Petroleum news

page 16 U.S. Senate approves energy bill; House battle ahead

Vol. 10, No. 27 • www.PetroleumNews.com *A weekly oil & gas newspaper based in Anchorage, Alaska* Week of July 3, 2005 • $1.50

Gas line contract by year-end

JUDY PATRICK

Jim Bowles, president of ConocoPhillips Alaska, was one of several oil company execs speaking at a June 27 luncheon in Anchorage where Alaska's governor and its oil and gas producers told attendees that negotiations are moving forward on a North Slope gas line contract. Bowles brought a large scale to the podium and used weights to illustrate his speech. See story on page 9.

Blowing hot and cold on Mackenzie gas pipeline project

For the Mackenzie Gas Project it's like a case of what you gain on the teeter-totter you lose on the roundabout.

On the upside, the Deh Cho First Nations have put their lawsuits against the Canadian government on hold in anticipation of a deal with the government.

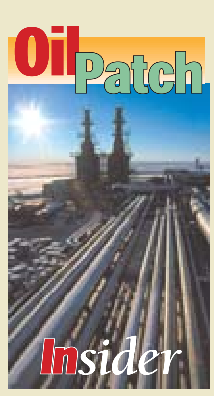
Hanging in the balance is the prospect of a federal-Northwest Territories pact to pay the costs of the Mackenzie pipeline's socio-economic impact.

On the downside, delegates to a June 26-29 environmental impact statement conference in Yellowknife say they still lack detailed information on the pipeline's impact in the Northwest Territories.

The conference was designed to help the Joint Review Panel decide if and when full-scale public hearings for the C$7 billion

see **MACKENZIE** *page 20*

EnCana says it's No. 1; New player in Alaska? Think Italian



WHEN GOV. FRANK MURKOWSKI announced June 28 that Alaska would soon have a new major player in the oil and gas industry, he kicked off speculation as to which oil company was about to enter the state.

"I can tell you that there's going to be a major announcement here very soon on a major player," he said at a luncheon in Anchorage, electing not to name the company: "when they're ready to announce it, you'll find out."

Much to the governor's dismay, Gregg Nady, Alaska land representative for Shell, made a speech right after his, essentially

see **INSIDER** *page 20*

BREAKING NEWS

4 CIGGS deal reached: Agreement in principle reached in Cook Inlet Gas Gathering System dispute; RCA gives parties time to finalize

5 Digging deep in Deep basin: Tight gas play in Canada reawakens Shell's interest in conventional E&P; technology plays role

11 Oil shale: Is it real, or just a mirage? Part 2 of 2; Various signs hint that shale oil's time may be closer than ever

HOUSTON, TEXAS

Drilling profits soar

Second quarter company profits expected to rise by 20% on tight rig markets

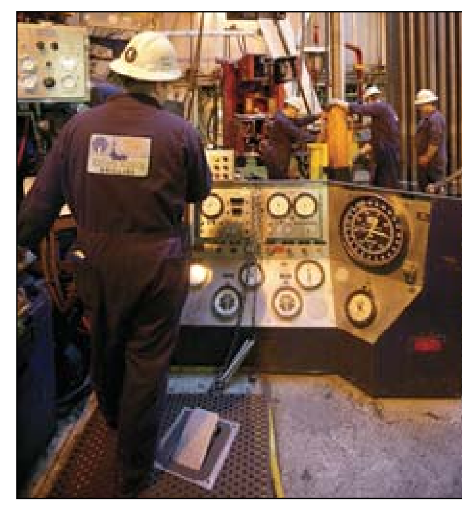
By RAY TYSON

Petroleum News Houston Correspondent

U.S.-based drilling contractors, after lagging the rest of industry through much of the run up in oil and gas prices, appear to be well on their way to the top, with 2005 second-quarter profits expected to increase nearly 20 percent on average from the previous quarter and a whopping four-fold compared to the same quarter last year.

The numbers are more amazing when considering that half of the 10 major drilling companies tracked by Petroleum News actually were losing money a year ago, when exploration and production companies were raking in cash on strong commodity prices but hesitant to expand drilling operations.

see **PROFITS** *page 22*



JUDY PATRICK

Crews at Nabors rig 33E drilling at Northstar Island for BP.

CANADA

Little guys on the run

Canadian juniors, trusts have to be quick on their feet to survive rapid turnover rate

By GARY PARK

Petroleum News Canadian Correspondent

The Canadian oil patch is in the thick of a Darwinian cycle as junior E&P companies and energy trusts do battle for a shrinking supply of assets.

Caught up in a swirl of mergers, acquisitions and restructuring, the sector is turning over at an ever faster rate.

A survey of first quarter results by Iradesso Communications, a Calgary-based research and investor relations firm, showed 20 of the all-time record 83 publicly traded juniors had been created in a six-month period, while 19 others had either disappeared in mergers or switched to the trust sector.

Peter Knapp, Iradesso president

The stable of 31 conventional energy trusts had grown by five in the same period.

Estimating the average lifespan of juniors at 30 months, Peter Knapp, Iradesso president, told Petroleum News that "everybody" was in a scramble to build, sell and start over again.

He said the motivation was a window of opportunity to take advantage of the commodity price cycle.

"Geologists, engineers and business people don't want to miss their chance to make big dollars while the commodity cycle is in their favor," he said.

see **RUN** *page 22*

LONDON

BP: No shortage of oil

Annual statistical review places high oil, gas prices into historical, global perspective

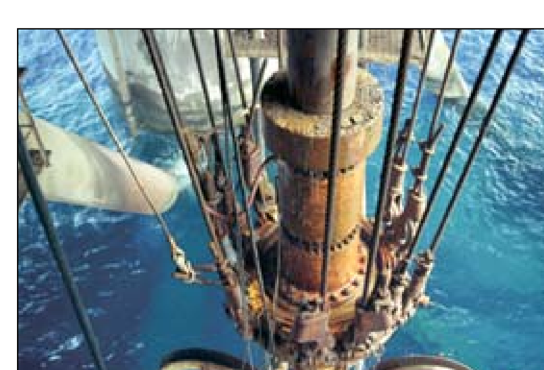
By ALAN BAILEY

Petroleum News Staff Writer

Every year British Petroleum PLC publishes its authoritative "Statistical Review of World Energy." And with sticker shock at U.S. gas pumps coupled with stories of pending oil shortages, this year's review sheds valuable light on what has been happening in world energy markets.

"The purpose of the review has always been to provide reliable, timely, unbiased energy market data," Mark Finley, BP's head of energy analysis, said at a June 24 media presentation in Anchorage. "… This data is the first comprehensive snapshot of what's happened in the world of energy in 2004."

The big story from last year turned out to be surging world energy consumption fueled by global economic growth, Finley said. In 2004 the world economy enjoyed its best year in 15 years, he said. And in tandem with that, world energy consumption grew by 4.3 percent — the highest annual percentage growth since 1984 and the biggest incremental rate ever in world energy consumption.



see **BP REVIEW** *page 23*

contents

Petroleum News *A weekly oil & gas newspaper based in Anchorage, Alaska*

Alaska - Mackenzie Rig Report

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status

Alaska Rig Status

North Slope - Onshore

Doyon Drilling			
Dreco 1250 UE	14 (SCR/TD)	Drilling, Milne Point, F pad MPF-93	BP
Sky Top Brewster NE-12	15 (SCR/TD)	Drilling, Kuparuk, well 1E-170	ConocoPhillips
Dreco 1000 UE	16 (SCR)	Workovers, N-08a	BP
Dreco D2000 UEBD	19 (SCR/TD)	Drilling, Alpine CD2-60	ConocoPhillips
OIME 2000	141 (SCR/TD)	Drilling, Kuparuk, 1E-117	ConocoPhillips
Nabors Alaska Drilling			
Trans-ocean rig	CDR-1 (CT)	Stacked, Prudhoe Bay	Available
Dreco 1000 UE	2-ES (SCR)	Prudhoe Bay, 06-20A	BP
Mid-Continent U36A	3-S	3H-14B	ConocoPhillips
Oilwell 700 E	4-ES (SCR)	Milne Point, MPF-38	BP
Dreco 1000 UE	7-ES (SCR/TD)	Prudhoe Bay, S-111i	BP
Dreco 1000 UE	9-ES (SCR/TD)	Niakuk Field, L-202	BP
Oilwell 2000 Hercules	14-E (SCR)	Stacked, Deadhorse	Available
Oilwell 2000 Hercules	16-E (SCR/TD)	Stacked, Prudhoe Bay	Available
Oilwell 2000	17-E (SCR/TD)	Stacked, Point McIntyre	Available
Emsco Electro-hoist -2	18-E (SCR)	Stacked, Deadhorse	Available
OIME 1000	19-E (SCR)	Stacked, Deadhorse	Available
Emsco Electro-hoist Varco TDS3	22-E (SCR/TD)	Stacked, Milne Point	Available
Emsco Electro-hoist	28-E (SCR)	Stacked, Deadhorse	Available
OIME 2000	245-E	Stacked, Kuparuk	Available
Emsco Electro-hoist Canrig 1050E	27-E (SCR/TD)	Stacked on 12-acre pad	Kerr-McGee
Nordic Calista Services			
Superior 700 UE	1 (SCR/CTD)	Drill site 18, well 12B	BP

North Slope - Offshore

Nabors Alaska Drilling			
Oilwell 2000	33-E (SCR/TD)	Cold stacked on NorthStar Island	BP
Nordic Calista Services			
Superior 700 UE	2 (SCR/CTD)	Kuparuk, 10 well 27	BP
Ideco 900	3 (SCR/TD)	Stacked, Kuparuk 1Q pad	Kerr-McGee

Cook Inlet Basin – Onshore

Aurora Well Service			
Franks 300 Srs. Explorer III	AWS 1	Rigging down Moquawkie No. 3, moving to Lone Creek 3	Aurora Gas
Pioneer Natural Resources			
Wilson Super 38	96-19	Stacked in Wasilla yard	Pioneer Natural Resources
Kuukpik	5	Stacked Kenai	Available
Marathon Oil Co. (Inlet Drilling Alaska labor contractor)			
Taylor	Glacier 1	KU24-7	Marathon
Nabors Alaska Drilling			
National 110 UE	160 (SCR)	Stacked, Kenai	Available
Continental Emsco E3000	273	Stacked, Kenai	Available
Franks	26	Swanson River, 314-04	Unocal
IDECO 2100 E	429E (SCR)	Stacked, removed from Osprey platform	Available
Water Resources International			
Ideco	H-35 KD	Stacking, Pre to MOB to Kenai	Pelican Hill

Cook Inlet Basin – Offshore

Cudd Pressure Control	340K	Stacked	Available
Unocal (Nabors Alaska Drilling labor contractor)			
Not Available			
XTO Energy (Inlet Drilling Alaska labor contract)			
National 1320	A	Idle	XTO
National 110	C (TD)	Idle	XTO

Copper River Basin

Nabors Alaska Drilling			
Rigmasters 850	129	Demobilizing to Kenai	Available

Mackenzie Rig Status

Mackenzie Delta-Onshore

AKITA Equtak			
Dreco 1250 UE	62 (SCR/TD)	Stacked, Tuktoyaktuk, NT	Available
Dreco 1250 UE	63 (SCR/TD)	Stacked, Lucas Point, NT	Available
National 370	64	Stacked, Inuvik, NT	Available

Central Mackenzie Valley

AKITA/SAHTU			
Oilwell 500	51	Moving to Alberta for Apache Canada	Available
RigMaster P-850	40	Moving out after drilling Sahcho L-71	Northrock Resources
Nabors Canada			
	62	Racked	Apache
	8	Stacked, Alberta	Apache

Yukon Territories Rig Status

Yukon

AKITA/Kaska			
National 80UE	58	Stacked, Fort Liard, NT	Available
Ensign Resources Svc. Grp.			
Jackknife Double	55	Drilling completed, racked in Ft. Nelson	Devon Canada

The Alaska - Mackenzie Rig Report as of June 27, 2005. Active drilling companies only listed.

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

This rig report was prepared by Alan Bailey


JUDY PATRICK

Baker Hughes North America rotary rig counts*

	June 24	June 17	Year Ago
US	1,370	1,358	1,176
Canada	257	222	334
Gulf	94	93	92

Highest/Lowest		
US/Highest	4530	December 1981
US/Lowest	488	April 1999
Canada/Highest	558	January 2000
Canada/Lowest	29	April 1992

*Issued by Baker Hughes since 1944

CARACAS, VENEZUELA

Venezuela claims world's largest oil reserves: 316B barrels — including tar

President Hugo Chavez believes his oil-rich Venezuela has the largest reserves in the world — and he plans to prove it.

In recent months, Chavez has repeatedly boasted that Venezuela's estimated 78 billion barrels in conventional reserves, coupled with an estimated 238 billion barrels of tar oil in the nation's so-called Orinoco Belt, "are the largest petroleum reserves in the world." By comparison, Saudi officials say Saudi Arabia has proven reserves of 261 billion barrels of crude.

Venezuela President Hugo Chavez

According to a statement released June 26 by the state-run oil company Petroleos de Venezuela S.A., or PDVSA, Venezuela's proven oil reserves have been underestimated because reserves from the Orinoco Belt were not included in previous studies calculating all the nation's oil reserves.

The heavy crude from the eastern Orinoco region, which was marketed as boiler fuel called Orimulsion, was not included in conventional oil reserves calculated by past governments because Orimulsion was designed to compete with coal — not oil — and excluded from production quotas established by the Organization of Petroleum Exporting Countries.

PDVSA plans to carry out a study that would include the Orinoco reserves in Venezuela's conventional oil reserves, according to the statement issued June 26.

The move marks a shift in policy with previous administrations in this oil-rich South American nation.

PDVSA has criticized past governments for selling Orimulsion at a fraction of the price of oil. It has started mixing the cheap boiler fuel with lighter crude to make it marketable and recognized as a part of Venezuela's total oil reserves.

Industry analysts have said Chavez's government wants to increase Venezuela's proven reserves as a means of regaining negotiating power within OPEC.

Venezuela, a major supplier of oil and gasoline to the United States, is currently producing below its OPEC quota and has no capacity to boost output, diminishing the country's influence in the cartel.

—THE ASSOCIATED PRESS

Petroleum news
www.PetroleumNews.com

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

EDITORIAL
Anchorage
907.522.9469

Editorial Email
Anchorage
publisher@petroleumnews.com
Canada
farnorth@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) • Vol. 10, No. 27 • Week of July 3, 2005
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. — $78.00 for 1 year, $144.00 for 2 years, $209.00 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.

● ANCHORAGE

Parties in CIGGS dispute reach agreement

Agreement in principle reached in Cook Inlet Gas Gathering System dispute; RCA gives parties time to reach final settlement

By KRISTEN NELSON
Petroleum News Editor-in-Chief

The Regulatory Commission of Alaska has accepted an agreement in principle reached by the parties to resolve outstanding rate and tariff issues for the Cook Inlet Gas Gathering System. The parties have 60 days to finalize the agreement.

Marathon Oil, Unocal, Agrium, the State of Alaska, Aurora Gas, Alaska Pipeline Co. and Enstar Natural Gas Co., the parties in the CIGGS dispute, notified the commission June 24 that they have executed a comprehensive agreement in principle "setting forth the principal settlement terms intended to resolve all outstanding rate and tariff issues" in two dockets before the commission.

Agrium U.S. Inc. filed complaints against Marathon and Unocal, owners of CIGGS, arguing that the pipeline should be regulated by the commission. CIGGS, which moves gas from the west side of Cook Inlet to the Kenai Peninsula, was built prior to Alaska statutes requiring regulation of such pipelines. The Agrium complaint, filed in October, said Marathon and Unocal are violating the Alaska Public Utilities Regulatory Act and the Alaska Pipeline Act by providing unregulated transportation service through CIGGS.

The parties told the commission they have a detailed plan for reaching a final settlement and asked for 60 days to draft and file the final settlement agreement with the commission.

In a June 27 order the commission agreed to vacate its existing procedural schedule to allow the parties to finalize the settlement. It said the parties had requested a procedural schedule for the commission's "consideration, acceptance, and approval" of the final settlement, and also requested that the commission allow interim transportation and approve interim terms and conditions.

The commission said it favors settlement of issues where possible, and noted that underlying issues in the CIGGS' dispute "are complex and difficult issues" that, in the absence of a settlement, would require "considerable resources" by both the commission and the parties "to resolve through litigation."

Agreement will get gas to market

The commission said it commends the parties for reaching an agreement in principle, and notes "that their agreement will allow trapped gas to be transported to market."

The parties have until Aug. 26 to finalize and file a final settlement agreement; a public hearing on the settlement is set for Jan. 25, 2006.

As part of the agreement in principle, the commission said that Marathon and Unocal will transport gas for third-party shippers beginning Nov. 1, "unless earlier agreed" by the CIGGS owners. This transportation will be on an interim basis until the commission approves the final settlement agreement or issues a final order.

The commission agreed not to use the interim agreement as the basis for asserting jurisdiction over CIGGS and also said interim access and terms cannot be used for any party as the basis for an argument that CIGGS is subject to the commission's permanent jurisdiction.

Marathon and Unocal will charge an interim rate of 1.52 cents per thousand cubic feet per day; third-party shippers will advance a deposit for use of the interim service, a deposit which would be "fully and immediately refundable" if the final settlement agreement is not approved.

"The fact of interim and conditional access to Cook Inlet Gas Gathering System under this Order and the commercial terms of the access will not be accepted as evidence in support of any party's advocacy position on any issue of law or fact to be resolved in these Dockets or in any future proceeding," the commission said. ●

SAKHALIN ISLAND

Indigenous groups block road to oil site

Dozens of representatives of small indigenous groups blocked a road leading to a Sakhalin oil site in the Russian Far East on June 28 to protest development plans they say will damage the environment and disrupt their traditional culture.

About 75 people blocked the Yuzhno-Sakhalinsk-Okha road on Sakhalin Island, said the regional Council of Small Indigenous Peoples.

Some of Russia's largest oil and gas fields are located off Sakhalin Island, which is more than 6,200 miles east of Moscow and some 430 miles north of Tokyo. Many multinational oil companies are currently working to tap the reserves.

—THE ASSOCIATED PRESS

ALASKA

ACMP amendments get preliminary nod

Alaska Gov. Frank Murkowski said June 28 that NOAA has issued preliminary approval for the state's amended Alaska Coastal Management Program.

"This is a victory for state's rights," the governor said in a statement, noting that securing approval of the changes "has been a long process."

The governor said a June 27 letter to Alaska Department of Natural Resources Commissioner Tom Irwin from the National Oceanic and Atmospheric Administration, Office of Coastal Resource Management, responded to the state and issued preliminary approval of the amendments to the ACMP. The agency said Alaska satisfied procedur-

see **ACMP** *page 5*

CANADA

Digging deep in Deep basin

Tight gas play in Canadian foothills reawakens Shell Canada's interest in conventional E&P; technology helps bring area to life

By GARY PARK

Petroleum News Canadian Correspondent

North American natural gas demand, robust commodity prices and the march of technology are combining to light up a Western Canada play that could hold vast riches.

Shell Canada gave the latest vote of confidence to Deep basin when it forked over C$85 million for 58,000 acres in northeastern British Columbia, doubling its holdings in an area straddling the British Columbia-Alberta border.

The Calgary-based company, 78 percent owned by Royal Dutch/Shell, is now gearing up for winter drilling as it plunges ahead with a strategy to grow its gas business in Western Canada.

How many wells remains an unknown at this time, but the company has hiked its 2005 exploration budget for the region by 30 percent to C$335 million from C$235 million in 2004.

Until recent times, the company had been phasing out of conventional oil and gas in the Western Canada Sedimentary basin.

But that retreat took a sharp about-turn last December when it posted the Tay River gas discovery in west-central Alberta — a find it now estimates could range from 650 billion to 850 billion cubic feet, one of onshore Canada's best finds in years.

Advances in seismic credited

Shell Canada credited that success to advances in seismic technology that are propelling a wave of interest in the "tight" gas potential of Deep basin, which extends from northeastern British Columbia and northwestern Alberta along the eastern foothills of the Canadian Rockies.

Over the past 25 years, geologists have calculated that Deep basin could have a gas resource of 400 trillion cubic feet, 10 times the remaining gas reserves in Alberta.

However, putting a figure on tight gas is such a guessing game that the National Energy Board has offered a range for all of Canada from 89 tcf to 1,500 tcf.

That reflects the difficulty of pinpointing with certainty gas that is trapped in hard-to-find sandstone or limestone formations.

To help better refine the resource, Time Seismic Exchange (a unit of VeritasDGC) expects to spend C$70 million this summer continuing a five-year program of acquiring 3-D seismic that will eventually cover about 3,400 square miles.

Tay River involved the use of Shell Canada's own seismic processing techniques that produce a clearer image of a geological feature it would not have been able to see previously.

Chief Executive Officer Clive Mather told the company's annual meeting in May that it would be "delightful" if the technology led to a "whole string of discoveries" in the area, although he cautioned that the chances of further discoveries remain speculative.

Recent remarks raise expectations

But in several public remarks recently, Mather has done more to raise rather than lower expectations for Deep basin.

He said data gathered from Tay River is being re-examined in hopes that more gas will be found in the region.

Mather told an energy conference in New York on June 23 that his company is determined to "really identify" what the Western Canada Sedimentary basin holds.

In the absence of any evidence to the contrary, "I think there is a lot more gas to be found," he said. Others share that sentiment.

In Deep basin alone, Talisman Energy landed a big prize in the British Columbia foothills last year with a deep well in the Monkman area that is now pumping 66 million cubic feet per day.

Talisman Chief Executive Officer Jim Buckee described that well as "one of the better exploration wells in the history" of the Western Canada basin.

He rates the western foothills as an "exciting area … we have a number of new exploration concepts we'd like to try there."

Talisman and Shell are also partners in another Monkman discovery that tested at 19 million cubic feet per day, while a Talisman well tested at a stabilized 16 million cubic feet per day.

Petro-Canada, ConocoPhillips Canada and Suncor Energy have also entered the foothills, where wildcatters expect to pay C$15 million-$18 million for a well (the Tay River well was drilled to 16,800 feet) and need access to experienced crews and the best equipment.

Gas prices help

What helps is gas prices in the C$7 per thousand cubic foot range and the growing supply-demand imbalance in North America.

E&P companies are also faced with handling gas that has high levels of hydrogen sulfide. The Tay River find had an H2S level of 35 percent, but Shell has access to underutilized processing plants in the area.

EnCana's Cutbank Ridge and Greater Sierra plays fall into a similar category to Deep basin, with deep and complex gas deposits.

They are a key element of EnCana's resource portfolio, producing a combined 250 million cubic feet per day in the first quarter and having combined unbooked resource potential of 3.7 tcf.

Canadian Natural Resources has also logged success in northeastern British Columbia, currently producing 450 million cubic feet per day from its properties in the region.

The June land sale that was dominated by Shell pumped C$100 million into British Columbia government coffers, making it the third largest in provincial history.

Energy Minister Richard Neufeld said the response was further proof of British Columbia's under-drilled potential.

He noted that the northeast totaled 1,300 wells in 2004, compared with 15,000 in Alberta, but the average per-acre land bid easily surpasses Alberta.●

continued from page 4

ACMP

al requirements and is likely to satisfy the applicable program approval standards of the federal Coastal Zone Management Act.

With the preliminary approval the federal agency will initiate the process to comply with the National Environmental Policy Act, and DNR said in a statement that the EIS process is expected to be completed, and final approval of the ACMP amendments issued, by Dec. 31.

NOAA has scheduled scoping meetings in Barrow, Anchorage and Juneau July 25, July 27 and July 28; the agency said written comments on the intent to prepare an EIS will be accepted through Aug. 5.

NOAA said the state of Alaska made "substantial revisions" to its Coastal Management Program in 2004. Federal law requires amendments to approved state coastal zone management programs to be submitted to the Office of Coastal Resource Management "for approval in order to allow continued federal funding for program implementation and application of federal consistency under the new enforceable policies."

The EIS will evaluate alternatives and environmental consequences "for only two actions that are available to OCRM: (1) approve the program amendments as part of the state's federally-approved coastal management program, and (2) do not approve the program amendments, or status quo."

Since the state has already adopted the revised regulations, NOAA said, if the amendments were not approved it "would mean that the new statutes and regulations would not be part of the state's federally-approved coastal management program."

—KRISTEN NELSON

● WASHINGTON, D.C.

OPEC can still influence oil prices

Cartel unable to bring down current prices, but could be in a strong position next year; OPEC president refers to $50 oil as 'normal'

By BRAD FOSS

Associated Press Business Writer

OPEC's inability to bring down the cost of oil has helped push U.S. gasoline prices above $2 a gallon for the past three months. But don't jump to any hasty conclusions about the cartel's influence or intentions in the market.

The Organization of Petroleum Exporting Countries could be in a stronger position next year if analysts' forecasts of a growing supply cushion prove to be correct. And while that would ease traders' jitters and likely make oil and gasoline cheaper, it might also put OPEC in the mood to cut production to prevent prices from falling too far.

OPEC officials, who said the week of June 20 that they are considering boosting their output target by 500,000 barrels a day, insist they aren't to blame for the latest surge in oil prices to the record $60 per barrel level. They say their aim is to ease prices as a way of keeping the global economy from seizing up.

But traders dismissed the latest effort — as well the OPEC agreement on June 15 to raise its output target by half a million barrels on July 1 — because no new barrels would immediately hit the market and because it would further deplete OPEC's already thin supply cushion.

Record close on Nymex

On June 24, after climbing as high as $60 a barrel for the second straight day, light, sweet crude for August settled at $59.84, an increase of 42 cents on the New York Mercantile Exchange. It was a record close on Nymex, where oil futures have been traded since 1983.

On London's International Petroleum Exchange, Brent crude futures for August delivery rose 40 cents to settle at $58.40 a barrel.

"It's clear that OPEC has lost control of prices in the near term," said Yasser Elguindi, senior managing director at Medley Global Advisors in New York.

OPEC officials pin the blame for soaring prices on the world's limited refining capacity and speculative trading on futures markets. But that's not to say they're unhappy — despite public pronouncements to the contrary — about the huge profits the cartel is reaping.

Analysts said there are a wide range of factors contributing to the 60 percent surge in oil prices in the last year that are beyond OPEC's control.

Economists didn't see demand surge coming

For starters, economists worldwide failed to predict last year's 3 percent surge in global oil demand, with half of that growth coming from China. As a result, everyone from Saudi Arabia to Exxon Mobil Corp. was caught off guard. This was compounded, analysts said, by years of underinvestment in new production and refining capacity.

Even now, flush with cash as a result of high prices, major oil companies are using large sums to buy back shares and raise dividends. This is partly out of fear that the higher prices won't last, but also reflects the opportunity constraints the industry faces as oil-rich nations such as Venezuela and Russia make it ever more expensive for foreign companies to gain access to their natural resources. Supply disruptions following the war in Iraq, Hurricane Ivan and labor strife in Venezuela have also taken a toll on market stability. So has the tapering off of Russian production.

"It's a bit naive to think that it's up to OPEC to open the taps and flood the market," said Antoine Halff, director of global energy at Eurasia Group in New York.

And yet, with crude inventories steadily rising around the globe, the roughly 30 million barrels per day that OPEC has been pumping cannot be ignored. "Stocks have been rebuilt by quite a bit," said Halff.

U.S. crude supplies up

In the United States, crude supplies stand at 327.4 million barrels, or 8 percent above year ago levels, according to the Energy Department, which said this week that "inventories remain well above the upper end of the average range for this time of year."

Whether the economic and political uncertainty around the globe justifies the level of fear gripping energy markets or not, analysts said the underlying factor — the extremely thin supply cushion — could begin to dissipate in 2006. New oil development projects in Saudi Arabia and in some non-OPEC countries will soon come on line, and demand growth is slowing in China and the United States, they said.

PFC Energy, a Washington-based consultancy, estimates that OPEC's spare production capacity, which is currently about 1.5 million barrels per day, is on pace to rise as high as 2.7 million barrels per day a year from now. Moreover, most of the extra barrels coming from Saudi Arabia, Kuwait and Nigeria will be the light-sweet crudes that refiners prefer for the production of transportation fuels. While not as large as the 3 million to 5 million barrel per day supply cushion that the markets were accustomed to in the 1990s, this could be enough excess production capacity to ease traders' jitters and allow prices to begin falling.

OPEC may defend prices

It is at that point, PFC and others warn, that OPEC may step into its lost-but-not-forgotten role of reining in output to defend prices.

"What we don't know is what level they want prices to stay at," Elguindi said, though he emphasized that the days of $25 a barrel as a suitable level are long gone.

Energy consultant Dan Lippe of Houston-based Petral Worldwide said "we could be back in the mid-$30 range by the beginning of next year unless the Saudis step in." But PFC Energy contends the Saudis would step in much sooner, if needed, to keep prices above $45 a barrel "to satisfy the OPEC price hawks and to preserve income."

In a June 26 Reuters report out of Kuwait City, the president of OPEC referred to a Brent crude price of $50-51 per barrel as "normal," resulting in some consensus among observers that OPEC's latest target price is $50 per barrel.

Even if predictions of a larger supply cushion in 2006 come true, analysts cautioned that the market is likely to remain tight and that prices will be volatile, assuming strong demand and continued geopolitical uncertainty. In other words, OPEC's influence on prices will ebb and flow, as always, depending on a variety of external factors.

"The thing is, we shouldn't just sit back and expect OPEC to do everything," said oil analyst Timothy Evans at IFR Energy Services in New York.

"Consumers can make more intelligent choices, particularly about the mileage of the vehicles they drive," he said. "Factors like these are clearly outside of OPEC's sphere of responsibility." ●

Editor's note: In a number of press reports, including a June 26 Reuters story out of Kuwait City, the president of OPEC referred to a Brent crude price of $50-51 as "normal," resulting in some consensus among observers that OPEC's latest target price is $50 per barrel.

ALABAMA

Plan to drill offshore Alabama withdrawn

A Colorado-based oil company has shelved plans to drill an exploratory gas well among the seagrass beds in Grand Bay offshore Alabama.

Duncan Oil Inc.'s drilling application called for moving barges and supply boats through an area federal scientists call "one of the most biologically productive" estuaries on the Gulf of Mexico.

The Mississippi side of the bay is protected as part of the Grand Bay National Estuarine Research Reserve, but the Alabama side does not have those federal protections. Duncan's application was withdrawn after the company's environmental consultant found seagrass beds growing throughout the proposed access route and within the working area around the proposed drilling rig, the Mobile Register reported in a story June 25.

—THE ASSOCIATED PRESS

● APPALACHIA

Geologists search Appalachians for oil

Department of Energy, states, energy companies to study foothills area, centered in Ohio, looking for deeper deposits

THE ASSOCIATED PRESS

A consortium of the U.S. Department of Energy, several states, 17 energy companies and an industry group plans an exhaustive study in search of new oil reserves beneath the Appalachian foothills.

The two-year review is being sparked by record-high prices for crude oil and the country's continuing need for it.

Standing in the way of the revival of the Appalachian basin as a top oil-producing region are the same factors that sent speculators elsewhere after the area's heyday: the expense of and technical obstacles to finding the reservoirs, digging deep enough to strike and moving the oil where it needs to go.

Appalachian oil made the Rockefeller family fabulously wealthy when some of the world's first wells were dug in 1859, and the region remained a significant producer through the early 1900s.

A 260-mile stretch centered on northwest Ohio saw nearly 100,000 wells that produced about 600 million barrels. But eventually coal trumped crude as the area's most valuable and accessible natural resource.

Now scientists are poring through existing records to make educated guesses as to the existence and location of bigger, deeper oil deposits. Geological similarities between the basin and the oil fields of west Texas have them excited about the possibilities.

"It won't replace Saudi Arabia, but it could be important," said Brandon Nuttall, a petroleum geologist from Kentucky who is part of the project.

Earlier wells shallow

Earlier wells typically were dug to a depth of about 1,400 feet. If jackpot reservoirs at extreme depths — elephants, in industry slang — exist in the basin, researchers estimate they could lie as far down as 20,000 feet.

"A way to think of the basin is as a closed, big Webster's Dictionary. In the past, we drilled down to about the letter 'D,'" said Kathy Flaherty, a petroleum geologist with Abarta Oil & Gas Co. in Pittsburgh.

"Now, just think of what is past the letter 'D' in your dictionary. Geologists are starting to imagine that. If we put a hole deep enough down, who knows what we will find."

A 20,000-foot well would cost at least $6.82 million to dig and maintain, according to the Energy Department.

"If you don't know you're going to find anything, it is hard to get somebody to give you that kind of money," said James Drahovzal, an earth scientist with the Kentucky Geological Survey.

But with crude oil selling at $60 a barrel and gas going for $2 a gallon, industry officials are hoping they'll find something worth bringing up.

"There's all that sedimentary rock out there we've not explored. There could be a world-class field out there," Drahovzal said.

"But we're not sure. All we can say is there might be. Conditions appear favorable." ●

ALASKA

Agrium task force meeting delayed

The Governor's Agrium Task Force cancelled its June 29 meeting, which will delay delivery of the final task force recommendations to Alaska Gov. Frank Murkowski for a week or two.

Conflicts with schedules of task force members will shift the meeting to mid-summer, according to Bill Popp, task force co-chair.

Popp said he and co-chair Bob Favretto are aiming for a high level of participation at the upcoming meeting because the panel will be approving and issuing its final recommendations.

—STEVE SUTHERLIN

PERTH, AUSTRALIA

Alcan terminates 20-year gas sales deal

Canadian aluminum company Alcan Inc. on June 27 canceled a 20-year gas sales deal with Australia's Woodside Petroleum due to gas price hikes.

Alcan signed the agreement last November to buy gas from Woodside's part-owned Blacktip gas field in the Joseph Bonaparte Gulf off Australia's northwestern coast. Woodside owns 53.85 percent of Blacktip. ENI Australia, a unit of Italy's ENI SpA, owns the rest.

Under the deal, Woodside and ENI Australia agreed to supply 44 petajoules (about 850 million tons) of natural gas each year for up to 20 years.

Under the deal, Woodside and ENI Australia agreed to supply 44 petajoules (about 850 million tons) of natural gas each year for up to 20 years.

In a statement released June 27, Alcan said it was pulling out of the deal because of Blacktip's request for a "substantial price increase" on the gas, which was to be delivered to the company's Gove alumina refinery in the Northern Territory.

"We are extremely disappointed by the actions of Blacktip as we are aware of the impact of this change on a number of stakeholders," said Richard Yank, president of Alcan's Pacific alumina and bauxite operations, adding that the proposed price hike was "unacceptable."

The amount of the price hike was not immediately released.

The cancelled agreement also included a 620-mile pipeline across Australia's Northern Territory to transport the gas to Alcan's refinery on Gove Peninsula. Alcan said it was "reviewing the implications of this situation" on the proposed pipeline development.

—THE ASSOCIATED PRESS

NETHERLANDS

Conoco looks at Dutch LNG terminal

Integrated oil and gas company ConocoPhillips Co. said June 24 that it has agreed with Essent Energie BV to jointly study the feasibility of developing a liquefied natural gas import terminal in the Netherlands.

The companies have targeted a 100-acre possible site for the project at the Port of Eemshaven and have arranged a land-option agreement with owner Groningen Seaports. ConocoPhillips and Essent, the Netherlands' largest energy company, plan to finish the initial study near the end of the year and then make a decision on how to proceed into the next phase.

A final investment decision may come as soon as 2007, and a terminal could be in operation by 2010, according to ConocoPhillips.

—THE ASSOCIATED PRESS

● ALBERTA

Fear and loathing vs. self-assurance

Albertans in two camps as energy regulator sets benchmarks for sour gas development near high-density populations, approving four of six wells requested by Compton Petroleum

By GARY PARK
Petroleum News Canadian Correspondent

It has been billed as the ultimate showdown in Alberta between economic gain and public safety, with the well-being of 250,000 residents and the development of 40 percent of the province's remaining natural gas reserves at stake.

Not surprisingly, it turned into the longest well license hearing in Alberta history and ended June 22 with a ruling by the Alberta Energy and Utilities Board that had something for everyone, without any clear-cut winner emerging.

Since late 2001, Calgary-based Compton Petroleum has been locking horns with communities, environmentalists and health groups in battling for permission to drill six sour gas wells just outside Calgary's southern limits to tap a reservoir of about 68 billion cubic feet.

At issue is a hydrogen sulfide content of 35.6 percent and the danger that would pose to 250,000 residents — one-quarter of Calgary's population — if ever there was a blowout or a leak.

The board estimates there are already 6,000 "significant" sour gas wells close to human settlements in Alberta, including 105 around the Calgary city limits.

Sour gas has killed 36

Sour gas pumps C$1.5 billion a year into government coffers and accounts for 37,000 jobs and C$1.3 billion in annual wages.

But the dangers are equally well documented, with 36 industry workers killed by sour gas exposure in Alberta over the last 30 years, two of them in a celebrated 1982 blow-out that lasted 68 days, forced an evacuation of nearby communities and spread the distinctive rotten-egg smell of hydrogen sulfide over a wide swath of the province.

The conflicting opinions over the risks of sour gas production got a thorough airing during a 30-day EUB hearing earlier this year and culminated June 22 when the regulator approved four of Compton's planned six wells.

But the board took the unusual step of withholding drilling permits until Compton met 15 conditions, dominated by the need for an improved emergency response plan.

It gave Compton until Aug. 15 to say whether it would proceed with the project and until Nov. 1 to file a revised response plan. If licenses are issued they will remain valid only until Jan. 1, 2008.

While Compton said it needed more time to study the ruling before commenting, some analysts believe the costs of complying with the ruling might outweigh the economic benefits.

If that happens it will likely drive away other companies reportedly eager to drill close to Calgary, depending on the outcome of the Compton application.

Government says board set high standards

The Alberta government's stance is unqualified.

Energy Minister Greg Melchin said that although the threat to life can't be overlooked, the EUB has set high standards in regulating sour gas production and the industry has complied with those rules to ensure Albertans are safe.

He said there is a "far greater hazard with driving our cars … than there is with sour gas."

Melchin said the EUB verdict was an "important signal" that sour gas can be safely developed.

Premier Ralph Klein urged Calgary-area residents to follow the government's lead and put their faith in the EUB, which he said has done a good job of "enforcing safety standards."

David Pryce, a vice president of the Canadian Association of Petroleum Producers, said the industry has maintained for "quite a while" that it has developed the expertise to safely drill for and develop sour gas.

But David Swann, a former medical officer and health and environment spokesman for the opposition Liberal party in the Alberta legislature, said that allowing four wells with "critical levels" of hydrogen sulfide in "such close proximity to hundreds of thousands of southeast Calgary residents poses an unacceptable hazard."

"We cannot be certain evacuations will run smoothly and safely when mere minutes can mean the difference between life and death."

Ric McIver and Diane Colley-Urquhart, two members of Calgary city council, suggested that the only good EUB decision would have been a rejection of Compton's plan.

Board says wells a potential hazard, but have low risk

The EUB itself conceded that given the hydrogen sulfide content of the Compton wells, they present a "potential hazard during drilling, completion and production operations (expected to stretch over 15 years), but a low level of risk."

However, the EUB gave an assurance that it had applied "extra caution" in weighing the Compton proposal, including rejecting Compton's initial emergency response plan as inadequate.

It imposed an emergency awareness zone covering a 15-kilometer radius from the Compton wells — almost double the 8-kilometer zone suggested by Compton — while reducing the size of the area that would have to be evacuated in the event of a leak from 15 kilometers to 5 kilometers, plus a sheltering zone of 4.7 kilometers where residents would be notified to remain in their homes until the sour gas had passed.

In 2002, the EUB imposed tighter controls on oil and gas producers who encounter even small quantities of hydrogen sulfide.

The regulator took two years to approve plans by Compton to drill a well and associated facilities in southern Alberta.

That well was designed to produce only 2 million cubic feet per day of natural gas, of which 0.4 to 0.64 percent was expected to be hydrogen sulfide.

To overcome strong resistance from farm families in the area, Compton was forced to accept an alternative well site and take elaborate precautions during drilling and production.

The EUB said then it was taking the measures to create and sustain "public credibility and confidence." ●

JUNEAU, ALASKA

Kensington mine gets final permit

Alaska Gov. Frank Murkowski said June 29 that he had received a phone call from the U.S. Environmental Protection Agency, telling him that EPA was issuing the final permit needed for Coeur Alaska's Kensington Gold Project north of Juneau.

"As I understand it, construction will start in July," Murkowski told a press conference.

Murkowski said the ability of Coeur to get a green light from all federal and state agencies sent a "signal we can develop mines in Alaska," noting that permitting work for the mine began 18 years ago. Since 1987, Coeur "has performed over 900 environmental studies at a cost of over $25 million," the governor's office said in a press release.

The governor commended two state Department of Natural Resources employees — Bill Jeffress, director of the Office of Project Management and Permitting, and Bob Loeffler, director of the Division of Mining, Land and Water — for their efforts on getting the mine permitted.

Construction of the mine and ancillary facilities is expected to provide 300 jobs during construction and 200 direct and 180 indirect jobs when the mine is in operation.

"Alaska is moving forward — and it is because of private companies willing to invest in Alaska, a state permit climate that is finally streamlined and efficient, and the cooperation of our state and federal permitting agencies," Murkowski said.

● ANCHORAGE

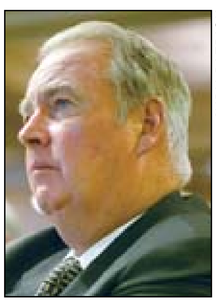
Stranded gas contract by end of the year

Measure to go to Alaska Legislature before end of year, Gov. Murkowski, producers tell AOGA-Chamber luncheon

By KRISTEN NELSON
Petroleum News Editor-in-Chief

Alaska Gov. Frank Murkowski told the annual AOGA-Anchorage Chamber luncheon June 27 that a major new player will be coming into Alaska. But he wouldn't say who (see Insider).

"I can tell you that there's going to be a major announcement here very soon on a major player," he said. "Not that we don't have major players now," he added, "but it will get a little crowded."



JUDY PATRICK

"… we've been able to accomplish more in the last 24 months than we've been able to accomplish in the last 24 years" on developing North Slope natural gas. —Alaska Gov. Frank Murkowski

Murkowski provided no details: "when they're ready to announce it, you'll find out."

The governor reviewed progress on a gas line, contrasting what's happening today with efforts in the past: "The difficulty was always the cost of moving that gas" combined with prices of less than $3 per thousand cubic feet. "Well that's changed dramatically now, so we've been able to accomplish more in the last 24 months than we've been able to accomplish in the last 24 years" on developing North Slope natural gas, Murkowski said.

He said the state is looking at three proposals — from the producers, from TransCanada and from the port authority — and related that he's been asked why it's taking so long; isn't it simple?

JUDY PATRICK

Combined, there are "huge permitting issues, huge fiscal issues in the next two years" and the companies represented by AOGA "are all making decisions themselves about whether or not to invest in Alaska." —Judy Brady, executive director, Alaska Oil and Gas Association

It's not, he said: "The details associated with the limited liability corporation (the structure for the state's equity participation), the contract language, the derivatives, the work commitments, the definition of tariffs, the role of FERC …" involve fiscal and financial terms, rights of way and interaction between the companies and the state.

The governor said the administration's hope is to have a contract negotiated and out for public process so that it can go to the Legislature prior to Thanksgiving.

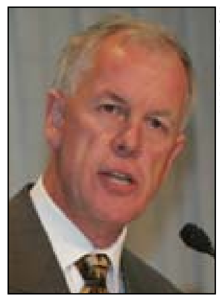
AOGA: Decisions coming

AOGA Executive Director Judy Brady said decisions over the next two years "are going to change this state."

Some decisions will be made by the public, some by those interested in public service, she said: the governor's seat is on the ballot in 2006, along with the entire Alaska House of Representatives. Elections for borough mayors in both Kenai and the North Slope Borough are coming up.

There is the gas contract and an initiative to do away with the economic limit factor, "which would add about $3 billion to the cost in the state." An initiative for a gas reserves tax would add $700 million a year in costs.

Both the North Slope and the Kenai Peninsula boroughs are developing new coastal zone enforceable policies — as are other districts — "but those two districts make a great deal of difference to us in whether or not we can operate…"



JUDY PATRICK

There is work to be done on the base business on the North Slope, Prudhoe Bay and Kuparuk: more accumulations, satellite fields, "still tens of billions of dollars of in-field drilling and tertiary recoveries and waterfloods to keep that business going." —Steve Marshall, president, BP Exploration (Alaska)

Combined, Brady said, there are "huge permitting issues, huge fiscal issues in the next two years" and the companies represented by AOGA "are all making decisions themselves about whether or not to invest in Alaska."

BP: world-scale opportunities

Steve Marshall, president of BP Exploration (Alaska) said BP sees "Alaska as having world-scale opportunities: tens of trillions of cubic feet of natural gas; still billions of barrels of conventional oil … albeit in smaller accumulations" and "billions of barrels of viscous oil, heavy oil."

North Slope gas is "a vital project to BP," Marshall said. "It's a huge undertaking. It's important to get it right." BP is committed, he said, to getting everything done on the contract so that the governor can take it to the Legislature in the fourth quarter.

Other opportunities include viscous oil, and the 20 billion barrels plus of very heavy oil, "oil in place that rivals Prudhoe Bay in size." The Canadians, he said, are starting to achieve 50 percent recoveries "and if we can do that, with that resource, that's twice the USGS estimate for what ANWR could hold." The oil is known, "we drill through it every day." The issues are technical: would steam recovery work on the North Slope, through permafrost?

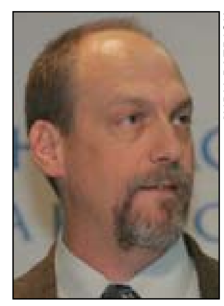
There is work to be done on the base business on the North Slope, Prudhoe Bay and Kuparuk, Marshall said: more accumulations, satellite fields, "still tens of billions of dollars of in-field drilling and tertiary recoveries and waterfloods to keep that business going." The investment in wellwork alone will be more than $100 million at Prudhoe this year, "a 20 percent increase from last year and more to do there," he said.

To have the confidence to continue to invest in Alaska, BP asks for "clear, unambiguous rules," he said, "rules that don't change; rules that give us the confidence that we can get an appropriate return."

An appropriate return is one that recognizes risks — technical risks, oil-price risk, gas-price risk and "the price of failures." Industry invested $750 million in heavy oil on the North Slope just to get production started. Badami was a disappointment. Northstar cost three times the initial cost. And exploration programs don't always deliver on their promise: "some of you may even remember the Mukluk well (in the Beaufort Sea), a billion dollars … spent and nothing there." Those are risks industry normally takes, he said: "We need to take those risks; we just want to know what we face in the way of fiscal stability so we can continue making those investments."

Opportunities, challenges in Cook Inlet

John Barnes, Alaska business unit leader for Marathon Oil Co., said Marathon's focus is on natural gas in Cook Inlet. "We're currently the leading explorer and developer of gas reserves in the Cook Inlet," he said, and have had a continuous drilling program for almost five years. Other companies, including smaller independents, have also been drilling for gas in Cook Inlet, and Barnes said the Department of Natural Resources' report on 2004 showed an increase in Cook Inlet reserves, from 2.03 trillion cubic feet in 2003 to 2.087 tcf in 2004, despite annual consumption of some 200 billion cubic feet. And deliverability has stabilized for 2004 and 2005 at about 700 million cubic feet a day.



JUDY PATRICK

"Is it possible, for one straw to really break a camel's back? I don't know, but the regulatory camel is pretty well loaded." —John Barnes, Alaska business unit leader, Marathon Oil

"And it's the result of a lot of hard work and a lot of difficult decisions that were made over the last decade," Barnes said.

Decisions made in the future will impact Cook Inlet, he said. A decision to build a gas pipeline from the North Slope "is clearly a step towards a spur line to the inlet which will create both opportunities as well as challenges." Opportunities include new or renewed investment opportunities, surety of natural gas delivery for utilities, integration with existing infrastructure "and possibly right sizing the gas line." Local producers, he noted, will face the challenge of meeting or beating the price of delivered gas.

Any significant new North Slope development could hurt the inlet if it draws off existing support industry and "results in a net loss of talent" in the inlet, although a stronger business climate in the state could help the inlet.

Barnes said the regulatory and permitting burden is "a very difficult area."

"Is it possible," he asked, "for one straw to really break a camel's back? I don't know, but the regulatory camel is pretty well loaded."

Fiscal regime decisions also impact the inlet, he said. The Department of Energy "has recently reported 6 to 8 tcf of potential reserve base," but developing that reserve base will require "hundreds of millions of dollars" and companies considering those investments will weigh "project risk, subsurface risk, regulatory risk and finally fiscal regime risk." The state, he said, can have the greatest impact on fiscal regime risk.

Shell: additional investments planned

Gregg Nady, Shell's Alaska land representative, said it was "gratifying to have Shell so warmly welcomed back to Alaska." The company, he said, operated almost continuously in Alaska beginning almost 50 years ago until 1998, and was "one of the most prominent explorers in

see CONTRACT page 10

continued from page 9

CONTRACT

frontier basins" and an operator and major producer in Cook Inlet.

Shell believes Alaska "holds significant remaining exploration potential," Nady said. The company took a hard look at geologic, technical, commercial, social and political developments in Alaska before it returned. "And we have considerable Arctic operations experience both onshore and offshore in Alaska, Canada, Norway, and particularly in Russia where we operate the Sakhalin 2 project."

JUDY PATRICK

Shell hopes "to commercialize stranded discoveries and make new discoveries" in the Beaufort. … the company plans "to make additional investments in Alaska in both existing basins and new basins." —Gregg Nady, Shell Alaska land representative

Shell "had to solve many complex social, environmental challenges" on the Sakhalin project, and has "done so openly with the involvement of key local and international stakeholders. It is this level of ambition, technology, expertise and commitment to working with stakeholders that we hope to bring to Alaska," Nady said.

Shell believes Alaska has "significant untapped potential," and is "aware of the complex issues in Alaska. But in today's world there are no easy projects, and bringing material oil and gas to market increasingly involves controlling complex problems in technical, commercial, political and social challenges."

Shell took a big position in the Beaufort in March, winning 86 tracts in the Minerals Management Service Beaufort Sea oil and gas lease sale and spending $44.4 million.

Nady said Shell hopes "to commercialize stranded discoveries and make new discoveries" in the Beaufort. He said the company plans "to make additional investments in Alaska in both existing basins and new basins."

He said Shell will work in partnership with key stakeholders in Alaska, and in return needs "a stable fiscal regime, regulatory certainty and predictable permitting, access to acreage including timely lease sales in offshore areas." Key decisions Shell makes in the next few years "will hinge on these factors," Nady said, including "the ability to move forward with operations in the Beaufort Sea in a timely and responsible manner and the ability to participate in new sales that offer material new opportunities."

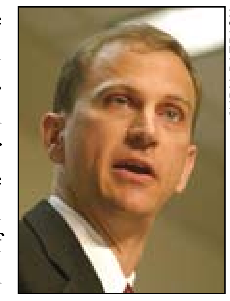
The Minerals Management Service's 2007-2012 five-year OCS "will be an important factor in the future of Alaska," he said.

Pioneer: 'formidable' challenges

Ken Sheffield, president of Pioneer Natural Resources Alaska, said independent companies coming into Alaska face "formidable" challenges. Fields that are found now "are nothing like the billion-barrel fields that opened the slope." Industry is working now "to commercialize smaller, lower-quality oil reservoirs, viscous oil, natural gas, which will not have a market until the next decade, and remote resources in NPR-A and offshore," he said.

The North Slope is one of the highest cost areas in the world and projects there have long cycle times, five to 10 years from buying a lease to production, "depending upon drilling success and distance to existing infrastructure," Sheffield said.

But "maybe the largest challenge" companies face on the North Slope is "fiscal uncertainty. Given its heavy dependence on the oil industry for revenue, can the state offer a stable fiscal policy over the life of our large, long-term investments?" he asked.



JUDY PATRICK

"Given its heavy dependence on the oil industry for revenue, can the state offer a stable fiscal policy over the life of our large, long-term investments?" —Ken Sheffield, president, Pioneer Natural Resources Alaska

And in spite of improvements there is still regulatory uncertainty and "permitting remains complex and time consuming."

Price uncertainty is a factor. Because of the long cycle times of Alaska projects, Sheffield said, "we must make our business decisions against a long-term view of prices." Even though the current price of oil exceeds $50 a barrel, "the 10-year average price for North Slope prices is about $23 per barrel. For Pioneer's Alaska projects the price of oil in 2005 is irrelevant. What's important is what the price is in the next decade and beyond."

Then there is exploration uncertainty: will the value of the fields that are found "offset the cost of dry holes, land, seismic" and development costs?

Pioneer is looking at participating "in a number of exploration wells next winter season" and within the next 12 months will make a decision on whether to go ahead with development at its Oooguruk discovery. That project would cost hundreds of millions of dollars and decisions by the Department of Natural Resources and the Department of Revenue, as well as regulatory agencies and contractors, will be required before the project moves ahead. "Pioneer must then weigh the cumulative costs and risks associated with this project and decide to move forward with this development or not."

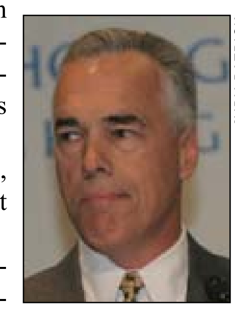
With oil prices high there has been a lot of discussion about raising taxes on the industry. "For new entrants like Pioneer, the threat of uncertain fiscal environment, coupled with the many existing challenges in Alaska, makes our future tough decisions even tougher."

ConocoPhillips: Scales tipped for North Slope gas

Jim Bowles, president of ConocoPhillips Alaska, brought a large scale to the podium and used weights to illustrate his talk. "Since the discovery of the giant Prudhoe Bay field in 1968, a vision has existed to develop this huge gas resource base on the North Slope. But the scales have been tipped against this project," largely due to high costs, regulatory markets and gas prices, which were often less than $2 an mcf.

"However, within the last three years we're really started to see the shift in balance to develop the North Slope gas reserves."

He reminded the audience of the feasibility study completed by ConocoPhillips, BP and Exxon in 2002, reauthorization of the Alaska Stranded Gas Development Act in 2003, federal enabling legislation in 2004, the producers' submittal of a fiscal contract to the state in 2004 and the governor's active participation in negotiations this year.



JUDY PATRICK

"The vision of developing North Slope gas reserves is closer than it's ever been" and "ConocoPhillips is committed to providing its full weight and strength behind this project to make it a successful project." —Jim Bowles, president, ConocoPhillips Alaska

But, he said, threats to the project exist.

"The key to moving a $20 billion project like this forward is certainty and fiscal stability," Bowles said. "The threat of additional taxation, whether in the form of a gas reserves tax or increase in production tax, does nothing to advance the project. In fact it creates greater uncertainty…"

The project is world-class in size and complexity, he said. "The risks inherent in such an endeavor make alignment with the state and the producers absolutely critical. The decisions facing the state are possibly some of the most important decisions it's faced since statehood. The negotiations are progressing, but they take time."

The producers' project, he said, "not only captures the maximum revenue from the gas but it also provides huge job opportunities and an increase in business activities across the state, as well as a supply of clean fuel to Alaskans."

Bowles said "the vision of developing North Slope gas reserves is closer than it's ever been" and "ConocoPhillips is committed to providing its full weight and strength behind this project to make it a successful project." ●

WASHINGTON, D.C.

House passes oil spill prevention measure

The House of Representatives on June 27 unanimously passed a bill aimed at preventing oil spills in the nation's waterways.

Rep. Frank LoBiondo, R-N.J., wrote the "Delaware River Protection Act" following a November 2004 accident involving a Greek oil tanker that spilled 265,000 gallons into the Delaware River. The spill hampered shipping and polluted more than 100 miles of shoreline in Pennsylvania, New Jersey and Delaware — from the Tacony-Palmyra Bridge in northeast Philadelphia to south of the Smyrna River in Delaware.

The measure now goes to the Senate.

The measure would: increase liability limits on single-hull tankers under the Oil Pollution Act; require ships to report objects that are lost overboard to the Coast Guard for immediate recovery; create a new committee to report to Congress on ways to improve oil spill response and prevention, and establish a pilot project on the Delaware River and bay to test techniques to recover submerged oil.

The spill happened when the hull of the tanker was ripped open by a rusty anchor resting on the river bottom. Authorities have not determined where the anchor came from. "The unanimous support for this legislation shows that it is not only very important to our region, but to the nation as well," said LoBiondo, chairman of the Coast Guard and Maritime Transportation Subcommittee. "This bill will help ensure that the ecologically significant areas in New Jersey, Delaware and Pennsylvania are protected from future oil spills, while allowing the vital commerce of the Delaware River and the nation to continue."

Co-sponsors of the measure were Reps. Jim Saxton, R-N.J., Rob Andrews, D-N.J., Mike Castle, R-Del., and Allyson Schwartz, D-Pa.

—THE ASSOCIATED PRESS

● INTERNATIONAL

Oil shale: Real, or just a mirage?

Various signs hint that shale oil's 'time' may be closer than ever; companies jumping on bandwagon in U.S. and overseas

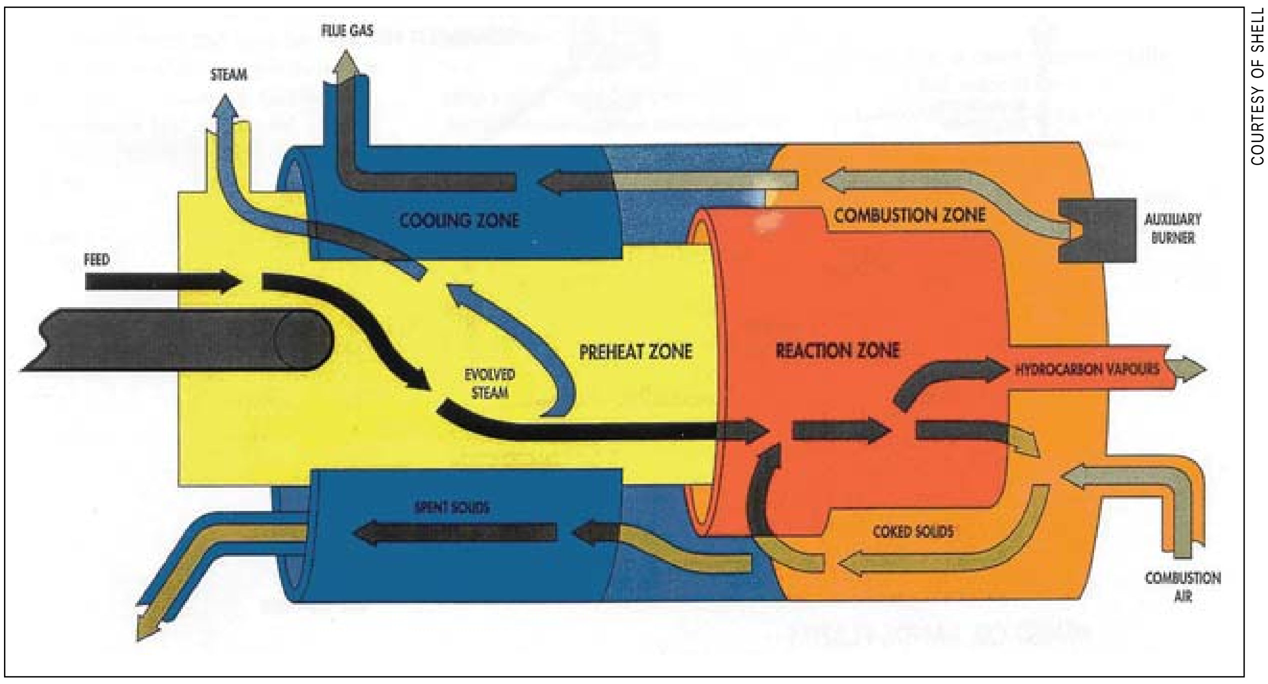
By F. JAY SCHEMPF
Petroleum News Contributing Writer

After decades of unsuccessful attempts to produce oil commercially from more than a trillion barrels entrained in U.S. oil shales, producers — and powerful U.S. lawmakers — are today reviving the prospects of developing this vast resource. The majority of the oil shales lie in Colorado, Utah and Wyoming.

Shell Exploration and Production Co. apparently has come a long way in developing its in situ conversion process, known as ICP, for extracting kerogen, a synthetic light crude oil, as well as gas liquids and other byproducts from the U.S. oil shale deposits (part one of this series in the June 12 issue of Petroleum News described ICP).

1 2 SERIES

Meanwhile, other companies are ready to jump on the oil shale bandwagon, not only in this country but also overseas. Major companies reportedly are perfecting existing and untried underground shale oil retrieval methods, but they're keeping information about these techniques close to their vests.



COURTESY OF SHELL

Designed originally for oil sands bitumen extraction, the Alberta Taciuk Processor, a vertically oriented, multi-chambered thermal system for separating and extracting organics from host solids, can be adapted for shale oil extraction.

Fire flooding

During the short-lived Colorado oil shale boom in the 1970s and 1980s, several companies championed in situ extraction based on a rarely used secondary oil recovery technique called oxygen injection or fire flooding.

In fire flooding, compressed air is forced into a depleted oil reservoir via injection wells. Some of the underground oil is then ignited, and the resultant fire radiates heat into the surrounding formation, thinning and pressurizing the passed-over oil and driving it toward producing wells. Company researchers think that, with some tweaks, this technique will work in oil shale but there's no evidence that this approach has ever been tried.

The closest analogy to fire flooding oil shale may be Project Rulison, a 1969 underground nuclear blast near Rifle in western Colorado. Detonated far underground in tight sandstones, the bomb experiment yielded highly radioactive — and thus useless — natural gas. This experiment was followed in 1973 with a massive, three-bomb attempt in the same general area. That test, too, failed.

But the concept of heating the subsurface to produce oil from shale apparently encouraged Shell to dedicate the research and development resources, and lots of time, that have resulted in the company's ICP process.

Surface retorting

But despite the obvious benefits of and progress made in heating the shale in situ, nobody's dismissing surface retorting technologies. A number of retorting techniques exist, one or two of them even being used in pilot projects around the world. In Brazil, for example, a pilot surface retort called the Petrosix process produced the equivalent of 1.4 million barrels of shale oil and other products during 1999.

Other surface-oriented retort/pyrolysis systems have been demonstrated, both in the United States and abroad; however, none has beaten the mirage of viability that oil price fluctuations bring to commercial shale oil production.

But several American and Canadian companies say updated variations on known mining/retorting techniques allow them to produce the shale oil today at a lower cost than in the past.

Utah process yields $10 oil, says inventor

One of the companies, Oil-Tech Inc. based in Vernal Utah, says its demonstration surface retort in Uintah County, near Bonanza, produces kerogen at a cost of $20 per barrel when fed with shale purchased from outside sources. If the company had its own mine as a source of feedstock Oil-Tech says the cost would fall to $10 per barrel or less.

Oil-Tech's prototype retort — an 80-foot vertical stack of five hollow modules capable of processing up to 1,000 barrels per day — uses electricity to heat incoming shale to 1,000 degrees Fahrenheit. Gravity flow, cooling and filtering of the condensed vapor ultimately yields shale oil ready for refining. The retort is designed for zero toxic output, say company officials — the pressure inside the sealed modules is lower than that of the atmosphere, thus eliminating vapor emissions.

According to Oil-Tech, an independent engineering firm tested the process's validity during a March 2004 demonstration run, using about 1,000 tons of crushed shale.

The company says production costs can be lowered even more by reusing processed shale to heat incoming new feedstock, a feature that other retorting systems incorporate into their processes. In Oil-Tech's case, the spent rock can be infused with oxygen to raise its temperature to as much as 2,500 degrees. Then, instead of using electricity, the super-hot residue can be re-employed to heat incoming shale.

Once the oil is removed, the residue — a light, ash-like substance — can be mixed with topsoil for projects such as re-vegetation, the company says.

Noting that larger companies have spent up to $400 million on retorts, Oil-Tech says it can produce multiples of its 1,000-barrel per day unit for around $2 million apiece. Meantime the prototype retort operates from time to time, as the owners try to interest government and private industry in commercial operation.

This summer, the Bureau of Land Management plans to sell as much as 60,000 tons of mined shale that was abandoned years ago. Oil-Tech hopes to buy a portion of this shale to demonstrate that at today's high oil prices the system can vault over the cost barriers to achieve commercial shale oil production.

ATP, the multi-tasking separator

In the mid-1970s, at about the same time as companies were trying to make western U.S. shale oil profitable, Bill Taciuk, a scientist with the Alberta Energy Research Institute, invented a surface-based horizontal, multi-chambered thermal desorption and hydrocarbon cracking system for separating and extracting organics from host solids. The institute called the invention the Alberta Taciuk Process, or ATP for short.

Taciuk targeted ATP primarily at separating bitumen from oil sands, but noted that the process could also be applied to shale oil production. In 1975 the institute licensed the technology to UMA Engineering, a Canadian industrial process developer. But before the company could market the process for possible use in the United States the

see OIL SHALE page 12

ALBERTA

‘Be bold, aim high’ — Dinning’s vision

Frontrunner to succeed Klein as Alberta premier wants to stop shipping province’s unprocessed resources to U.S., China

By GARY PARK
Petroleum News Canadian Correspondent

Beyond pledging that he will not seek re-election, Ralph Klein won’t put a firm date on his departure from politics, although the betting is later this year.

That hasn’t prevented Jim Dinning from building what many view as an insurmountable lead in the unofficial race to succeed Klein as Alberta’s premier.

JIM DINNING

It has been a carefully crafted process of image-building and grooming for the top post.

For 11 years he was a provincial cabinet minister, half of that time as Klein’s finance minister charged with overhauling the Alberta economy.

Since 1997, Dinning, 53, has been in the private sector, as a vice president of TransAlta and lately as chairman of the Western Financial Group.

He has taken great care to keep his overt political ambitions under wraps and avoid any suggestion that he is criticizing the government or Klein.

Alberta’s energy future

But that ended June 22 when Dinning laid out his vision for Alberta’s energy future.

“We need to be bold. We need to aim high,” he told the American Association of Petroleum Geologists conference in Calgary.

RALPH KLEIN

Dinning said Alberta’s vast natural resources storehouse provides a unique opportunity to upgrade and refine the assets in the province rather than just shipping raw materials to the United States and China.

He said Alberta has only started to “tap into the potential of what could be done right here in Alberta.

“Alberta should be the leading center of innovation and active innovation in this part of the energy industry and if we are going to get the maximum value out of all the carbon we have in Canada we have to think in terms of a fully integrated energy system,” he said.

Dinning said Alberta is the “sweet spot” where geology and geography come together in a world-class opportunity to develop conventional oil, natural gas, heavy oil, synthetic crude, bitumen, coal, coalbed methane and petrochemical feedstock.

He endorsed a “hybrid of public policy tools” such as royalty relief, tax credits, capital cost allowance and technology grants to promote resource extraction.

However, he was emphatic that the Alberta government should stop short of taking an equity position in any major projects, although he endorsed hiking government’s annual allocation to the Alberta Energy Research Institute to C$40 million from C$15 million-$18 million.

Alternatives needed for upgrading bitumen

Dinning paid special attention to the need for finding alternatives to natural gas in upgrading raw bitumen from the oil sands and the future of clean coal in Alberta.

“Injecting natural gas into oil sands to produce oil is like turning gold into lead,” he said, arguing that coal, coke and bitumen could all lower the reliance on gas.

He referred to industry efforts to reduce gas consumption such as the Nexen-OPTI Canada partnership that will gasify all bitumen produced at the 70,000 barrel-per-day Long Lake project; Petrobank Energy and Resources’ Whitesands project to rely on in-situ combustion to heat the reservoir and melt the bitumen; and Suncor Energy’s plans to produce synthetic gas and help power the overall operation.

“These are remarkable accomplishments and what makes them even more significant is that they aren’t radical solutions,” Dinning said. “It’s simply taking … existing technologies and putting them together in a brand new way.”

An active crusader in downplaying coal’s historical stigma as a dirty fuel, he praised efforts to remove pollutants such as sulfur and nitrogen during the burning process.

“Coal is predictably inexpensive,” while gas is volatile and currently high-priced, he said.

“Coal burning as clean as natural gas is a great aspiration,” Dinning said. ●

---

continued from page 11

OIL SHALE

shale boom lost a zero. Today, UMA markets the process for oil sands, toxic waste remediation and other thermal processes.

However, when applied to oil shale ATP is said to increase kerogen oil and combustible gas yields from the shale; improve thermal efficiency; and reduce process water requirements. Apparently the process also minimizes residual coke remaining on spent shale, thus rendering the residue better for environmentally safe disposal. The process also uses some of the hot processed shale to re-circulate into the retort section for heat transfer.

Aussie project gets first ATP shale application

In recent years, an Australian group led by Southern Pacific Petroleum has used a demonstration-scale, 4,500-barrels per day ATP retort for shale oil extraction, planning to eventually build larger models that can produce as much as 200,000 barrels per day of shale oil.

The group began mining shale from its Stuart deposit near Gladstone on Queensland’s central coast. The deposit reportedly contains some 2.6 billion barrels of recoverable shale oil. In 2000 Canadian oil sands company Suncor Energy bought into the project and financed construction of the demonstration plant in Gladstone. In April 2001, however, Suncor bowed out of the project, citing total commitment to its oil sands business.

A month later, despite a spate of mechanical problems and merciless harrying by Greenpeace, the group sold more than 40,000 barrels of medium shale oil to Southeast Asian refiners. Thereafter, operations limped along until December 2003, when Southern Pacific Petroleum ran into financial difficulties.

The plant remains closed today but the project could restart with new financing and management led by the owners of the New York-based Ziff-Davis publishing empire and a mysterious Texas oilman, Jeff Sandefer. But until new arrangements are made, the jury is still out on the Stuart shale deal, although different companies are mulling possible projects in other shale-rich areas in Australia.

‘Sniffing’ Canadian shale for aromatics

In Canada, major oil sands developer CanWest Petroleum Corp., based in Vancouver, B.C., is dedicated to processing the country’s not insignificant western oil shale resources. The company currently is evaluating several retorting processes, including ATP. But the company’s emphasis would be on the Canadian shale’s extremely high aromatics content, rather than its light oil.

The company operates the Pasquia Hills Oil Shale Prospect, comprising 1 million acres under permit in central Saskatchewan. A 50,000-acre mine site overlies what the company says are 4.3 billion barrels of shale hydrocarbons, more than half of which are aromatics. The company believes it could extract the aromatics for petrochemical feedstock.

As part of a joint venture with Nova Chemicals Corp., CanWest recently announced that it will conduct further analysis, including liquid characterization tests, on the Pasquia Hills shale oil. In addition, the company is building a laboratory scale, steam-assisted retort that will produce basic data needed for possible development of an “advanced steam-assisted retort.”

The upcoming shale picture

Worldwide, oil shale development continues in various stages of maturity. Perceptions of the technology are changing and industry watchers expect announcements of commercial-scale oil shale extraction technologies sooner rather than later.

Meanwhile, related petroleum industry phenomena can’t be overlooked. The rapidly expanding and highly profitable development of Canada’s Athabasca oil sands, for instance, could serve as a model for initiation and growth of a U.S. oil shale industry. The oil sands industry was considered “a loser” as recently as 1990. But as this industry has matured through the learning process, production efficiency has improved significantly and costs have declined. Certainly, say industry experts, such on-the-job learning also would occur in a fully functioning North American oil shale industry.

see **OIL SHALE** *page 13*

● COOK INLET

Unocal applies for gas storage leases

Project at Pretty Creek would involve first state storage leases; company already storing gas on federal acreage on Kenai Peninsula

By KRISTEN NELSON
Petroleum News Editor-in-Chief

Cook Inlet gas producers have said for some time that the inlet needs gas storage to balance demands for natural gas between summer and winter months. Unocal has storage on the Kenai Peninsula and is now proposing to add storage on the west side.

The Alaska Department of Natural Resources is taking public comment on an application from Unocal for gas storage leases at Pretty Creek on the west side of Cook Inlet. Unocal's gas storage at the Kenai gas field on the Kenai Peninsula is on federal leases.

The Pretty Creek application is the first the state has received for storage leases, and would cover some 2,060 acres within the existing Pretty Creek unit. Pretty Creek is northeast of the Beluga River field.

The company plans to convert the Pretty Creek Unit No. 4 well to gas storage in two gas sand horizons, the Beluga 51-5 and the Sterling 45-0. The company said it might drill or re-drill additional wells to these sands in the future "to increase deliverability from the storage facility."

The company plans to convert the Pretty Creek Unit No. 4 well to gas storage in two gas sand horizons, the Beluga 51-5 and the Sterling 45-0. The company said it might drill or re-drill additional wells to these sands in the future "to increase deliverability from the storage facility."

Unocal said the Sterling 45-0 sand is watered out in the PCU No. 4 well and the Beluga 51-5 sand is nearly depleted. Storage would begin in the Beluga sand and then be expanded later to the Beluga sand. Operations would start with just the PCU No. 4 wells, but Unocal said it may later re-drill the PCU No. 2, or drill a new well, for storage operations.

"The storage gas will be injected during periods of excess supply and produced back during periods of increased demand to help balance gas deliverability requirements," the company said. Excess gas is available in the summer months; winter heating requirements cause a higher demand.

The PCU No. 4 well was drilled and completed in November 2001. Unocal said the Beluga 51-5 sand "is not yet fully depleted" but the company wants to convert the well to gas storage "at

see UNOCAL page 14

continued from page 12

OIL SHALE

And while commercial shale oil production in the United States and Canada is in the offing, countries like Brazil, Estonia and a few others continue to actually produce oil from shale. Russia is puttering around with its massive shale resource as well. Oil shale-rich nations — and DOE says some 27 of them have exploitable resources — are keeping a peeper on possible future activity.

The Peoples' Republic of China has produced shale oil in small quantities since the 1920s and continues to do so with 30-year-old retort technology. Now, thanks to the burgeoning domestic demand for petroleum products, the Chinese are looking for larger-scale retorts and advanced technologies to increase shale oil production while also minimizing environmental effects. Shell last year signed an agreement to help study ways to develop some 17 billion metric tons of recoverable oil from shale deposits in China's northeastern Jilin Province. And while no Shell entity has yet raised the prospect, Shell's ICP technology, among others, might prove applicable in China.

So once again, the spotlight is trained on the awesome potential of shale oil production around the world. Nothing's for sure, but maybe this time the spotlight's beam will focus brightly on the likelihood of commercial shale oil production, rather than on a dim scattering of interesting possibilities. ●

BRAZIL

Brazil's oil production hits new record

Brazilian state-run oil company Petrobras set a new daily domestic oil output record of 1.835 million barrels, the company said June 24.

The record was set June 23 as offshore oil rigs pumping crude oil from the Barracuda and Caratinga fields off Rio de Janeiro state in southeastern Brazil reached full capacity, Petrobras said.

The company said improved productivity from recovery of mature fields in the north and northeast regions and in the southeastern state of Espirito Santo also contributed to the record.

The previous record of 1.819 million barrels was reached May 12. The June 23 record was the 10th daily so far in 2005.

—THE ASSOCIATED PRESS

CANADA

Soggy weather dampens drilling forecast

An early spring thaw followed by flooding and record rainfall in parts of Alberta has lowered the target for Canadian well completions this year.

In an updated forecast, the Canadian Association of Oilwell Drilling Contractors has trimmed its forecast to 24,099 completions — still 9 percent ahead of 2004's record count — from the 24,205 it predicted last fall.

Canada is expected to end 2005 with 780 rigs, an increase of 46 from mid-year.

The association reported that an average 598 rigs of 723 were active in the first quarter, short of its projected 613 of 730 rigs, thus reducing operating days to 45,681 from 47,697.

Rig utilization is expected to average 280 in the second quarter, 483 in the third and 575 in the final three months, yielding an average 484 working rigs from a fleet of 742.

The drilling contractors group bases its forecast on an oil price of US$45 per barrel of West Texas Intermediate and US$6.12 per thousand cubic feet on the New York Mercantile Exchange — both estimates the association says are conservative.

Industry figures show 2,001 wells were completed in May, a gain of 56 percent over a year earlier, pushing the five-month tally to a record 8,889 wells compared with 8,464 in the same period last year.

Alberta logged 6,956 wells, a gain of 6.8 percent from 2004's 6,515; Saskatchewan was unchanged at 1,104; and British Columbia lagged behind at 840, down 32 completions. Northern Canada also dipped to 14 from 17.

—GARY PARK

continued from page 13

UNOCAL

this time in order to avoid production-related problems that often occur at the late stages of reservoir depletion."

The Pretty Creek storage facility would be used for "injection of excess gas owned by Unocal." The company said it is "likely that the physical molecules of gas may be sourced from the Beluga River field or from other West Side properties operated by others." Unocal-owned and operated gas would probably come from the Grayling gas sands on the Steelhead platform in the McArthur River field. Unocal said the Grayling gas from the Steelhead has a composition similar to Beluga River gas, and all expected sources of gas are primarily methane "and are very similar to the original gas in the reservoir (so) no fluid compatibility problems are expected."

Daily maximum injection is expected to be 20 million cubic feet. Unocal said no wells penetrate the Beluga 51-5 and Sterling 45-0 sands within a quarter mile of the PCU No. 4 well.

Comments on consistency with the Alaska Coastal Management Program are due July 25, as are comments regarding whether the proposed lease would be in the best interests of the state.

A proposed consistency determination is expected Aug. 8; a final consistency determination and written finding Aug. 15; and awarding of the lease Sept. 9.●

FAIRBANKS, ALASKA

Oil pipeline's assessed value challenged

Three Alaska municipalities are contesting a state review board's decision that assessed the trans-Alaska oil pipeline value at $3 billion.

The Fairbanks North Star Borough, North Slope Borough and the city of Valdez filed an appeal in Superior Court on June 27.

This is the governments' third attempt to change the value, which, if it stands, means about $1 million in lost property tax revenues for the Fairbanks borough.

"It's a disagreement about statutory interpretation of replacement costs," said Fairbanks borough attorney Rene Broker.

Earlier this year, the state petroleum property assessor dropped the value of the pipeline and its associated properties from $3.017 billion to $3 billion. The three municipalities appealed that decision with the assessor's office and lost. They then went to the State Assessment Review Board to seek a reversal.

The board issued a decision that upheld the state petroleum assessor's ruling.

Part of the assessment was determining how much it would cost to replace the pipeline.

The municipalities based their current appeal on three points that the review board failed to rule on, according to the court documents.

First, they said, the Alaska Department of Revenue wrongly interpreted state law by excluding the cost of construction of a replacement pipeline from the pipeline's replacement cost analysis.

The municipalities also said the revenue department didn't include taxes that would be paid during construction of a replacement pipeline. And the department didn't include the costs of roads and bridges that would have to be built for a replacement pipeline. Excluding some expenses in the replacement cost analysis affected the resulting pipeline assessment, the appeal stated.

The pipeline's value shouldn't be dropping at a time when private citizens' tax assessments on property values have increased, said Fairbanks borough Mayor Jim Whitaker.

"Particularly when oil is selling over $50 to $60 dollars a barrel," he said. "Where is the logic behind that?"

—THE ASSOCIATED PRESS

NORTH AMERICA

U.S. picks up 12 drilling rigs; Canada gains 35 rigs

The number of rotary drilling rigs operating in Canada and the United States stood at a combined 1,625 during the week ending June 24, an increase of 47 rigs from the previous week and an increase of 117 rigs compared to the same period last year, according to rig monitor Baker Hughes.

Canada alone picked up 35 rigs compared to the previous week for a total of 257 rigs. But the total count was down by 77 rigs when compared to the year-ago period.

The U.S. rig count stood at 1,370 at the end of the week ending June 24, up by 12 rigs compared to the previous week and up by 194 rigs versus the same weekly period in 2004. Compared to the previous week only, land rigs jumped by 10 to 1,250, while offshore rigs increased by two to 97. The number of inland water rigs was unchanged at 23.

Of the total number of rigs operating in the United States during the week ending June 24, 1,219 were drilling for natural gas and 149 for oil, while two rigs were being used for miscellaneous purposes. Of the total, 857 were vertical wells, 331 directional wells and 182 horizontal wells.

Among the top U.S. producing states in the week ending June 24, Wyoming gained three rigs for a total of 74, while California also picked up three rigs for a total of 26. Louisiana's rig count was 188, up one rig from the previous week. Meanwhile, Oklahoma lost three rigs for a total of 147 and Colorado lost two rigs for a total of 68. Texas was unchanged with 615 rigs, as well as Alaska with 10 rigs and New Mexico with 77 rigs.

● HOUSTON, TEXAS

Alaska independents rise above peers

As earnings season approaches, oil and gas companies doing business in the northernmost state beat average; outside Alaska only Apache expected to see an increase over second quarter

By RAY TYSON

Petroleum News Houston Correspondent

Profits for seven of the largest U.S-based exploration and production independents that do business in Alaska should handily beat on average other sector-leading companies tracked by Petroleum News, according to Thompson-First Call earnings estimates for the 2005 second quarter ending June 30.

Supported largely by unprecedented strength in oil and gas prices, independents in Petroleum News' 20-company survey, including those that have a presence in Alaska, are expected to report 2005 second-quarter profits on average roughly 4.5 percent above the previous quarter and around 37 percent higher than the same quarter last year.

Analysts' estimates for individual companies can be higher or lower than the consensus and tend to change as the reporting season approaches. Estimates also generally exclude one-time charges against earnings and other special items.

Major U.S.-based exploration and production independents that do business in Alaska are Anadarko Petroleum, Kerr-McGee, Pioneer Natural Resources, Devon Energy, Unocal, XTO Energy and Forest Oil. They maintain positions in either the Cook Inlet or on the North Slope.

Others in the quarterly survey are big independents Apache, Burlington Resources, Chesapeake Energy, Noble Energy and EOG Resources, as well as smaller independents Newfield Exploration, Pogo Producing, Cabot Oil & Gas, St. Mary Land & Exploration, Stone Energy, Spinnaker Exploration, Remington Oil & Gas and Houston Exploration.

Several companies that make up the Alaska group are expected to report lower 2005 second-quarter earnings versus the prior quarter. However, the group on average should out-perform its peers by around 12 percent in the 2005 second quarter, according to analysts' consensus estimates.

Pioneer is expected to turn in a 2005 second-quarter profit of about 68 cents per share compared to 58 cents per share in the previous quarter and 58 cents per share in the year-ago quarter. The company is expected to earn around 76 cents per share in the 2005 third quarter, up 11.7 percent from this year's second quarter.

Some down from first quarter

Anadarko's expected profit of $2.02 per share for the 2005 second quarter would be slightly below $2.05 per share earned in the previous quarter. But it would be up significantly from $1.59 per share earned in the year-ago period. Moreover, Anadarko's 2005 third-quarter profit is expected to come in around $2.09 per share, up about 2 percent from the second quarter.

Kerr-McGee's expected 2005 second-quarter profit of $2.28 per share would be significantly below the company's $2.42 per-share performance in this year's first quarter, but well above the company's $1.09 per share in last year's second-quarter. Kerr-McGee also could earn about $2.32 per share in the 2005 third quarter, up 4 cents per share from the second quarter.

Devon, largest of the U.S.-based independents, should earn about $1.20 per share in the 2005 second quarter, up from $1.12 per share in the previous quarter and up significantly from $1.01 per share in last year's second quarter. However, the company's profit could slip to $1.16 per share in the upcoming third quarter, down about 3 percent from the second quarter.

XTO's profit for the 2005 second quarter should increase to 59 cents per share from 54 cents per share in the prior quarter and from 41 cents per share in the year-ago quarter. However, company earnings in the 2005 third quarter could be flat to the second quarter.

Forest should see a significant earnings improvement of 87 cents per share in the 2005 second quarter, up from 72 cents per share in the previous quarter and up from 52 cents per share in the 2004 second quarter. However, earnings could drop about 3 cents per share in the 2005 third quarter.

Meanwhile, 2005 second-quarter earnings for Alaska Cook Inlet-operator Unocal, which is weighing separate bids for the company from Chevron and Chinese state oil company CNOOC, is expected to turn in 2005 second-quarter earnings of $1.36 per share, down sig-

see **INDEPENDENTS** *page 16*

BRITISH COLUMBIA

Energy trust buys B.C. property

A northern British Columbia oil property pumping 5,200 barrels per day of medium-gravity crude has been snapped up by Harvest Energy Trust for C$260 million.

If the deal closes as anticipated on Aug. 2, Harvest's output will climb to 40,000 barrels of oil equivalent per day and its capital budget for 2005 will increase to C$100 million.

The acquisition, from an unnamed seller, includes 19.8 million boe of proved-plus-probable reserves, of which 6 percent is natural gas, and 57,000 undeveloped acres.

The purchase price works out at C$46,200 per flowing barrel of production.

Harvest also announced that new price hedging agreements will eliminate the variability of heavy-oil differentials on prices received for its 10,000 boe per day of heavy oil.

—GARY PARK

NEW ORLEANS, LA.

MMS rejects 19 bids from lease sale, ends up collecting $342M in bonuses

Nineteen winning bids submitted in last March's Central Gulf of Mexico Lease Sale 194 were rejected by the U.S. Minerals Management Service because they did not meet the agency's standard for fair market value, MMS said June 24.

Additionally, MMS said an unidentified participant in the sale refused to accept six leases it won on sale day, resulting in the company's forfeiture of one-fifth of its bid deposit on each of the leases totaling just $674.

However, the remaining $97,000 or four-fifths of the bonuses not collected by MMS, plus the $11.9 million in rejected bids, reduced the government's adjusted take from the sale to $342.03 million from initial apparent high bids of $353.9 million.

Lease Sale 194 attracted 80 companies that submitted 651 bids on 428 exploration blocks. With the after-sale adjustments, 403 blocks were awarded. The highest bid accepted on a tract was $21.2 million by Dominion Exploration & Production and Stone Energy for West Cameron Block 132. The tract received eight bids.

—RAY TYSON

● WASHINGTON, D.C.

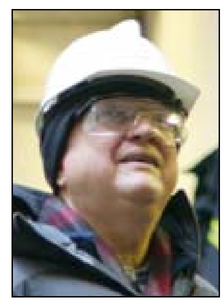
Senate approves energy bill; House battle looms ahead

By H. JOSEF HEBERT

The Associated Press

The Senate approved an energy bill June 28 that was more favorable to conservation, wind farms and ethanol and less kind to oil and gas producers than legislation passed by the House.

Whether the sharp differences can be resolved may depend on how much pressure President Bush can bring to bear. The president urged the lawmakers to resolve their differences quickly and send him a bill before August.



JUDY PATRICK

"The administration's attitude is we want a bill. I think you will see the president quite proactive on this." —U.S. Energy Secretary Samuel Bodman

"The administration's attitude is we want a bill," Energy Secretary Samuel Bodman told The Associated Press. "I think you will see the president quite proactive on this."

Hard bargaining lies ahead, especially with a pesky issue surrounding the gasoline additive MTBE remaining a potential deal breaker — as it was two years ago.

MTBE out, would be filibustered

The House, particularly Majority Leader Tom DeLay of Texas, wants to protect oil companies and refiners who produced MTBE from environmental lawsuits brought by communities whose drinking water has been contaminated by the additive. DeLay said June 28 an attempt is being made to "come up with a solution" to the MTBE issue, but provided no details.

Supporters of the Senate bill, which has broad bipartisan backing and is silent on MTBE, say such liability protection would trigger a filibuster and send the bill to defeat, as it did in 2003. Sen. Pete Domenici, R-N.M., said the House needs to work out a compromise on MTBE that can pass Senate muster.

After finishing all but a final vote on the bill in mid-June, the Senate approved the 1,250-page document June 28 with an 85-12 vote. Seven Democrats and five Republicans voted against the bill.

Despite its broad sweep, which would affect virtually every energy industry while boosting energy conservation, lawmakers acknowledged the bill would have little impact on current high gasoline and crude oil prices. Crude oil eclipsed $60 a barrel this week and gasoline averaged $2.22 a gallon nationwide, according to the Energy Department.

Bush said the Senate-passed bill would help U.S. economic growth by addressing the root causes of high energy prices and the nation's growing dependence on foreign supplies. But the bill's critics argued it does little to reduce demand for oil, two-thirds of which goes for transportation, or reduce oil imports, which account for 58 percent of U.S. demand.

40% of tax breaks to boost alternatives, conservation

More environmentally friendly than the energy bill passed by the House in April, the Senate bill would funnel 40 percent of $18 billion in tax breaks over 10 years to boost renewable energy sources, energy conservation and alternative transportation fuels.

see ENERGY BILL page 17

continued from page 15

INDEPENDENTS

nificantly from $1.62 per share in the previous quarter but also up significantly from 86 cents per share a year earlier. However, the company is expected to report earnings of around $1.31 per share in the 2005 third quarter, down about 4 percent from the second quarter.

Outside Alaska

Among the remaining large U.S. independents that do not operate in Alaska, Apache is the only one expected to see an increase in 2005 second-quarter earnings over the previous quarter, from $1.67 per share to roughly $1.73 per share. The company's 2005 second-quarter profit also should be significantly above $1.21 in the year-ago quarter. However, Apache's 2005 third-quarter earnings could drop to $1.65 per share, down about 6 percent from this year's second quarter.

Chesapeake's profit for the 2005 second quarter is expected to come in around 44 cents per share, down from 56 cents per share in the 2005 first quarter but up significantly from 33 cents per share in the 2004 second quarter. The company could post about 48 cents per share in the 2005 third quarter, up 9 percent from the previous quarter.

Burlington is expected to report a 2005 second-quarter profit of about $1.16 per share, down from $1.21 per share in the previous quarter but up significantly from 96 cents per share in the 2004 second quarter. The company's expected 2005 third-quarter profit of $1.12 per share, down about 3.4 percent from the second quarter.

Noble Energy's expected 2005 second-quarter earnings of $1.75 per share would be down from the prior quarter's $1.83 cents per share but up from $1.22 per share in the year-ago quarter. The company could earn around $1.92 per share in the 2005 third quarter, up nearly 10 percent from the second quarter.

EOG is expected to earn about 85 cents per share in the 2005 second quarter, down slightly from 86 cents per share in the previous quarter and up significantly from 52 cents per share in the 2004 second quarter. The company's third-quarter profit is expected to be roughly flat with the previous quarter.

For the most part, smaller independents included in Petroleum News' 2005 second-quarter earnings survey are expected to surpass their financial performances in both the 2005 first quarter and 2004 second quarter, according to analysts' consensus estimates. ●

● DES MOINES, IOWA

Technology may converge biodiesel, ethanol markets

New technology would transform corn oil into biodiesel

By DEVONA WALKER
Associated Press Writer

The biodiesel and ethanol markets may converge with new technology that promises to transform corn oil into biodiesel, possibly resulting in substantial growth in supply for both fuels, industry experts say.

SunSource BioEnergy LLC, a partnership of four ethanol producers — VeraSun Energy, Golden Grain, KAAPA Ethanol and Glacial Lakes Energy — and one technology company — Ethanol Oil Recovery Systems — joined to make the technology available throughout the ethanol industry. The technology will be the focus of an annual ethanol workshop July 30 in Kansas City, Mo.

"This is exciting new technology," said Don Endres, Vera Sun's chief executive officer. "We believe this breakthrough will improve the economics of ethanol production by creating another product revenue stream."

Ethanol Oil Recovery Systems developed the technology that allows biodiesel to be made from the ethanol process, by using the oil from corn that has traditionally been an unwanted addition to feed grains.

Brian Jennings, executive director of the American Coalition for Ethanol, said both fuels could go a long way to help the environment and make the United States less dependent on foreign oil.

The technology already is being used at a few plants in the Midwest and is expected to expand to other ethanol producers around the country.

By next year, construction will begin at a single distiller plant capable of producing about 50 million gallons of biodiesel per year. Last year, the industry produced about 35 million gallons of biodiesel fuel.

New facility would be largest

Though the industry is rapidly growing, the new facility would be the largest of its kind in the nation.

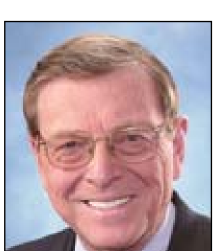
see BIODIESEL page 19

continued from page 16

ENERGY BILL

Domenici, chairman of the Senate Energy and Natural Resources Committee, said it would help diversify the country's energy and usher in "a new policy for the United States ... that energy should be clean, renewable and that we have conservation" to curtail energy demand.

Among other key provisions are:



Sen. Pete Domenici, R-N.M., chairman of the Senate Energy and Natural Resources Committee, said the bill would help diversify the country's energy and usher in "a new policy for the United States ... that energy should be clean, renewable and that we have conservation" to curtail energy demand.

- Loan guarantees of up to 80 percent for developing new technologies for clean coal and next-generation nuclear power reactors.
- A doubling of ethanol use in gasoline to 8 billion gallons a year by 2012, a boost to corn farmers.
- A requirement for utilities to produce 10 percent of their electricity from renewable energy sources, such as wind and biomass from garbage or plants, by 2020.
- Mandatory reliability standards for electric power grids, ending the current system of industry self-regulation.
- Tax breaks for people who buy gas-electric hybrid cars, more energy-efficient appliances or energy-efficient homes.

The bill skirted some of the most contentious energy issues, from drilling in the Arctic National Wildlife Refuge — which is called for in the House bill — to requiring automakers to build more fuel-efficient cars. (ANWR drilling, which has a slim majority of support in the Senate, is expected to pass as part of the budget process. If included in an energy bill, it would probably have been filibustered in the Senate, which requires 60 votes to break a filibuster.)

The energy bill passed by the Senate also avoided mandatory reductions in heat-trapping emissions to address climate change, which some senators had wanted.

The bill "is short on the truly bold action needed to break this country's addiction to foreign oil and long on the traditional boondoggles that waste taxpayer money and fail to promote energy independence," complained Sen. Ron Wyden, D-Ore., one of the dozen senators who voted against the legislation.

A number of Republicans, including Sen. Jon Kyl of Arizona, opposed the bill in part because of its cost, an estimated $16 billion in direct spending and tax breaks. That's double what the House-passed bill would cost and well above the $6.7 billion price tag the White House had wanted.

An analysis by the advocacy group Taxpayers for Common Sense said the bill would cost $55 billion over 10 years if all the programs it authorizes were actually funded by Congress. Lawmakers acknowledged many of the programs in the bill will never be given the money authorized under current climate of tight budgets.

"We're not talking about something that's enormous," said Domenici of the bill's realistic expenditures.

Bodman said he'd like to see the cost trimmed, adding, "We're going to work toward that."

He also said lawmakers need to resolve the MTBE issue. Still, he told The AP, "To the extent we have an impasse, I stand ready to step in."

In the last four years the Senate has passed energy legislation twice, only to see the effort fall apart without a final agreement with the House. Republican and Democratic lawmakers predicted that a compromise will require the close involvement of the White House. ●

WASHINGTON, D.C.

Chinese oil giant ready for scrutiny

The Chinese oil company that seeks to take over California-based Unocal Corp. said June 27 it is eager to have the U.S. government scrutinize the national security implications of the deal and said the review process was critical to the success of the proposed merged company.

CNOOC Ltd. CEO Fu Chengyu said in a letter sent to Congress that he understands "the importance of these issues" and that he wanted an opportunity to discuss them with the Committee on Foreign Investment in the United States "as soon as possible."

In mid-June, Beijing-based CNOOC made an unsolicited $18.5 billion offer for Unocal, which had already reached a tentative agreement to be purchased by Chevron Corp. for $16.6 billion. Even before the formal offer was made by CNOOC, which is backed by the Chinese government, members of Congress sent President Bush a letter warning him of the threats posed by China's "pursuit of world energy resources."

A separate letter began circulating in Congress the week of June 20, also calling on the Bush administration to investigate — through the aegis of the CFIUS — the national security implications of the proposed deal.

In his letter on June 27, Fu attempted to address some of the concerns the deal raises about America's energy security by noting that Unocal's oil and gas production amounts to less than 1 percent of all U.S. consumption.

He also reiterated his belief that CNOOC's all-cash offer would benefit the shareholders of Unocal and that substantially all of the company's U.S.-based workers would retain their jobs if the merger were completed.

Unocal shares rose 10 cents to close at $65.78 June 27 on the New York Stock Exchange. CNOOC Ltd.'s U.S.-traded shares rose 90 cents, or 1.6 percent, to close at $55.80 on the NYSE.

—THE ASSOCIATED PRESS

DALLAS

Pioneer adds to U.S. onshore assets with $177M purchase in Texas

Pioneer Natural Resources said June 28 that it has signed agreements to purchase additional assets in two of its U.S. onshore core areas, the Permian basin and South Texas.

The agreements, with two parties, are for approximately $177 million; the transactions expected to close within 30 days.

The company said it expects production from the acquired assets could exceed 10,000 boe per day upon full development.

Pioneer said it is purchasing approximately 70 million barrels of substantially undeveloped proved oil equivalent reserves with daily production of some 1,800 barrels of oil equivalent and an estimated 800 undrilled locations, and will invest approximately $400 million over the next five years to develop the acquired proved reserves, accelerating the pace of drilling in each of the areas beginning later this year. The company said it expects production from the acquired assets could exceed 10,000 boe per day upon full development.

"We already own a minority interest in more than 80 percent of the producing wells and development locations included in these acquisitions and are very pleased to add these low-risk assets to our onshore portfolio," said Pioneer Chairman and Chief Executive Officer Scott Sheffield. "These transactions provide new opportunities that are an excellent fit with our existing assets allowing us to leverage our expertise, consistent with our long-standing core area acquisition strategy."

SAN RAMON, CALIF

Chevron's Unocal takeover bid clears SEC hurdle

Chevron Corp. said June 29 that its proposed $16.4 billion takeover of rival Unocal Corp. has cleared its final regulatory hurdle, meaning the offer now hangs on a shareholder vote on Aug. 10.

El Segundo, Calif.-based Unocal originally accepted Chevron's bid but is also now considering a higher, $18.5 billion offer from China's state-owned oil company CNOOC Ltd.

The Securities and Exchange Commission has cleared Chevron's registration statement for the transaction, the company said. This was the final U.S. regulatory requirement following the Federal Trade Commission's approval of the deal. Unocal said shareholders of record from June 29 will be eligible to vote on the buyout.

Chevron shares fell 31 cents to $56.69, while Unocal shares slipped 40 cents to $65.39 in midday trading on the New York Stock Exchange. CNOOC's American depositary shares rose 11 cents to $59.11 on the NYSE.

—THE ASSOCIATED PRESS

KUWAIT

OPEC will watch price before going ahead with 500,000 barrel increase

OPEC's president said June 25 that the cartel would watch oil prices further before deciding whether to increase the output ceiling.

Sheik Ahmed Fahd Al Ahmed Al Sabah, who is also Kuwait's oil minister, spoke to reporters on the sidelines of a parliament session.

"I think we've got to wait for a while to see exactly what is the behavior of the prices, because until now it's not clear," he said. "When you (keep) following the prices, they are moving up and down."

Al Sabah said he spoke June 24 by phone with his Saudi and Qatari counterparts on the possibility of increasing OPEC production ceiling and was also calling other OPEC ministers for their opinions.

"We've already started consultations but the prices now started to come back to normal and this is what we were thinking (would happen)," Al Sabah said.

"I hope very soon we will have an opinion on what will be the situation," he said, adding that he couldn't give a specific timing for a decision on the possible increase.

June 20, Al Sabah said that if oil prices stayed at record highs, OPEC would start consultations June 24 to increase production by 500,000 barrels a day.

Crude oil futures ended a strong week at a new settlement high of just under $60 a barrel June 24, lifted by rising fear that petroleum demand will outpace supply.

Benchmark crude futures for August delivery on the New York Mercantile Exchange closed at $59.84 a barrel June 24, a new settlement record for a front month contract since crude futures began trading on the exchange in 1983.

Asked about the $60-barrel highs of the last few days, Al Sabah said he expected the price to drop to a normal level, referring to $50-51 as normal.

In mid-June the oil cartel agreed to raise its official production ceiling to 28 million barrels, starting July 1. Including Iraq, which is not bound by the quota system, OPEC is pumping close to 30 million barrels a day, or about 35 percent of global demand.

—THE ASSOCIATED PRESS

NORTH SLOPE

XTO Kuparuk lease shares go to Conoco

The Alaska Department of Natural Resources has approved assignments of small working and royalty interests in Kuparuk River unit leases from XTO Energy to ConocoPhillips Alaska.

Gary Simpson, XTO senior vice president of investor relations and finance, said the assignments were part of a trade XTO completed with ConocoPhillips in March. Those producing properties, XTO said in a March release, were located primarily in Texas and New Mexico. XTO acquired working interests in its operated properties in the East Texas Freestone trend, the San Juan basin and the Goldsmith field in the Permian basin.

XTO said it conveyed to ConocoPhillips "non-strategic interests in COP-operated properties in the San Juan and Permian basins, along with a fractional interest in Alaska."

XTO said it conveyed to ConocoPhillips "non-strategic interests in COP-operated properties in the San Juan and Permian basins, along with a fractional interest in Alaska."

The Kuparuk River unit lease interest conveyed to ConocoPhillips was a 0.1086 percent working interest and a 0.0905 percent royalty interest, acquired by XTO from Chevron in 2004.

continued from page 17

BIODIESEL

There are currently 85 ethanol plants nationwide, producing about 3.8 billion gallons. Another 15 are under construction.

"The ethanol industry is the fastest growing industry in the state of Iowa," said Lucy Norton, a spokeswoman for the Iowa Corn Growers Association. "We've seen that the industry has been setting record production levels."

Norton said the new technology will offer a very attractive alternative to existing ethanol producers.

"This will significantly diversify the market and give them a greater opportunity of seeing a return on their investment," she said. "And it will keep more of that income in the state of Iowa."

VeraSun Energy, headquartered in Brookings, S.D., owns and operates a 120 million gallon ethanol plant in Aurora, S.D. It will complete construction of a 110 million gallon plant near Fort Dodge, Iowa, later this year. When completed, the plant will make VeraSun the second largest ethanol producer in the country.

"The real benefit to using alternative fuels is that it reduces the emissions," said Matt Janes, vice president of technology. "That's the huge benefit and the main reason that it is coming on so strong right now."

This is the first time the ethanol and biodiesel markets have merged, and advocates for both fuels say it's a perfect blend.

Brian Jennings, executive director of the American Coalition for Ethanol, said both fuels could go a long way to help the environment and make the United States less dependent on foreign oil.

"It's produced in the United States, so we don't have to depend upon a foreign nation to supply this to us," Jennings said. "It's homegrown." ●

continued from page 1

INSIDER

telling attendees what he had just told the governor – that Shell hopes to become a major player in Alaska.

"I messed up," the governor said June 29, admitting with a chuckle that he felt a bit sheepish.

In the meantime, Petroleum News tried to figure out which company the governor was referring, not suspecting it was Shell since the company had already begun picking up leases in Alaska and top executives in the company had previously announced Shell's intentions regarding Alaska, albeit not directly to the governor.

The most promising candidate was ENI SpA – pronounced "any" – a major oil and gas company based in Italy.

ENI officials have been interested in Alaska for well over a year and Petroleum News sources all placed their bets on the Italian company being the next big new player in Alaska.

Some sources said they expected ENI to buy EnCana's leases in Alaska, but EnCana would not confirm a deal is in the works, although all its Alaska leases have been on the market for several months.

The governor might have been a bit late with his announcement about Shell, but his prediction could still prove true, sources say, especially if the rumors about EnCana prove true.

Shell opening Alaska office

ALTHOUGH THERE HAS BEEN no formal announcement, word on the street is Shell has taken over EnCana's office space in Anchorage and hired EnCana's top man in Alaska, Tom Homza.

Petroleum News sources at both companies would not confirm the rumor. But Kelly op de Weegh, senior external affairs representative for Shell, did say the company is "negotiating for office space in Anchorage" and "will make an announcement at an appropriate time."

So, is Shell buying EnCana's leases in Alaska, all of which are up for sale?

Petroleum News sources say there is not a lease deal in the works between the two companies. Op de Weegh said, "Shell did not acquire any leases from EnCana."

She also said Shell does not yet have a partner for its Beaufort Sea leases, something company officials have said they would like to find.

PetroKaz ready to pack its Kazakh bags

TIRED OF BATTLING WITH ITS RUSSIAN partner and the Kazakhstan government, PetroKazakhstan is looking for a way out of its misery.

The smallest of Canada's six integrated oil companies, but the toughest in the challenges it has taken on, PetroKaz said June 27 it is in talks with a number of parties about a merger or sale.

With a market value of about C$3.5 billion and interests in the former Soviet republic that include 550 million barrels of proved and probable reserves, capacity to pump about 158,000 barrels per day (although disputes have currently limited output to 85,000 bpd) and its own refinery, PetroKaz is seen as a ripe takeover target.

For five years it has been on a wild ride in Kazakhstan, including a brief takeover of the refinery in 2000 by armed mercenaries, whose origin remains murky.

Since then it has faced civil and criminal charges by Lukoil, its Russian partner in the Turgai oilfield, and Kazakh authorities, raising suspicions that its hosts were trying to beat it into submission.

In response to a report in the Financial Times of London, a spokesman for PetroKaz confirmed that Goldman Sachs was hired more than a year ago to act as a general financial adviser.

He said that "we have received a number of approaches from various companies," although there is no assurance that "this will lead to any kind of formalized, final transaction."

Analysts believe suitors will come from several directions — Lukoil, KazMunaiGaz (Kazakhstan's stated-owned company), India's state-owned ONGC Videsh, ENI SpA of Italy, Chevron (which is active in the region), or one of China's large energy companies that are scouring the globe for oil interests.

The Financial Times said an unidentified Chinese firm has made an offer, but PetroKaz has declined to name any bidders.

Bolstering the Chinese theory is the current construction of a 600-mile crude pipeline by China and KazMunaiGaz from Kazakhstan to a Chinese refining center on Xinjiang, eliminating the current costs of shipping oil by rail.

The pipeline is scheduled to come on stream in 2006 at 200,000 bpd and double those volumes by 2011.

PetroChina is also obtained approval to spend more than US$3 billion upgrading its refining complex in Xinjiang.

Whatever the outcome, there is strong reason to believe that PetroKaz is headed for the history books.

Rightly or wrongly, Chief Executive Officer Bernard Isautier — credited with rescuing PetroKaz from bankruptcy when it was known as Hurricane Hydrocarbons — was seen as dropping hints last year when he cashed out stock options worth C$92.6 million, then announced in May that he will retire in September.

Clark assigned to role of chief gas line negotiator

ALTHOUGH NO ONE IS SAYING he's been "replaced," it looks as though international energy consultant Pedro van Meurs is being supplanted by Jim Clark as lead negotiator for the State of Alaska on a North Slope natural gas pipeline.

Alaska Gov. Frank Murkowski made the formal announcement on June 29, saying Clark, his chief of staff, would delegate some of his normal duties to commissioners in order to focus most of his time on wrapping up fiscal terms for a pipeline with at least one of the three applicants under the state's Stranded Gas Development Act in order to present a contract proposal to the Legislature "this year."

Murkowski said that he, with Clark at his side, has attended "virtually all of the meetings" with the applicants and that he wants his number one person to coordinate the final stages of gas line negotiations for his administration.

Clark's new unofficial title, the governor said, is "chief counsel, chief negotiator and chief of staff," quelling rumors that Cheryl Frasca, director of the state Office of Management and Budget, had been named Clark's replacement as chief of staff.

But the announcement instigated speculation on the role of van Meurs, who was hired in April 2003 by the Alaska Department of Revenue, and who has often been referred to as lead gas line negotiator by state officials.

"Pedro is still an adviser, a consultant," the governor said in response to questions from the press following his announcement of Clark's added responsibilities, noting that van Meurs "travels back and forth to the Middle East … for other clients."

Without directly saying Clark was replacing van Meurs, Murkowski instead dwelled on van Meurs contribution to date: "We value his input … he has been a great asset."

EnCana: 'We're No. 1, we're No. 1'

SKY-HIGH OIL AND GAS PRICES kept the largest producers among the top ranks of Canada's most profitable publicly traded companies in 2004.

The Globe and Mail's annual Top 1000 list saw EnCana retain its No. 1 spot, while peer companies filled eight of the leading 25 positions.

EnCana was a clear winner again, posting profits of US$3.513 billion, putting itself well clear of the second place Bank of Nova Scotia with C$2.93 billion (about C$2.37 billion at current trading levels).

ExxonMobil subsidiary Imperial Oil, Canada's largest integrated oil company, moved from ninth in 2003 to eighth spot at C$2.03 billion.

Otherwise eight of the top 10 positions were filled by Canada's five largest banks and two life insurance companies.

Other E&P companies to claim places among the leading 25 were: Petro-Canada (10th, unchanged from 2003) at C$1.76 billion, Canadian Natural Resources (dropping to 16th from 12th) at C$1.4 billion, Shell Canada (rising to 19th from 26th) at C$1.29 billion, Suncor Energy (slipping to 21st from 18th) at C$1.1 billion, TransCanada PipeLines (unchanged at 22nd) at C$1.08 billion, TransCanada Corp. (unchanged at 23rd) at C$1.03 billion and Husky Energy (tumbling to 24th from 13th) at C$1 billion.

There is no reason to expect much change in profit levels this year given the latest projections for one entity that neither drills for nor produces oil and gas, but reaps a handsome reward from the industry.

The Alberta government is likely to pile up a surplus of C$5 billion-$6 billion for 2004-05, far ahead of its budget prediction of C$1.5 billion, said DeltaOne Capital analyst Peter Linder

The budget was based on the government's traditionally conservative forecasts of US$42 per barrel of oil and C$5.60 per gigajoule of natural gas. ●

Editor's note: Insider is written by Gary Park and Kay Cashman.

continued from page 1

MACKENZIE

project could be scheduled.

In a letter to the federal court on June 20, the Deh Cho asked to postpone their lawsuits seeking a greater role in the environmental review process, indicating progress in their talks with Ottawa.

There have been reports a deal might include a C$15 million economic development fund for the 4,500 residents of Deh Cho communities, but there has been no comment from either side beyond confirmation that negotiations are proceeding.

Northwest Territories' Premier Joe Handley has told reporters that the federal government has also offered to cost-share a socio-economic impact fund with his government to meet the Northwest Territories' demand for C$100 million a year to until Ottawa is prepared to hike its allocation of resource revenues to 40 percent from 4 percent.

Handley has delivered a blunt message to the federal government: The Northwest Territories wants a percentage of resource revenues, not a fixed amount.

He is also unhappy about the prospect of diverting Northwest Territories' money into a socio-economic fund.

Separately, Stephen Kakfwi, chief negotiator for the Kahsho Gotine community based in Fort Good Hope, is pressing ahead with his case for 5 percent or about C$40 million a year of revenue generated by the pipeline to be channeled to aboriginal groups.

Environmental groups

Meanwhile, the Yellowknife conference again hammered home a concern among environmental groups that, despite supplementary information from the Mackenzie consortium this year, they want more information on the project's impact on climate change, permafrost, stream crossings and the Mackenzie River.

In February, the Joint Review Panel identified shortcomings in the Mackenzie consortium's initial regulatory filing and said that those information gaps were closed, so the panel would not schedule hearings. Panel chairman Robert Hornal, in his opening remarks to the Yellowknife conference, said the panel has "received a substantial amount of supplementary information."

He also said that the panel has made "substantial progress" over the past 10 months on its environmental review, along with registering 93 people and organizations as interveners in the review process.

Hornal said the panel would confine itself to an observer role at the Yellowknife session, then review all of the information it has received before deciding whether to proceed to public hearings.

He said that decision would be a "judgment call that the panel must make for itself."

—GARY PARK

Companies involved in Alaska and western Canada'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

FORREST CRANE

Darryl Townsend, Lead Planner/Scheduler

NANA/Colt Engineering

The staff of this relatively new company, NANA/Colt Engineering, has an experience level that stretches well beyond NANA/Colt's years of operation. Many designers and engineers have more than 20 years of Arctic experience. It offers a broad range of engineering, project management and business services, yet has a small company "family" feel in its management style.

Houstonite Darryl Townsend earned his BS in mechanical technology at the University of Houston and has been with NANA/Colt 10 years. In his lead planner and earlier capacities he worked on the Alpine, Kuparuk and Prudhoe projects. Wife Beckey also hails from Houston. The Townsends are enjoying rearing their three children in Alaska. Darryl sings in the church choir when not hiking, biking, skiing or snowmobiling.

FORREST CRANE

Marcie Compton, Project Manager

AeroMap US

AeroMap US is a geographic information and mapping sciences company focused on the earth's surface. From data acquired using land, airborne and satellite sensors, AeroMap chronicles conditions, defines the earth's topographic shape, and identifies and measures its natural and man-made features. AeroMap's GIS services make raw data useable by helping customers manage, visualize and understand their world.

Marcie Compton has 11 years' experience with GIS, seven with AeroMap. Before moving to Anchorage, she did GIS-related work for industry and government. She's an organizer for the Alaska Surveying and Mapping conference and enjoys speaking to organizations about current spatial technology. Marcie and her husband Marty have two sons, Will and Rowan, and enjoy travel, fishing and reading.

continued from page 1

RUN

Juniors average 16 percent increase

The survey, which defined juniors as companies producing 500 to 15,000 barrels of oil equivalent per day, said those firms posted average share value increases of 16 percent in the first quarter, compared with 8 percent by the trusts.

In total, the 83 juniors contributed 213,000 boe per day of Canadian production and the trusts were responsible for 750,000 boe per day. (The trust ranks have since expanded to 35 and the output to more than 900,000 boe per day).

Current combined volumes amount to about 25 percent of Canada's total oil and gas production.

Iradesso also concluded that the median gas weighting of the juniors was 69 percent, compared with 53 percent for trusts. With that balanced portfolio, trusts should be able to prolong a steady, long-term cash flow to fuel their monthly distributions to investors.

On an enterprise value per flowing boe, the median for trusts was C$66,400 per boe per day, just fractionally ahead of the C$63,100 for juniors.

Juniors' equity issues up

While the trusts have attracted most of the attention in recent years, junior start-ups, often with seasoned management teams at the helm, raised C$1.9 billion in 172 equity issues in the first four months of 2005, C$400 million more than for all of 2004.

Sayer Securities, which tracks M&As and the capital financing market, said the juniors paid a median C$47,000 per flowing barrel for assets.

But that standard is fast disappearing, confirming the comments of Martin Peters, chief executive officer of Enermarket Solutions, who said anyone hoping to base a deal on 2004 prices was "on the wrong page."

Just how far off base is reflected in a couple of recent transactions when Capital Energy acquired Tiger Energy for C$76,000 per flowing boe and Freehold Royalty Trust easily topped that figure by paying C$93,000 per flowing boe for Canadian Natural Resources properties.

Despite efforts by companies such as investment banker Tristone Capital to rebundle assets into packages of C$15 million or less that are more easily absorbed by juniors, the market is beyond the reach of many.

StarPoint Energy Chief Executive Officer Paul Colborne thinks the inevitable outcome will be a wave of consolidation over the next three to five years as trusts find themselves buckling under higher cost structures, steeper asset declines, overleveraged balance sheets and inadequate price hedging programs.

Colborne said StarPoint has hedged half of its production until 2007 to protect against a three-way rise in inflation, interest rates and the Canadian dollar along with any drop in commodity prices.

He said that should allow StarPoint to distribute 21 cents per unit even if oil falls below US$30 per barrel.

Peters & Co., a Calgary-based investment dealer, believes that so long as crude remains above US$40, most trusts will be able to sustain their distributions.●

continued from page 1

PROFITS

Another 35% in third quarter

However, an ever-tightening rig market on increasing energy demand and escalating day rates appear to have put both land and offshore contractors in the driver's seat during the 2005 second quarter. Moreover, industry analysts now project company earnings on average will jump another 35 percent in the 2005 third quarter versus the second quarter.

Estimates for the 2005 second quarter and beyond represent mean earnings projections of analysts polled by Thompson-First Call. However, individual company estimates can be higher or lower than the consensus and tend to change as the reporting season approaches. Estimates also generally exclude one-time charges against earnings and other special items.

Contract drillers included in Petroleum News' 2005 second-quarter survey are Transocean, Diamond Offshore, GlobalSantaFe, Rowan, Ensco International, Pride International, Nabors Industries, Parker Drilling, Noble and Grey Wolf.

Transocean, the world's largest offshore drilling contractor, is expected to report a 2005 second-quarter profit of around 33 cents per share, up roughly 37 percent from 24 cents per share in the previous quarter and up three-fold from 8 cents per share in the year-ago quarter. The company is expected to earn about 46 cents per share in the upcoming third quarter, an increase of nearly 40 percent from this year's second quarter.

GlobalSantaFe, another large offshore drilling company, could see a 2005 second-quarter profit of 27 cents per share, an increase of 28.6 percent from 21 cents per share in the prior quarter and a huge leap from the year-ago quarter, when the company lost 1 cent per share. Also, GlobalSantaFe is expected to earn around 50 cents per share in the 2005 third quarter, a whopping 85 percent increase from the second quarter.

Diamond is another offshore drilling contractor that has dug itself out of the red. Analysts expect the company to make about 29 cents per share in the 2005 second quarter, up 26 percent from 23 cents per share in the previous quarter and a loss of 8 cents per share a year ago. Additionally, Diamond is projected to earn 46 cents per share in the 2005 third quarter, a nearly 60 percent increase from the previous quarter.

Rowan, with its powerful fleet of relatively shallow-water jack-up rigs, is primed to earn about 31 cents per share in the 2005 second quarter. That would represent a 24 percent increase from 25 cents per share earned in the 2005 first quarter and another giant leap from the 2-cent-per-share loss registered in the year-ago quarter. The company also is expected to push its 2005 third-quarter profit to around 40 cents per share, a nearly 30 percent increase from this year's second quarter.

A 35% gain likely for Ensco

Ensco, which also owns a fleet of powerful jack-ups capable of drilling to great depths, is expected to earn a 2005 second-quarter profit of about 35 cents per share. That would be a healthy 35 percent increase from 26 cents per share in the prior quarter and a nearly three-fold jump from 12 cents per share in the second quarter of 2004. Ensco is projected to earn about 46 cents per share in the 2005 third quarter, representing a roughly 30 percent increase from the second quarter.

Noble, primarily an offshore drilling contractor should see its 2005 second-quarter profit jump to 55 cents per share, an expected 66 percent increase from 33 cents per share in the previous quarter and more than a two-fold increase from 26 cents per share a year earlier. Company earnings also are expected to increase to 70 cents per share in the 2005 third quarter, a 27 percent increase from the previous quarter.

Nabors Industries, primarily a land drilling contractor, is expected to earn about 72 cents per share in the 2005 second quarter, a 10 percent decrease from 80 cents per share in the previous quarter but more than a two-fold increase from 30 cents per share a year earlier. The company also is projected to make 85 cents per share in the 2005 third quarter, an 18 percent increase over the previous quarter.

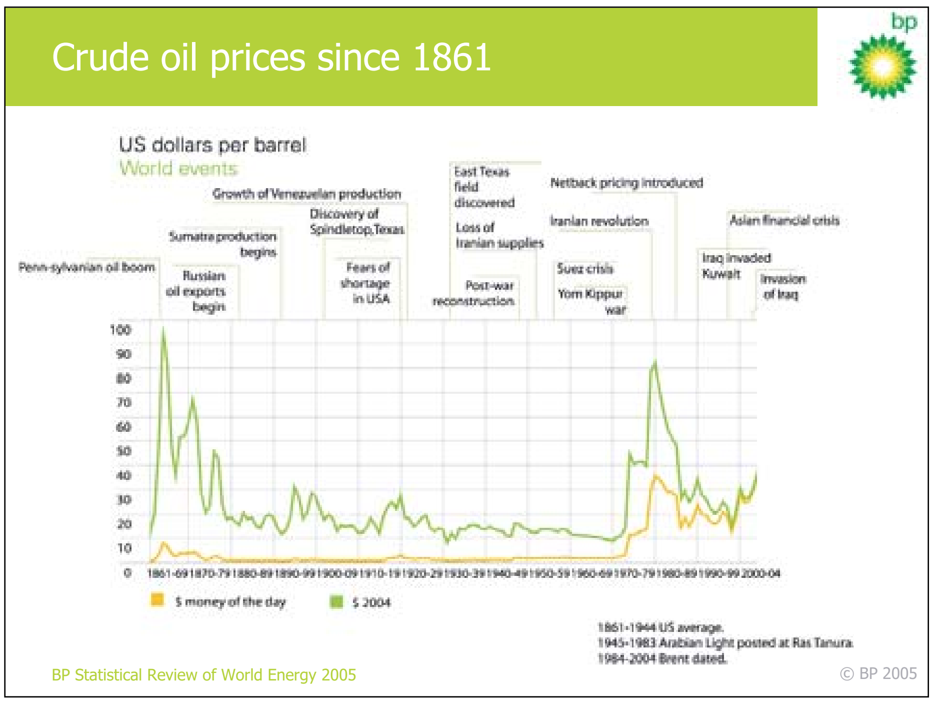
Parker, which has both onshore and offshore drilling rigs, is expected to post a slight decline in 2005 second-quarter earnings of about 4 cents per share, down from 5 cents per share in the preceding quarter but up from a 6 cent-per-share loss in the year-ago quarter. The company is expected to earn 5 cents per share in the 2005 third quarter, up one cent from the previous quarter.

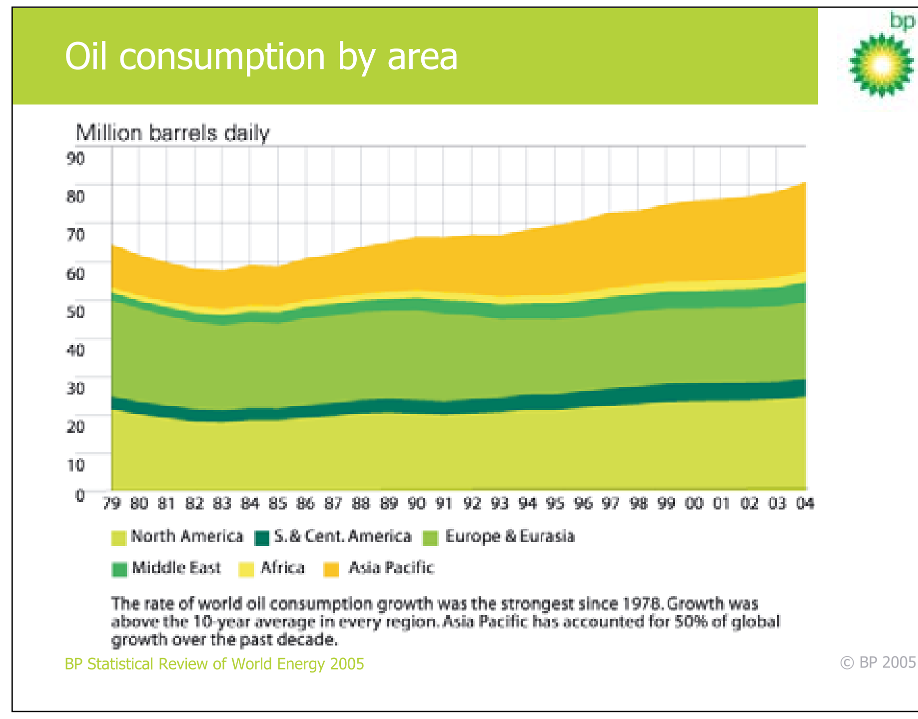
Pride, which also provides both onshore and offshore rigs, could earn about 13 cents per share in the 2005 second quarter, representing a 30 percent bump from 10 cents per share in this year's first quarter and a two-fold increase from 6 cents per share in the 2004 second quarter. The company is expected to earn a profit of roughly 22 cents per share in the 2005 third quarter, nearly doubling its second-quarter performance.

Grey Wolf, a strictly U.S land driller, is expected to earn about 11 cents per share in the 2005 second quarter, a slight increase over 10 cents per share in the previous quarter but a considerably better showing than a 1-cent-per-share loss in the year-ago period. The company could earn about 13 cents per share in the 2005 third quarter, an improvement of 2 cents per share from the previous quarter.

Service firms up 47% from last year

Meanwhile, a Petroleum News survey of major oilfield service companies Halliburton, Schlumberger, Baker Hughes, Weatherford International, National Oilwell Varco and McDermott International indicates the group on average should report 2005 second-quarter profits roughly flat to the previous quarter but up a healthy 47 percent from the same quarter last year. Moreover, earnings on average should increase about 12 percent in the 2005 third quarter compared to the second quarter. ●





continued from page 1

BP REVIEW

"It was above the 10-year average for every part of the world and for every fuel type that we track," Finley said.

However, the growth in energy usage was most rapid outside the countries with mature industrial economies, he said.

Energy usage in 2004 drove up oil consumption.

"Outside of China we estimate that the very strong economic growth we saw last year boosted oil consumption by about 0.5 million barrels per day beyond what you would see in a normal year," Finley said.

Worldwide oil production increased in response to these demands for fuel. Although the production increases have come from a broad assortment of countries, growth has been particularly notable in Russia and the deep waters of the Atlantic. But production from mature industrial countries such as the United Kingdom, the United States and Norway declined. OPEC countries have increased their production, led by increased production from Iraq.

"(OPEC production) reached a record level last year of 33 million barrels per day," Finley said.

But because world economic growth has slowed by about a percentage point in the past year, the BP analysts don't think that energy usage will escalate as rapidly in 2004 as it did in 2005.

Increasing carbon emissions

With so much of the world's energy coming from oil and other fossil fuels, a rapid growth in carbon emissions has mirrored the growth in energy usage — carbon emissions have increased throughout the world by about 25 percent since 1990, the base point for the Kyoto Protocol. Countries that ratified the Kyoto Protocol have increased their emissions somewhat less than other countries.

Carbon emissions increased by 4.5 percent in 2004.

"The rate of growth in carbon emissions (in 2004) … was the fastest growth rate we've seen since 1976," Finley said. "In volume terms the amount of carbon emitted was the highest ever."

Worldwide there's a strong correlation between economic growth and carbon emissions, he added.

The China factor

China's booming economy and that country's increasing energy demands especially impact the markets for oil and coal. Although in the past China has been self-sufficient in energy, the country had to start importing energy in 1995. And China is now the world's third largest oil importer, with imports leaping by 800,000 barrels per day in 2004.

"Since 2000, and especially since 2002, energy growth has surged in China," Finley said. "China's been in the midst of an energy-intensive period of economic growth."

Coal, however, remains China's primary fuel. There was a surge in Chinese oil needs in 2004 but this partly resulted from coal supply constraints, while continuing and rapid increases in the number of vehicles on China's roads are pushing up the demand for refined petroleum products.

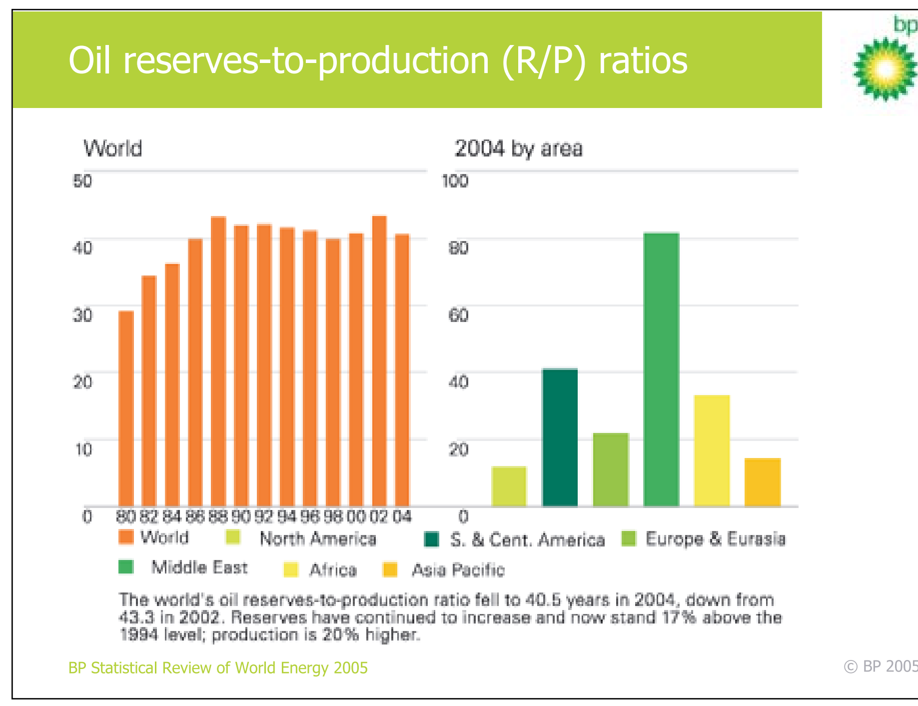
"Both gasoline and diesel consumption have risen by about 20 percent last year," Finley said.

Total Chinese energy usage grew by a little over 15 percent in 2004, as compared with 2.8 percent in the rest of the world. But, because China only accounted for 13.6 percent of total world energy consumption, the total quantity of energy used increased more outside China than inside China.

Finley also pointed out that demand for energy in China has been somewhat erratic in the past few years and actually fell between 1997 and 2000. The 15 percent growth in 2004 was a slight slowdown in growth rate from previous years; initial data for 2005 suggest that the surge in demand for oil in China is slowing somewhat.

Not the highest real prices

Although high oil prices have hit the headlines in the past year, Finley said that after taking inflation into account the recent prices are not in fact as high as those in the price peaks between 1974 and 1985 — in real terms the price of oil reached $82.15 per barrel in 1980, according to the BP review.



But prices have clearly escalated recently and Finley pointed out several reasons for this phenomenon.

"We think that there are a variety of both fundamental supply-and-demand causes and items playing into market expectations that are all mutually reinforcing," he said.

However, it's clear that the strength of demand growth was a contributing factor — supplies increased to meet the growing demand but at the cost of drawing down the surplus capacity that forms a cushion against unexpected fluctuations in supply or demand.

"It's understandable that (as a result of lack of spare capacity) the market would be nervous and bid prices up," Finley said.

Concerns about the difficulty of increasing the spare capacity have also driven oil futures to high levels. In addition, OPEC appears to have abandoned its earlier price targets for oil and has been cutting production at relatively high prices.

Crude oil quality differentials, the 2004 hurricane Ivan, the increasing tendency to view commodities such as oil as investment instruments and geopolitical concerns have all contributed to the price trends,

see **BP REVIEW** *page 24*

continued from page 23

BP REVIEW

Finley said.

So far the ramp up in oil prices seems to have had little impact on oil demand and supply. Oil industry investment has increased to record levels and is growing rapidly. But lead times to bring new production on stream tend to be very long.

Not running out of oil

Although the recent run up in the price of oil might imply a world oil shortage, that is definitely not the case, Finley said. Pressure on oil supplies has resulted from production capacity constraints and not from a shortage of known oil reserves.

In fact the Statistical Review data show that proved reserves of oil continue to increase — reserves for 2004 have sustained about the same levels as in 2003, despite rapid oil consumption.

"Proved reserves of oil, gas and coal remain more than adequate to meet the world's growing need in aggregate for the immediately foreseeable future," Finley said. "Oil has a reserves-to-production ratio of a little over 40 years, gas of 67 years and coal of 165 years."

And those figures don't take into account new technologies that will enable the development of additional reserves in the future, he said.

Natural gas markets

Finley said that natural gas was the slowest growing of all fuels last year but that there are two distinct markets for gas: North America and the rest of the world.

Supply constraints in North America have held down gas consumption for most of the last decade.

"LNG imports are rising but they still only represent about 3 percent of the total consumption," Finley said.

But there is a growing demand for natural gas for power generation, he said.

"With supply relatively fixed that can only come at the expense of bidding prices higher until other sectors of the market exit," he said. "In fact what we've seen is that industrial sector gas consumption in particular has been declining for several years although it did inch up slightly in 2004."

And gas prices in North America grew less quickly than oil prices in 2004.

Outside North America, where gas is the preferred fuel, consumption rose by 4.5 percent and prices rose more sharply.

Coal

Gas competes with oil in the United States and globally it competes with coal. In 2004 coal consumption grew, mainly in the Asia Pacific region and coal prices rose by 70 percent. China dominates coal markets and accounts for one third of world coal consumption.

"The fossil fuel that saw the most rapid price increases last year was coal," Finley said.

Increasing transportation costs formed a major component of the increase in coal prices, he said.

Nuclear power output increased by 4.4 percent in 2004. This increase resulted from Japanese reactors coming back on line after maintenance, the commissioning of some new nuclear plants worldwide and improved operating efficiency in the United States.

Hydroelectric power only accounted for about 6 percent of total energy production in 2004 but hydroelectric output grew by about 5 percent. Growth resulted from a combination of new capacity coming on stream and high rainfall in some parts of the world.

Overall, the generating capacity of other renewable energy sources such as wind power and solar power is growing rapidly, but from a very small base.

Increasing energy trade

Major increases in global energy trading have paralleled worldwide concerns about energy security and energy supplies in the past few years.

"(Global energy trading) has grown on average about 4.5 percent per year for 20 years running — twice the rate (of growth) of underlying energy consumption," Finley said.

Major energy importing blocks in North America, Europe and Asia Pacific have increased their dependence on energy imports, while the Middle East, the former Soviet Union, Africa and Latin America have increased their exports.

Eighty percent of international energy trading involves oil and 54 percent of that oil comes from the Middle East. However, diversification in world oil markets has left the Middle East share of the oil market relatively constant despite the rising global consumption of the past few years.

And although the energy trade has increased, the market structure for energy consumption has changed relatively little in the past 40 years and shows little indication of change as we move into the future. Oil dominates the market, with coal and gas vying for second place — gas has been gaining ground relative to coal. Hydroelectric and nuclear power each account for about 6 percent of world energy production.

"These trends look set to continue into the foreseeable future unless something new intervenes to change course," Finley said.

Energy security concerns, climate change and environmental considerations all might trigger changes in future patterns of energy usage, Finley said. The BP review doesn't attempt to predict the future, although Finley did point out that, regardless of any pressure for change, it does take time for "the capital stock of the industry to turn over."

"2004 was the year when energy was demand driven," Finley said, "… but it's important to note that supplies were maintained and … we did not see shortages of energy in 2004 despite high prices.

"World energy markets are now, however, in a new place — a new starting point of tight capacity and high prices."

The complete BP Statistical Review of World Energy 2005 is on the Web at www.bp.com/statisticalreview. ●