary correspondent

continued from page 17

ENBRIDGE

"Certainly we don't have the lock on good ideas," he added. "We are willing to consider credible ideas that result in a lower-cost pipeline system."

TransCanada Ltd., Enbridge's crosstown colleague in the natural gas pipeline business, also favors a larger pipe, though not quite as big as the producers' proposal. "We've been advocating all along that the 48-inch pipeline is the answer," said TransCanada spokesman Kurt Kadatz.

TransCanada, which has said it will soon join the North Slope producers and Enbridge in submitting its own gas line project application to the state, already has 48-inch pipe as part of its Alberta system and its Canadian Mainline system that runs east to Ontario and upstate New York.

And TransCanada will have a lot of room in its pipeline systems to accommodate Alaska gas. "By around the neighborhood of 2012," Kadatz said, "we would expect to see 3 bcf of spare capacity in our Alberta System." The company's Alberta System carried 11.4 bcf per day in 2002, moving gas to the Montana border and pipes that fed upper Midwest, Great Lakes and New England states and Canada's eastern provinces.

Westcoast, Alliance also available

In addition to feeding TransCanada's lines, Alaska gas could find markets through Westcoast Energy Inc.'s system that carries gas from Alberta and British Columbia to the Washington state border, Enbridge's Carruthers said. He estimated the Westcoast line, owned by Duke Energy Co., could have 200 million cubic feet of available capacity by the time the Alaska line is in service next decade.

And the Alliance Pipeline, which last carried an average 1.6 bcf a day from British Columbia and Alberta to the end of the pipe near Chicago, could be expanded to carry an additional 500 million cubic feet, Carruthers said. Enbridge owns 50 percent of Alliance Pipeline. ●

Companies involved in North America's oil and gas industry

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

Petroleum news

Business Spotlight

By PAULA EASLEY

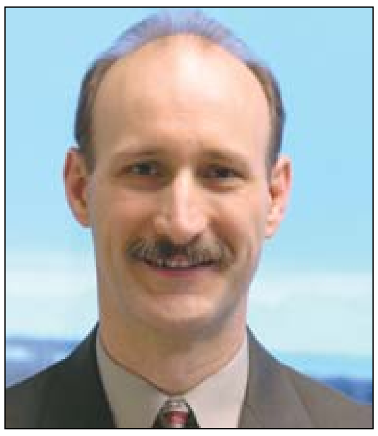
COURTESY OF HUNTER 3-D

Holly Hunter Huston, president

Hunter 3-D Inc.

Hunter 3-D is a geophysical consulting company based in Houston, Texas. The company provides 3-D seismic interpretation, prospect generation, gravity and magnetics 3-D modeling, and AVO analysis. The company also screens deals and evaluates producing properties for investors. For more info, go online to www.hunter3dinc.com.

Holly Huston founded the consulting firm with husband Dan Huston in 1996. Her education includes a master of science in geoscience, with emphasis on geophysics and field potential analysis. Holly enjoys working on projects all over the world and pioneering new technological advances with other geoscientists. Scuba diving, canoeing and growing prize-winning orchids are favorite pastimes. She knows from experience: "to err is human, but to really foul things up, you need a computer."



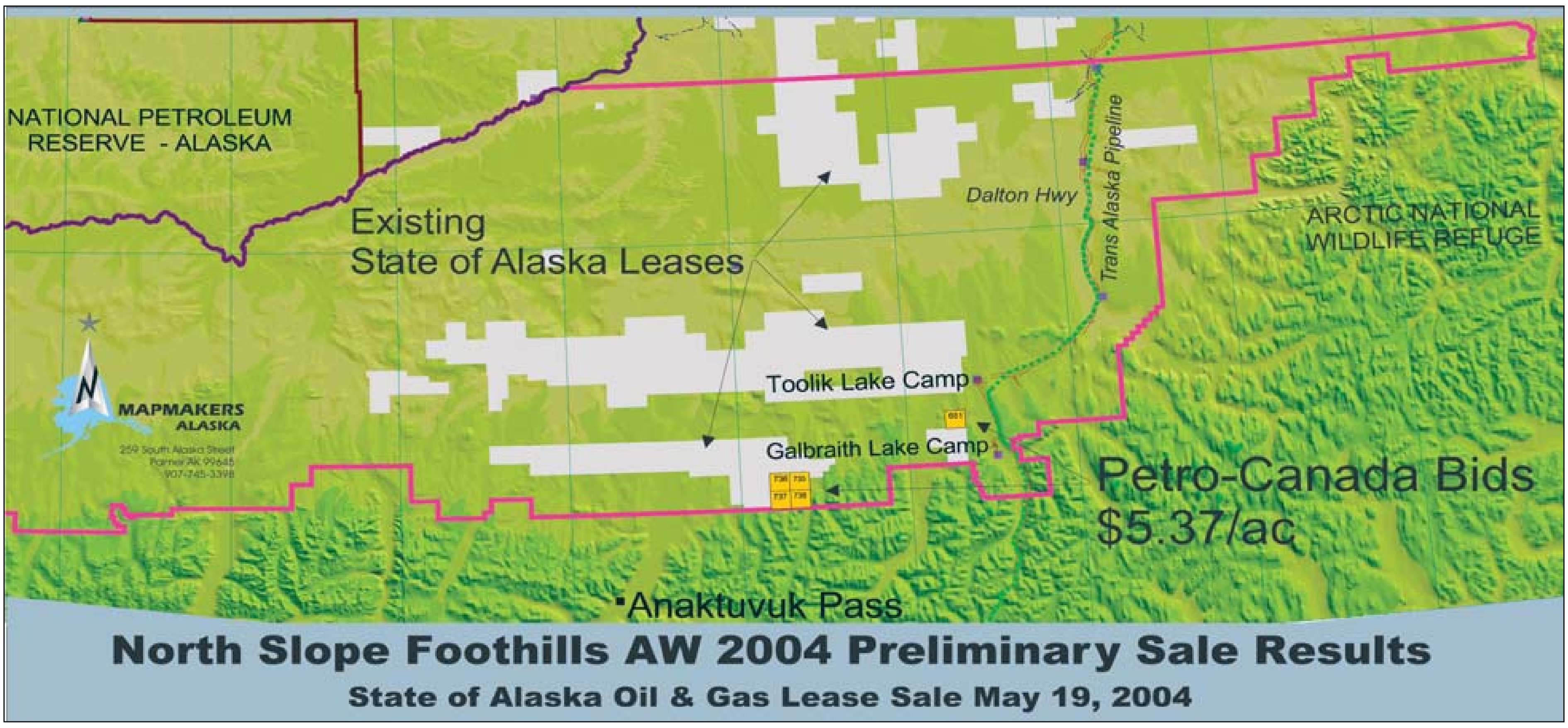
FORREST CRANE

Marcus McGarity, EVP, chief financial officer

ASRC Energy Services

ASRC Energy Services operates in Anchorage, Kenai, Deadhorse and Fairbanks. This growing conglomerate also maintains U.S. mainland and international operations. Primary services are engineering, construction, project management and maintenance/operations functions for a variety of energy and industrial clients. ASRC Energy recently contracted for government projects in Washington, D.C., Louisiana and Alaska.

After spending 10 years in construction and six in chemical manufacturing in Texas, Marcus McGarity joined ASRC. He spent one and a half years in a subsidiary and moved to AES last January; he is impressed with a workforce he finds "highly committed to excellence." Marcus married his high school sweetheart, Genine, and the couple has two children. In addition to church activities, Marcus supports children's aid organizations. He hopes to enroll, someday, in a European cooking school.



continued from page 20

SALES

Deep Creek trends.

Companies seemed to be filling in areas where they have interests, he said, including Aurora Gas and Forest on the west side and Escopeta with its offshore interests. "I think the pattern's very logical," he said.

Stiffest competition in Lower Cook Inlet

The highest per-acre bids in the sale were for five tracts on the lower Kenai Peninsula, in the area where both Unocal and Alliance Energy are developing natural gas fields. Nine tracts in this area received 13 bids, and of 10 bids in the sale for more than $10 an acre, six were in this area, including one losing bid.

Alliance paid the highest per-acre amount in the sale, $40.25 (with an estimated total bonus bid of $231,840) for tract 812, south of acreage the company holds surrounding its North Fork gas field east of Anchor Point, outbidding Monte J. Allen for the tract. Alliance also had the second highest per-acre bid, $36.50, for tract 799, on which it outbid Unocal. Tract 799 is just north of the company's North Fork acreage, and just west of Unocal's Nikolaevsk unit. Alliance also took tract 797, east of its North Fork acreage.

The highest per-acre bids in the sale were for five tracts on the lower Kenai Peninsula, in the area where both Unocal and Alliance Energy are developing natural gas fields.

Unocal had the third highest per-acre bid of the sale, $21.15, for tract 781 southwest of its Deep Creek unit, and paid $16.37 per acre for tract 800, just south of tract 781. Unocal took the most tracts in the area, five; Alliance took three; Aurora Gas took one.

Andy Clifford of Aurora Gas said Aurora is reforming an acreage position on the lower Kenai Peninsula that is part of what the company acquired from Anadarko Petroleum. Aurora picked up one of the lower peninsula tracts it bid on, losing the other to Unocal. Aurora also took two tracts on the west side of Cook Inlet, where it is a gas producer.

Clifford said Aurora is "chasing oil, not gas," on the lower Kenai. On the west side the company picked up a lease at the mouth of the Susitna River, a frontier area for the company, Clifford said, with only a little bit of well control and vintage seismic.

MMS receives no bids for Cook Inlet lease sale

The Minerals Management Service was to have held its Cook Inlet Sale 191 in conjunction with the state sales, but the agency said May 18 that it received no bids for the sale.

"Part of our job is to provide access to acreage, but companies then must decide whether it fits in with their exploration plans," MMS Alaska Regional Director John Goll said in a statement. Goll said "companies continued to express interest right up through the last few weeks," but no bids were received prior to the agency's May 18 deadline.

Goll said prior to the state sale that he hopes MMS can continue to hold sales in conjunction with the state.

"Regardless of what happened today, I want to reemphasize, though, that the Department of the Interior remains committed to offering acreage for exploration access into the future," he said.

MMS has proposed another sale for Cook Inlet in 2006. The last exploration well was drilled in the federal Cook Inlet outer continental shelf area in 1984, and the area remains relatively unexplored. ●

continued from page 4

PIONEER

June 6. He estimates it will be 2005 before Pioneer Oil drills the first hole on its Alaska leases.

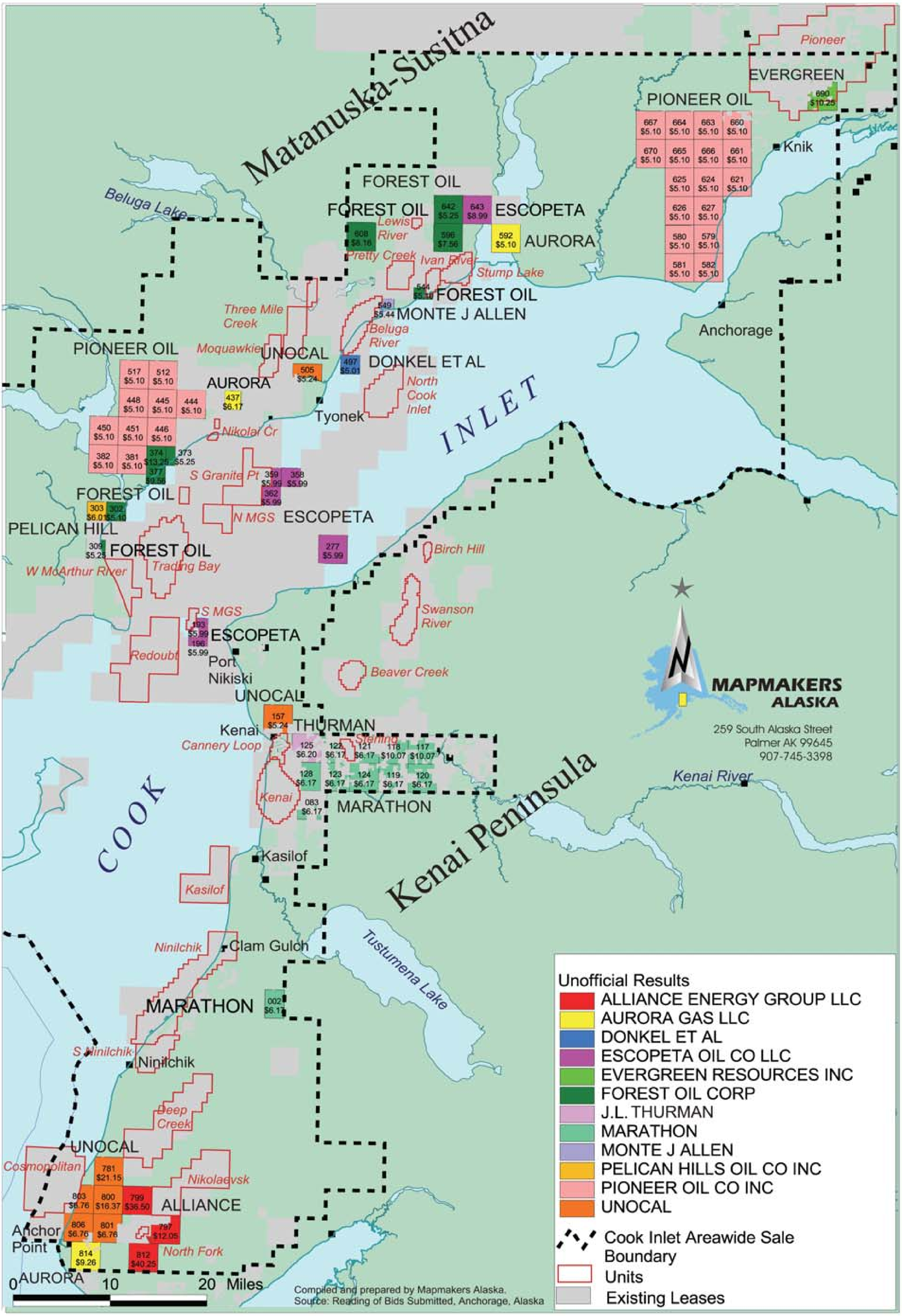
Pioneer Oil, an 'S' corporation, operates about 800 wells in the United States. According to company literature Roger Meier, the general manager of Pioneer Oil's sister company, Franklin Well Services, has supervised drilling operations on Alaska's North Slope while working for other service companies.

In addition to moving into Alaska, Pioneer Oil is hoping to expand into the oil business in the West African States and into Nevada where the company is looking at a conventional gas play.

Mark Myers, director of the Alaska Division of Oil and Gas, said he doesn't know very much about Pioneer Oil, "other that they are a company out of Illinois, and they operate several hundred wells, so they are an experienced oil and gas operator."

Myers said the state is pleased a new independent is coming into Alaska.

The areas where Pioneer Oil bid are "dominantly gas prone," he said. ●



UNOFFICIAL RESULTS
STATE OF ALASKA COOK INLET AREAWIDE 2004 OIL & GAS LEASE SALE
May 19, 2004

CH2M HILL...
Securing Our Critical Petroleum Infrastructure

CH2M HILL is trusted to secure some of the world's most at-risk and highly visible locations, including petroleum facilities, chemical facilities, private and public ports, 50 U.S. Department of Defense facilities, three large U.S. Department of Energy facilities, international airports, cherished national monuments and more than 100 water utilities across the nation.

IMPORTANT NOTICE!

New Security Requirements for Petroleum Facilities

If you own or operate a maritime facility engaged in international commerce (including terminals, vessels or off-shore operations), you will need to comply with the requirements of the Maritime Security Act by performing a Facility Security Assessment and developing a Facility Security Plan for the U.S. Coast Guard (USCG). Plans must needed submitted to the USCG by December 31, 2003. After review and approval, you must be in compliance with your authorized plan by July 1, 2004 or face potential fines of up to $10,000 per day.

At issue — the majority of the plans may not be approved, rejected, or even reviewed by the USCG by the July 1 deadline.

How can CH2M HILL help?

CH2M HILL is a leader in providing port security for both public and private ports. We have experience developing Facility Security Plans and rewriting existing plans to conform with USCG regulations. Key to our success is our knowledge of port infrastructure and operations. And, to help you fund the implementation of your plan, the Department of Homeland Security (DHS) has made grants available. The next round of grants is scheduled for the summer of 2004.

CH2M HILL's experience in helping our maritime security clients includes:

- **Intercontinental Terminals Co., Houston, TX** – Design, procurement, and construction of all elements of Transportation Security Act appropriation including cameras, intrusion detection, credentials, access control, and lighting for more than 8 million barrels of storage in 181 tanks connected to the Texas Eastern Pipeline
- **Nova Chemicals, Virginia Beach, VA** – Nova's security plan was rejected by the USCG. CH2M HILL has been hired to help Nova revise and submit a plan that will be approved
- **Port of Palm Beach, Florida** – Security management, engineering, and construction management services including the development and implementation of security training, security procedures, cruise terminal security compliance, and serving as the Executive Director's representative to all federal, state, and local law enforcement and regulatory agencies
- **Port of Corpus Christi, Texas** – Risk assessment and implementation support for one of our most strategic ports, spanning a ship channel 8 miles in length and housing multiple petrochemical refineries that provide nearly one-third of our nation's military and commercial aviation fuel
- **U.S. Virgin Islands Port Authority** – Developed passenger vessel security plans for cruise ports at Crown Bay in St. Thomas and Fredrikstad Pier in St. Croix, identifying operational, planning, logistics, and training requirements for each of the three designated Maritime Security Levels in accordance with U.S. Coast Guard and International Maritime Organization (IMO) guidance documents

CH2MHILL

www.ch2mhill.com

E042004010BDS

secure

secure

secure

For more information contact:

Doug Sethness *Director of Port Security, CH2M HILL*
Phone: 713.462.0161, dsethnes@ch2m.com

Kelly Sobczak *Alaska Petroleum Account Manager, CH2M HILL*
Phone: 907.646.0214, ksobczak@ch2m.com