No small task

Exxon: Industry must cough up $200B a year to meet future energy demand

By RAY TYSON
Petroleum News Houston Correspondent

ExxonMobil believes sufficient oil and gas resources exist today to fuel global economies well into the century. But the company also says finding, developing and transporting them to market would require a staggering $200 billion a year in investment through 2030, the reach of the company’s latest industry forecast.

“The world’s remaining oil resources are huge,” ExxonMobil President Rex Tillerson declared. “But meeting this challenge will be a considerable undertaking for the industry.”

Tillerson also told analysts at the Dec. 7 at the Toronto Stock Exchange-sponsored Energy Oil/Gas Virtual Forum that at current energy growth rates of 1.7 percent a year, the world would need to produce 335 million barrels of oil equivalent by 2030, representing more than a 50 percent increase from today’s 220 million barrels of equivalent per day.

It’s the first time ExxonMobil has released a forecast stretching to the year 2030. Previous forecasts looked out only to 2020.

“The known resource base is adequate to supply this growth but significant investments will be needed to deliver it,” Tillerson concluded.

Estimates include both conventional and unconventional

He said that while the actual amount of oil in place is unknown, reserve estimates for conventional oil see TASK page 18

Working on solutions

Oil sands players ready to debut new Western Canadian blend, EnCana explores Ohio refinery upgrade with Premcor to open up U.S. market

By GARY PARK
Petroleum News Calgary Correspondent

A flurry of announcements involving another C$12 billion in major oil sands ventures in Alberta has been accompanied by indications that the sector is working on solutions to keep costs in check and find new ways to get their production to markets in the United States.

In less than a week, Imperial Oil said it will seek regulatory approval next year for an C$8 billion project to market the company’s Alberta Oil Sands output over the next decade. In total the three schemes are associated with another 410,000 barrels per day of synthetic crude output over the next decade.

Almost submerged in that wave were two developments that signal new trends in handling and processing the overflowing oil sands volumes. EnCana is working on a venture to process oil sands production at Premcor’s Ohio refinery and by mid-December new Canadian heavy crude blend that could open up all of North America to oil sands outspend C$400 million retooling an upgrader to slash sulfur dioxide emissions.

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ConocoPhillips task force works to lower NPR-A drilling costs

A CONOCOPHILLIPS ALASKA TASK FORCE, headed by Rick Mott, the company’s vice president of exploration and land, is looking for ways to lower the cost of exploration in the National Petroleum Reserve-Alaska. Contractors are being asked to come up with new ways of doing things in NPR-A where the cost of logistics often rivals the cost of drilling as ConocoPhillips and its partners move farther west into NPR-A.

One of the solutions being discussed is using an aircraft similar to the Sikorsky Skycrane to haul in drilling equipment and supplies—something that was done in the early days of exploration on the North Slope. See the adjacent 1969 photo of a Sikorsky Skycrane which was owned and operated in Alaska by Era Aviation. The Skycrane, which has a 20,000 pound lift capacity, was used to haul in all types of equipment, including drilling rigs in large sections. Another option being considered is barging in drilling equipment and all-terrain vehicles (such as rolligons) during the summer and then waiting for the ground to sufficiently harden to launch operations.

ConocoPhillips Alaska spokeswoman Dawn Patience told Petroleum News that the task force is expected to be finished with its analysis by the end of the 2004-2005 North Slope winter drilling season.

INSIDER

Husky admitted it was discussing a possible takeover deal with Total that apparently fizzled when the French giant walked away, unable to meet the price expectations of Hong Kong tycoon Li Ka-shing, who personally and through his family owns 71 percent of Husky.

No sooner had the rumor mill settled down than Husky, under pressure from the Toronto Stock Exchange, stunned the Canadian oil patch by disclosing it was in talks with PetroChina, the publicly traded subsidiary of state-owned China National Petroleum, which accounts for two-thirds of China’s oil and gas production.

Again the deal making evaporated as Husky shares made a sharp run-up and the Chinese reportedly found the price too much to swallow.

What has changed since is China’s hunger for energy that its struggling domestic industry can’t satisfy as oil imports surge 40 percent ahead of last year. Husky was quick to expect China to rely on imports for 60 percent of its oil supply by 2020, compared with 36 percent today.

All of which makes Husky, given its Hong Kong ties and operations in the South China Sea along with its rich holdings in Canada’s heavy oil sector, a desirable asset. But the November rumor of rumors was scuttled when Sinopec (the shorthand for China Petroleum & Chemical) denied that it was negotiating to buy all or part of Husky. Whether PetroChina was ever involved in talks is not clear.

What occurred during the flurry of speculation was that Husky shares, which had already gained 40 percent this year, climbed to a 52-week high of C$35.65, then took their biggest drop since 2002 when Sinopec issued its statement.

Among analysts there was a consensus that the Chinese lost interest. Faced with Husky’s market capitalization of more than C$14 billion, which would have made a deal the second largest in Canadian history next to the merger of PanCanadian Energy and Alberta Energy Co. to create Encana.

On top of that, a rapid climb in the value of the Canadian dollar against the Chinese currency provided a further disincentive.

But there is little doubt that Husky has all the elements the Chinese are looking for, including output of 325,000 barrels of oil equivalent per day, a 72.5 percent share of the 67,000 bpd expected from Newfoundland’s White Rose field by early 2006, up to 35,000 bpd from the Tucker oil sands project as early as late 2006 and plans for a 200,000 bpd Sunrise oil sands project. In addition, Husky owns a heavy oil upgrader that should soon have capacity of 82,000 bpd.

Husky’s reported interest in Enbridge plans for a possible 400,000 bpd pipeline from the oil sands to a deepwater port on the British Columbia coast opens the door to tanker shipments to Asia.

But Husky’s asset mix, including a chain of gasoline stations in Western Canada, could also be a deterrent. However, the betting is that rumors will continue to fly until Husky’s ownership changes hands and that could include deals for the component parts.

Wood Mackenzie report in, but nobody’s talking

WOOD MACKENZIE, WHICH ISSUED a 2002 study that ranked Alaska 15 out of 61 oil provinces when it came to profitability per barrel of oil for oil companies, has a new report out. But the results of the high-priced study are off-limits to everyone except those governments and companies that purchased them, including the Alaska Oil and Gas Division and the Alaska Legislature’s Budget and Audit Committee, chaired by Rep. Ralph Samuels, R-Anchorage.

Judy Brady, executive director of the Alaska Oil & Gas Association, and an aide in Samuels’ office told Petroleum News that they had to sign confidentiality agreements with Wood Mackenzie when the study results were released at the end of November and are currently working with the international research and consulting firm to determine when they can and can’t release the public.
Second of four BP double-hulled tankers goes into service

The second of four double-hulled tankers that are being built to carry Alaska crude to West Coast refineries was launched Dec. 4 at a naming ceremony at the San Diego shipyard where the new ships are being built. (See photo on page 1.)

The Alaskan Explorer got the traditional bottle of champagne smashed across its hull by Maureen Hayward. She’s the wife of Tony Hayward, group chief executive of exploration and production for BP. Sharon Marshall, spouse of BP Exploration (Alaska) President Steve Marshall, was her matron of honor in the ceremony.

The ship is virtually identical to the Alaskan Frontier, which went into service in August and has carried five cargos south so far. The 941-foot-long ships can hold 1.3 million barrels of crude, a little more than four days’ worth of BP’s North Slope production.

The Alaskan Explorer is expected to finish sea tests and start carrying oil south in January or February, according to Daren Beaudo of BP in Alaska.

The ships, built to last 50 years, are powered by twin diesel-electric systems in separate engine rooms, with two propellers and two rudders. They have a multitude of design features to improve reliability and reduce potential for spills.

The keel for the third ship was laid in July, and construction on the fourth ship started in October. They are being built by National Steel and Shipbuilding Co., a subsidiary of General Dynamics Corp. About a thousand workers are employed for the ships’ construction.

Once the four tankers are in service, expected to happen around the second quarter of 2006, they will carry all of BP’s Alaska oil production, Beaudo said.

BP owns the ships, but they are operated by Alaska Tanker Co. of Portland. BP has a 25 percent stake in that company.

— ALLEN BAKER

San Diego shipyard where the new ships are being built. (See photo on page 1.)

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— ALLEN BAKER
State of Alaska, AOGA differ on $60B estimate

By KRISTEN NELSON & KAY CASHMAN
Petroleum News Staff

The state does agree, he said, that new investment is needed. But how much? Dickinson said there is a new Wood Mackenzie study just out and the state’s understanding is that the study estimates investment costs at $10 a barrel. He said the division talked about maintaining production at a million barrels a day for 10 years, he said, which would be some 36 1/2 billion barrels a year, which “averages out to an investment of about $16.44 required for each barrel — and that of course includes the barrels that are coming out of Prudhoe Bay tomorrow, and those clearly don’t require a $16.44 investment.”

AOGA put out the $60 billion figure, he said, and the state had a hard time figuring out what it means. The association talked about maintaining production at a million barrels a day for 10 years, which he said would be some 36.5 billion barrels a year, which “averages out to an investment of about $16.44 required for each barrel — and that of course includes the barrels that are coming out of Prudhoe Bay tomorrow, and those clearly don’t require a $16.44 investment.”

An 11-year investment would be about $20 billion “and we think that about $14 billion capital investment is required. We put those two together, we come up with about $34 billion, instead of $60 billion.” (Alaska’s North Slope.)

The state’s forecast isn’t as high as a million barrels a day out into the future, Dickinson said, so what if you add the barrels to make it 1 million barrels a day for the next 10 years — even at AOGA’s $16.44 a barrel that adds about $5 billion. But it’s still only $40 billion.

AOGA started with DOR numbers.

When asked about the conflicting $34 billion and $60 billion numbers, Judy Brady, AOGA’s executive director, laughed and said “well, when the state needs to attract new investment at these levels it is going to be more useful to work together to figure out how to attract that investment rather than worrying about which forecast is right. If either one is close to right Alaska will need to be strongly competitive with all the other oil and gas provinces worldwide. We believe our forecast is pretty close to the mark — that’s what it is, a forecast. We relied on figures in DOR’s presentation to the Legislature last year. Start with DOR’s projections showing that the North Slope needs 2.3 billion barrels of production from new fields and heavy oil plus 1.8 billion barrels from declining fields over the next 10 years — just to keep production flat at one million barrels a day. We estimated that the average cost of a barrel of oil would be $15.00, using the 2002 Wood Mackenzie Alaska cost of $12.82 per barrel with an additional cost factor for the oil from new fields and heavy oil.”

Brady noted that environmental costs from the mature fields like Prudhoe and Kuparuk are increasing as well.

“When you multiple 4 billion by $15, the total is $60 billion. As to the Wood Mackenzie 2004 study, we also understand they use closer to a $10 per barrel price, apparently by not adding in the tanker costs. They also apparently included gas fields from Cook Inlet,” she said.

AOGA is reviewing the report now. “It would be wonderful if the cost for the 4 billion new barrels we need really was only $10 per barrel to produce. Unfortunately that just doesn’t pencil out in the real world of Alaska’s North Slope.”

OFFSHORE DEBATE REV'S UP

B.C. federal review panel finds 75 percent want no part of ending a 1972 moratorium; East Coast spill and oil project losers give B.C. activists more ammo against opening offshore

By GARY PARK
Petroleum News Calgary Correspondent

They’re not even remotely on the same scale as the Exxon Valdez spill and clean-up.

But the largest oil spill off Canada’s East Coast and the remnants of Nova Scotia’s first offshore oil project have rippled across thousands of miles to British Columbia.

About 1,000 barrels of crude spread over several miles offshore Newfoundland in late November after a malfunction at Petro-Canada’s Terra Nova platform, shutting down the 165,000 barrel/day operation. That coincided with a decision by the Canada-Nova Scotia Offshore Petroleum Board to seek public comments on whether debris left from the Cohasset-Panuke oil field, which pumped 30 million barrels during its short lifespan in the 1990s, should be cleaned up or ignored.

Regardless of the scope of those problems, which some have dismissed as overblown, and regardless of the fact that about 500 million barrels have been pumped in the stormy Newfoundland waters without any significant previous spill, these molehills are being turned into mountains by opponents of opening up the British Columbia offshore. They have also coincided with the findings of a public review panel headed by former National Energy Board chairman Roland Priddle’s admission that the 75 percent estimate was based on a “head-count,” because the volume and nature of the submissions did not allow for a more accurate estimate.

Mayors of two coastal communities who see an offshore industry as vital to their economic future described the panel’s findings as superficial and misleading.

Harry Mose, mayor of Port Hardy at the northern end of Vancouver Island, dismissed the findings as “useless,” while Prince Rupert Mayor Herb Pond said he was “very disappointed.”

Mose said lifting the ban was a key plank in his municipal re-election campaign and he got 79 percent of the vote, reflecting the pro-development sentiment in the Port Hardy area which could be a major staging point for exploration and development.

Pond said he has heard from hundreds of rural residents and First Nations’ people who favor lifting the moratorium, as long as tough regulations are imposed.

Review panel findings on minister’s desk

The review panel report findings went to Canada’s Natural Resources Minister John Efford, who will not comment until he has had the benefit of expert advice. However, he sided with the Campbell government’s pro-development stance. “They have a right to because of the economic opportunities,” he said.

A spokesman for B.C. Energy Minister Richard Neufeld said the ministerial cooperation to make an informed decision on opening up the offshore.

Brian Peckford, Newfoundland premier during the development of that province’s offshore and now a consultant on Vancouver Island, told the Financial Post that “one thing seems quite certain — there will be no real offshore activity for many, many years.”

If 75 percent of British Columbians “vote for governments that will work hard to do anything that contradicts the will of a substantial majority,” he said. Bill Wareham of the David Suzuki Foundation said the people of British Columbia clearly recognize that the risks of offshore drilling and exploration far outweigh the benefits.

If nothing else the East Coast setbacks have put a sharper edge on the looming showdown to determine whether British Columbia’s wealth will come from offshore oil and gas or whether its environment, fishery and tourism riches will get priority.●
Drilling rates soar on tight deepwater rig market

Transocean predicts shortage of fifth-generation floaters in '05, rig day rates to go higher

By RAY TYSON
Petroleum News Houston Correspondent

D ay rates for high-specification rigs capable of drilling in 10,000 feet of water have rocketed more than 40 percent since the first of the year and could increase as much as $240,000 per day as the supply of "ultra-deepwater" rigs begins to dry up next year.

In fact, the world's largest offshore driller, Transocean, is now expecting a global shortage of so-called fifth-genera-
tion units, or technologically advanced deepwater rigs constructed since the late 1990s.

The demand for high-spec rigs appears to be driven by unusually high levels of exploration and development drilling activity occurring at the same time, undoubtably supported by the strong commodity price environment.

"A lot of wells will be drilled in places like Angola, Nigeria and in deepwater Gulf of Mexico to bring some of this oil to the market," Jeff Chastain, Transocean's head of investor relations, said Dec. 1 at the Friedman Billings Ramsey annual investor conference in New York.

Just 24 fifth-generation rigs

There are just 24 fifth-generation rigs in the word today, with two new builds due out of the yard in mid-2005. Operators' preference for these rigs "is why we believe there will be a shortage" in 2005, Chastain said.

"You see operators today that are talking to us well in advance of these rigs being available, as much as eight months to a year before they are available," he added. "They're already discussing the time they want the rig when it does become available."

Two years ago long-term contracts for high-spec rigs were far and few between, Chastain said.

"Operators knew the rigs were there and they knew they could get them when they wanted them," he said. "So they are beginning to focus on the next level down."

Long-term contracts now the norm

But times have changed. Fifth-genera-
tion rigs that pulled $130,000 to $160,000 per day on the spot market at the begin-
ing of 2004 are now going on long-term contracts for $200,000 or more, he said.

"In fact, we've seen signings that have been anywhere from $200,000 up to as high as $240,000 a day," he said.

He said operators generally want long-term contracts of a year or more. In the U.S. Gulf, for example, BP has a three-year rig contract for field development at its huge Thunder Horse discovery in Mississippi Canyon. Last April BP got the rig for a bargain $183,000 per day.

"If that rig were signed in today's market... it probably would be somewhere in the $240,000 range," Chastain said.

"Timing is everything. And in the case of BP, their timing was very good."

He said fifth-generation rigs also are coveted by industry operating in waters of 7,000 feet or less because of "efficien-
cies" that reduce drilling time and there-
fore expenses related to drilling, such as supply boats and helicopters that ferry workers to and from rigs.

"You look at all that and add it up and they can save a lot of money on their drilling programs when they start looking at these fifth-generation rigs," Chastain said.

Study shows fifth-generation rigs faster

He said Transocean conducted an internal study showing that based on 5,000 feet of water and a target depth of 21,000 feet, the most advanced fifth-genera-
tion rig could finish a well in 38 days vs. 58 days for a fourth-generation rig and 63 days for a third-generation rig. Even a less advanced fifth-generation rig could do the job in 45 days, he noted.

Meanwhile, Gulf of Mexico day rates for lower end deepwater rigs capable of drilling in 4,500 to 7,000 feet of water have increased to around $150,000 per day from $80,000 to $90,000 per day at the start of this year, Chastain said.

"The reason is partly because that 7,000 foot and greater rig is really so tight now that a lot of these operators who had preferences have decided they can't get them, or they are not willing to pay the kind of number that would be required to get them," he said.

"So they are begin-
ing to focus on the next level down."

The U.S. Minerals Management Service expects deepwater drilling activi-
ty to continue strongly in the U.S. Gulf, based on its own calculations that 56 bil-
lion barrels of an estimated 71 billion bar-
rels of total oil equivalent reserves remain to be found in the region. Exploration drilling in 2002 and 2003 alone turned up more than 2 billion barrels of oil equiva-
lent with a dozen fields coming on stream in 2003 and another 13 planned in 2004.

"What can mitigate the tightness, or at least the rig shortage, is if an operator decides to postpone a project, which they may very well do, although that is a cost-
ly decision," Chastain said.

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● GULF OF MEXICO

Two years ago long-term contracts for high-spec rigs were far and few between... "Operators knew the rigs were there and they knew they could get them when they wanted them. There was no sense in tying them up for 12 months or longer." —Jeff Chastain, Transocean's head of investor relations
Governor wants roads to rev up economy '05

Murkowski's package includes roads to Point Thomson and the National Petroleum Reserve-Alaska; extended North Slope drilling season; exploration incentives for Bristol Bay area-wide sales leases; and $30 million for gas pipeline work

**By ROSE RAGSDALE**

**Petroleum News Contributing Writer**

Gov. Frank H. Murkowski’s aggressive plans to rev up resource development in 2005 may encounter opposition in the Alaska Legislature on both sides of the aisle unless he is careful to craft fiscally and environmentally conservative strategies for achieving his goals, lawmakers say.

Murkowski outlined his energy agenda at a news conference in Anchorage Dec. 3. He told reporters and Alaska labor leaders that he will ask the Legislature for $20 million to begin preliminary engineering for new and improved roads designed to enhance oil, gas and mining resource extraction opportunities on the North Slope and near the Red Dog Mine in Northwest Alaska.

Reiterating his commitment to create new jobs by building a sound economy in Alaska, the governor said roads are a key part of his energy agenda for 2005. His administration plans to begin engineering work on the 75-mile Foothills West Road, which will run from the Dalton Highway at TAPS Pump Station 2 west toward the National Petroleum Reserve-Alaska, to continue analysis of a 50- to 60-mile road from Prudhoe Bay east to the gas-rich Point Thomson and near the Red Dog Mine in Northwest Alaska.

ROADS TO REMOTE AREAS

**State of Alaska Department of Natural Resources Digital Oil and Gas Well Logs Request for Information**

The State of Alaska, Department of Natural Resources, is soliciting information for the purpose of determining the availability of existing digital well files from oil and gas wells drilled throughout the state prior to 1986. The log data must be in Log Analysis Standard (LAS) format. All of the data obtained will be provided to the Alaska Oil and Gas Conservation Commission (OGGCO) who, as the permitting agency and repository for such data, is required to make non-confidential portions of such data available to the public. The State does not require exclusive rights to the data.

If you have any of this data and are interested in either selling it or otherwise providing it to the State of Alaska, please respond in writing by Feb. 30, P.M., AST, on December 19, 2004, to Jim Cowan, State of Alaska, Department of Oil and Gas, 560 W 7th Ave, Suite 800, Anchorage, AK 99501-3650, fax 907-269-8238. Responses may be hand delivered, mailed, or faxed. Responses must provide answers to the following:

1. Do you have any of the data described above? 2. Do you have LAS format? 3. Are you willing to provide it to the State under the conditions expressed above? 4. Do you require compensation for the data or are you able to donate it?

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**Judy Brady, executive director of the Alaska Oil & Gas Association, said allowing the industry to gain access to exploration sites as much as three weeks earlier will bring immediate benefits to the state and is a very important step in keeping Alaska’s oil patch competitive with other places in the world.**

Other provisions of the governor's energy agenda include seeking legislative approval to extend to 2003 a $20 million road package for the North Slope and gas leases in Bristol Bay. The previous legislation opened an exploration incentive window of four years for oil and gas development that companies could use to reduce their state severance taxes.

Bristol Bay area-wide sale

The state is due to conduct an area-wide oil and gas lease sale on the Alaska Peninsula near Bristol Bay by spring 2006, which would not give companies adequate time to take advantage of the incentive program, according to state planners. So the governor will ask the Legislature to extend the window of eligibility until 2010 for the Alaska Peninsula lease area.

Though oil companies have been pretty low-key about the proposed sale, Brady said the industry is intrigued by the idea of the state opening new areas to leasing. “It’s something we’ve always supported because we are in the business of exploring for oil and gas,” she said. “It’s an effort to open up areas to the oil and gas industry that we think have the potential for significant discovery.”

The funding request will be made to the Legislature Dec. 15. But Murkowski said there would be a delay in submitting the request because it would not be possible to extend the winter season in a study that took a year to complete, Brady said.

**Approval depends on plans to fund**

Whether the Republican-majority Legislature approves Murkowski’s $20 million road package will depend on how he plans to fund it, said Sen. Tom Wagoner, R-Kenai, who chairs the state Senate Resources Committee. “Sen. Lynn Hoffman, R-Anchorage, said it best when he described the Legislature as a ‘tight-fisted bunch;’ he said in a telephone interview Dec. 3. If Murkowski seeks a direct appropriation from state coffers he may encounter trouble from the fiscally conservative majority, Wagoner said. “We’re not too much in favor of that because the average Alaskan doesn’t spend a lot of time driving around the North Slope,” Wagoner said. Rep. Eric Croft, D-Anchorage also questioned the wisdom of spending state funds on North Slope roads.

“The $20 million did seem a little steep,” he said Dec. 6. “I’d rather spend $20 million on a pioneer road beyond Lake Otis Parkway and Tudor Road to somewhere. In other words, I’d try to spend some of that money on roads to people.”

If Murkowski proposes to sell bonds to fund the roads package, especially bonds that the oil companies might pay back as they use the roads, Wagoner said the Legislature would likely go along with the plan.

Roads to remote areas of the state, including the North Slope, will be very important to Alaska’s economy in the long run, Brady said.

Judy Brady, executive director of the Alaska Oil & Gas Association, said allowing the industry to gain access to exploration sites as much as three weeks earlier will bring immediate benefits to the state and is a very important step in keeping Alaska’s oil patch competitive with other places in the world.
Burlington goes with ‘modest’ $2B budget in ’05

By RAY TYSON
Petroleum News Houston Correspondent

Natural gas producer Burlington Resources, sitting on a pile of cash pocketed from the run up in commodity prices, is planning a modest 11 percent increase in capital spending next year, a portion of which is earmarked just to cover anticipated increases in oilfield service costs.

The big exploration and production independent said Dec. 8 that it intends to spend about $2 billion in 2005 vs. $1.8 billion in 2004.

“Our base capital program, adjusted for the service cost and currency exchange impacts, is up only modestly,” conceded Bobby Shackouls, Burlington’s chief executive officer. He said the rising strength of the Canadian dollar is particularly troublesome.

In part, the 2005 budget reflects Burlington’s commitment “to invest consistently throughout price cycles, which we believe is essential for maintaining our efficiency,” Shackouls said.

EIA drops WTI projected 4Q average to $49 per barrel

Agency expects price to remain in mid-$40s through 2005 based on low inventories, limited prospects for large production increases outside of OPEC

The U.S. Department of Energy’s Energy Information Administration said Dec. 7 that it has lowered its projected fourth quarter average for West Texas Intermediate spot prices after “WTI prices eased sharply in November.”

U.S. spot prices for WTI crude oil have ranged about $18 per barrel higher than in the fourth quarter of 2004 “as global economic growth for 2004 “has been revised downwards slightly” to 2.6 million bpd above 2003 levels, still “strong 5.1 percent growth for the year.”

Global oil demand is expected to slow to 2 million bpd, a 2.5 percent growth rate, in 2005 “as global economic growth slows toward more sustainable rates, influenced in part by high world oil prices.”
**COLORADO**

**Berry buys gas properties in Colorado**

Berry Petroleum Co. is paying $110 million for interests in northeastern Colorado natural gas fields, the company said Dec. 6. The sellers are J-W Operating Co. and others. Berry, based in Bakersfield, Calif., will acquire interests in more than 130,000 acres in the Niobrara fields. The purchase provides Berry with 9 million cubic feet of gas production daily from an area with estimated proved reserves of 87 billion cubic feet. Berry will have a 52 percent working interest and will be operator of the fields. The company plans to spend $4 million to $8 million next year in capital investments there. Berry expects to boost production by more than 15 percent a year over the next four years through infill drilling that will bring spacing to 40 acres per well, according to Robert F. Heineman, the company's president and CEO. Effective date of the transaction is Nov. 1, with closing expected in the first quarter of next year. The purchase is being financed by borrowings under Berry's existing credit facility.

**SNYDER, TEXAS**

**Patterson-UTI acquires Key Energy’s drilling assets for $62 million**

Onshore drilling contractor Patterson-UTI says it has agreed to purchase the U.S. land drilling assets of Key Energy Services for $62 million. The deal includes 25 active drilling rigs in the Permian and San Juan basins and the Rocky Mountains, as well as 16 rigs that are currently stacked, Patterson said Dec. 8. Also included in the transaction are related drilling equipment and a rig moving fleet consisting of about 45 trucks and 100 trailers. The active rigs are mechanical with an average of about 700 horsepower and depth ratings of around 10,000 feet.

Patterson, based in Snyder, Texas, currently owns 361 land-based drilling rigs that operate primarily in Texas, New Mexico, Oklahoma, Louisiana, Mississippi, Colorado, Utah, Wyoming and western Canada.

Key Energy said it will incur a yet unspecified loss on the sale of its assets to Patterson. Key Energy, based in Midland, Texas, provides energy operations including well servicing, contract drilling, pressure pumping, fishing and rental tool services and other oilfield services. The company has operations in all major onshore oil and gas producing regions of the continental United States and internationally in Argentina and Egypt.

**BURLINGTON**

**Williston basin, the company said.**

Twelve percent of next year’s capital is allocated to the international sector. Eighty-five percent of next year’s capital budget is allocated to development and extension projects, and 15 percent to exploration, Burlington said.

Burlington’s board of directors, for the third time since late 2000, restored a $1 billion share repurchase authorization. Since 2000, the company has repurchased 60.6 million shares, nearly 15 percent of its total shares outstanding.

“It supplements our dividend while serving as a value play for the company, since we are in effect repurchasing reserves in the ground at prices lower than the industry’s average replacement costs, and lower than the equivalent cost of acquisitions we’ve seen in the marketplace this year,” said Steve Shapiro, Burlington’s chief financial officer.

Burlington said it expects to finance both the capital investment and share repurchase programs from cash flow. The company also estimates that during 2004 it will replace more than 115 percent of its production with new reserves.

**Stone Energy budgets $313M**

Meanwhile, Louisiana-based independent Stone Energy said its board of directors has approved a 2005 capital spending budget of $315 million, excluding any possible acquisitions.

The company said it expects to spend about 15 percent of its budget on exploration drilling in the deepwater Gulf of Mexico, while about 50 percent is earmarked for conventional exploratory and development operations on the Gulf’s continental shelf.

20 percent for deep gas drilling on the shelf and 15 percent for the Rocky Mountains.

**EIA**

Chinese oil demand growth is also expected to moderate from its 2004 rate, “which reflected a dramatic increase in demand for oil-generated power that is not likely to be repeated,” the agency said.

**Near-term price expected to remain in mid-$40s**

The agency said because strong oil demand growth in 2004 is expected to continue into 2005, inventories in industrialized countries remain relatively low. The lower inventories, and limited prospects for large oil production increases outside OPEC in the near term, “suggest that oil prices will remain in the mid-$40s range through 2005, even though OPEC crude oil production remains high at about 30 million barrels per day.”

Production capacity remains at about 580,000 to 1 million barrels per day “above current output levels, implying a global utilization rate of about 99 percent,” the agency said.

The United States is expected to see an increase in oil production in 2005 of about 160,000 barrels per day, “something that has not happened on an annual basis since 1991,” the agency said. The increase is partly due to continued recovery from Hurricane Ivan, but also to rising production in federal U.S. Gulf of Mexico waters.

**Henry Hub to average $6.03 per mcf in 2004**

The agency said Henry Hub prices are expected to average $6.03 per mcf in 2004, up from $5.64 in 2003, and to hold at level about $6.01 per mcf in 2005. “These prices are lower than last month due to continued high natural gas inventories.” Working gas in storage is estimated to have reached 3.280 trillion cubic feet at the end of November, the agency said, 8 percent higher than a year ago and 11 percent higher than the five-year average.

The average Henry Hub natural gas spot price was $5.15 per mcf in September and $6.54 per mcf in October, but as Gulf of Mexico production recovered and November weather remained mild, spot prices dropped below $5 per mcf Nov. 19. With peak winter weather closing in, the agency said, natural gas prices are expected to rise over the next several months.

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The Cook Inlet gas play from the perspective of a small independent working in Alaska

by ANDY CLIFFORD
Special for Petroleum News

In a previous article (see Oct. 17 issue of Petroleum News) Aurora Gas shared its thoughts regarding the Lower Tyonek and Herrick oil play. Aurora is just beginning to mature its exciting inventory of onshore oil prospects with drilling expected to begin in 2005. In this article, Aurora is focusing on the shallow gas play, which it has successfully exploited in the last four years with established gas production in four separate fields, Kaloa, Lone Creek, Moquawkie, and Nicolai Creek, all on the west side of Cook Inlet.

The Cook Inlet sedimentary basin of Alaska covers an area of approximately 12,000 square miles. A cumulative total of almost 1.3 billion barrels of oil and 7 trillion cubic feet of gas have been produced in the basin since the first discovery was made at Swanson River in 1957. Most of the exploratory drilling in the basin was undertaken prior to 1968, when larger reserves were discovered on the North Slope of Alaska and industry’s attention and technology focused to the north. Nearly 90 percent of the present reserve base was discovered in that early phase of drilling.

Thermogenic gas in-place for Cook Inlet has been estimated at 3.1 tcf. A further 7.5 tcf of biogenic gas reserves have been estimated to be present. Cook Inlet non-associated gas occurs within the Sterling, Beluga and Tyonek formations in a mixture of biogenic “swamp” methane and gas from low grade bituminous coal degasification formed and trapped in situ in nearby channel sands. Such gas is formed independent of the deep thermogenic gas associated with the oil fields. The gas to gas for all formations is approximately 0.56.

The Tyonek gas sands are generally more productive than the Beluga sands but less than those of the Sterling formation. The majority of the Sterling gas fields have exceptionally good rock quality with the formation’s thick, blocky sands. Aurora’s gas fields produce gas from Beluga and Tyonek reservoirs.

Aurora believes there isn’t enough exploration.

There is no shortage of gas in Cook Inlet, or rather there should not be a shortage of gas. In Aurora’s opinion, there is plenty of gas yet to be discovered in the basin but there are not enough exploration dollars being spent, nor enough companies exploring the basin’s potential. There are several reasons for this.

There is a perception in industry that the remaining gas potential in Cook Inlet is limited due to a lack of appreciable exploration success in recent times.

Good quality seismic data is scarce to non-existent over large tracts of the basin and is generally limited to 2D seismic, much of which was acquired prior to the 1990s. The geology is complex both structurally and stratigraphically. The steeply dipping flanks of the wrench-induced antclinal folds are poorly imaged on seismic data and the prospective non-marine sands have limited areal extent and are also poorly imaged because of the numerous interbedded coals that “mask” the sands.

Log analysis in Cook Inlet is particularly difficult since commonly used techniques such as neutron-density crossover only work for thicker, cleaner sands such as those in the Sterling and parts of the Tyonek formations. Most gas pay in Cook Inlet has to be interpreted using a combination of log curves. Many of the old wells in the basin only have a sonic log for porosity estimation. In addition, reserve estimation is very difficult, especially without the benefit of multiple wells and good pressure data.

Costs of Cook Inlet exploration high.

The costs of exploration in Cook Inlet are very high compared to areas in the Lower 48. Most seismic acquisition requires the use of heliportable drilling, which is expensive, and operations on the west side of the inlet require the use of barges, planes, landing zones, staging camps and portable satellite communication towers. Development of shallow, low-pressure gas reservoirs such as those at Aurora’s Kaloa, Lone Creek, Moquawkie and Nicolai Creek fields, where productive depths range from 1,300-3,500 feet, require the use of compression and dehydration facilities on the surface and gravel packs and sand screens in the subsurface to prevent sand production from the loose, unconsolidated reservoirs. Such procedures are expensive and mechanical surface equipment is subject to occasional failures.

Aurora believes remaining gas potential ‘outstanding’.

Aurora believes the remaining potential for discoveries of non-associated biogenic gas in Cook Inlet is outstanding. There have been some excellent recent successes by Marathon and Unocal at Ninkchik and Happy Valley showing there are fields of 50-100 billion cubic feet still to be found in Cook Inlet. It is worth noting, however, that both of these successes were spurred by pre-existing wells at Falls Creek and Happy Valley with tested gas or bypassed gas pay recognized on logs. The early successes were then expanded into other areas on trend. Aurora has identified a multitude of bypassed gas opportunities throughout the basin in old wells drilled for deeper oil objectives as well as new play types without productive analogs in the basin. Two specific examples of these are Aurora’s Three Mile Creek and Long Lake prospects. The former prospect, where Aurora is currently drilling the Three Mile Creek Unit-1 well, is targeting Beluga and Tyonek gas reservoirs updip from the Superior Three Mile Creek-1 well, drilled in 1967. The structure is a four-way anticline located in the footwall of the Moquawkie Anticline, which lies to the west. Aurora recently completed pre-stack depth imaging of newly acquired 2D seismic data over the prospect. The Long Lake area is one where Aurora is pursuing Tyonek-aged alluvial fan deposits with gas trapped against basement granodiorites that
Aurora re-evaluated the 1973 Texaco Long Lake Unit-1 well with a re-entry of the well and new logging during 2004 and plans a follow up well in early 2005.

**Existing seismic expensive to license**

Existing seismic data is expensive to license (typically $1,000-2,500 per mile), invariably of poor quality and difficult to license in some areas because of confusion surrounding ownership of the data plus a lack of incentive for some companies to license data. New acquisition costs can run as high as $25,000 per mile for 2D and $100,000 per square mile for 3D. Aurora recently helped usher in the use of mulchers for seismic acquisition, a technological application commonly used in Canada and parts of the Lower 48 for “minimal impact” seismic, with a cost reduction of about 10-15 percent. The cost of seismic processing has dropped dramatically of late and Aurora has taken advantage of this by doing reprocessing of existing seismic, both 2D and 3D. One of their 3D surveys has undergone several reiterations in the last 12-18 months. Illumination studies, ray-tracing and model building can help determine the necessary line length and offset needed during seismic acquisition. The extra cost of adding more shot holes to lines to adequately image the deep structure has been a deterrent to companies. Furthermore, because the objective of older seismic acquisition was often deeper oil targets, there was very little common depth point fold in the shallower gas-prone section. Getting adequate high fold in the latter requires a denser grid of shot holes, which are expensive.

**Complex geology includes structural inversion**

The complex geology can be better understood by studying analogs from other basins and from within Cook Inlet itself. The west side of Cook Inlet shows strong evidence of structural inversion. Ongoing studies by Aurora at Moquawkie and Nicolai Creek using recently acquired 3D seismic data suggest that the existing anticlines were once structural lows, as evidenced by isopach mapping of discrete intervals. These structural lows acted as a focusing mechanism for anastomosing fluvial channels prior to uplift and inversion in the Plio-Pleistocene.

One of the first things Aurora ever did when entering the Cook Inlet gas play was to study existing fields such as Kenai and Beluga River and in particular the log responses within those fields to gas sands and wet sands. They made a catalog of log responses for each formation and have subsequently updated it. Aurora has also undertaken substantial log analysis of gas sands and wet sands from existing fields as calibration wells for their prospects. They have also compiled an inventory of seismic characteristics of existing gas pay, including seismic “gas chimney” effects and direct hydrocarbon indicators.

Aurora acquired two 3D surveys over Moquawkie and Nicolai Creek fields in 2003 and has experimented with a revolutionary amplitude vs. offset (AVO) technique that helps differentiate coals (which have a unique AVO signature), gas sands and wet sands. Just as with log interpretation, where the first step is to recognize the coal signature, the coals can be “blackened” out, leaving a seismic dataset with just gas sands, wet sands and shales, each having unique seismic characteristics. Then by time-slicing at various flattened seismic horizons that correlate to gas pay or wet sands in wells within the dataset, Aurora can start to map individual sand body geometries such as fluvial channels within the Beluga and Tyonek sands. By testing this hypothesis in 2003 by targetting one of the problems in Cook Inlet, not being able to differentiate stratigraphy, Aurora immediately helped to demarcate stacked AVO anomalies in a stratigraphic trap setting in what might be a first for Cook Inlet exploration!

**Log analysis presents challenges**

Gas sands are typically detected by using neutron-density logs. Whereas for clean, normally pressured sands, the presence of gas is evident wherever crossover of the neutron porosity and density porosity logs occurs, this is not always the case in Cook Inlet. Log analysis in Cook Inlet is particularly challenging, especially with respect to the gas pay. While the crossover method utilizing neutron and density logs usually works quite well in clean formations, or those without heavy mineral particles, it provides very pessimistic results for deposits such as the Beluga formation. In general, the natural presence of gas will cause a shift in the density porosity readings to higher values while the neutron porosity readings will be lower than the density readings. A commonly used technique in Cook Inlet is to make a shift of 12 porosity units when overlaying the neutron and density logs. Another commonly used technique is Schlumberger’s Elements Log Analysis, “ELAN,” which uses a software model designed specifically for Cook Inlet. It provides readings for the amount of bound water in the formation, the amount of gas present and amount of moved gas. Aurora makes extensive use of log analysis by NuTech Energy, who run conventional digital log data through a three-step process for editing, normalizing and correction of any calibration errors then model the response to provide new irreducible water saturation or BVI outputs and finally produce a simulated nuclear magnetic resonance or NMR log. The multi-track output they provide includes permeability, volumetrics, lithology, clay volume displays and two flag tracks. NuTech has helped Aurora identify bypassed gas pay in Cook Inlet. The crossover method works in cleaner, thicker sands such as the Sterling formation. Very rarely, neutron-density crossover is seen in Beluga sands, but they are usually too thin or too shaley. Tyonek sands can exhibit crossover in thinder, cleaner sands but otherwise resemble the Beluga interval.

Cycle skipping on the sonic log is also generally a good indicator of gas pay, especially in the cleaner Sterling and Tyonek sands. Formation resistivity for proven gas pay varies greatly throughout Cook Inlet but deep resistivity should generally read more than 20 ohms, although there are notable examples, especially within the Tyonek where resistivity is as low as 13-14 ohms for wells that have produced more than 15 bcf of gas. However, in such rare cases there is usually a good mud log show even if neutron-density crossover is lacking.

**Recognition of gas-water contact important**

While log analysis poses particular challenges in identifying gas pay to begin with, further evaluation of a gas reserve is difficult without recognition of a gas-water contact. Such contacts are readily seen in Sterling sands and thicker Tyonek intervals, such as the Grayling gas sands of McArthur River field. Volumetric analysis for the Beluga and
continued from page 10

**PROSPECT**

Tyonek formations is extremely difficult since location of gas-water contacts are hard to delineate. In many cases there might not be a true, distinct gas-water contact at all but rather a large transition zone between water saturations of 30-40 percent in the gas leg and 60-70 percent in the water leg.

There appears to be a lot of “fizz” gas or low saturation gas, probably caused by commingling gas recharge from the interbedded coal beds.

By far the most challenging problem facing log analysts and petrophysicists working Cook Inlet is correct calculation of water resistivity. Variations in formation water resistivities are believed to be the main cause of water saturation cutoff variation between wells. Water resistivities calculated from the SP, spontaneous potential, curve are possibly not valid because of SP reductions related to shaliness effects and hydrocarbons.

Other problems affecting volumetric reserve estimation include: (1) the lack of stratigraphic definition on seismic data; (2) the presence of seismic gas chimneys; (3) low seismic fold at shallow depths; and (4) poor seismic resolution at depth due to energy absorption by the coals and generation of interbed multiples by the coals.

Gas reserve estimation is best accomplished by material balance, supplemented by decline analysis, where pressure data is sparse, and finally volumetrics. Extended well tests with about 300 million cubic feet of gas production are usually sufficient to give a good estimation of recoverable reserves. Many wells in Cook Inlet have commingled completions making it difficult to allocate production from existing fields to individual sands within any given field. Furthermore, net pay thicknesses and reservoir parameters vary greatly for gas reservoirs in Cook Inlet.

**High exploration and operating costs due to low activity levels**

There is very little that can be done to reduce exploration costs in Cook Inlet. Because there is such little activity with few players, there is a limited number of contractors, a limited number of rigs, no offshore rigs and a limited supply of technology (both logging, completion and seismic). There is also a restricted operating season for some activities.

Aurora wanted to acquire multi-component 3D seismic to use shear data to better see through the “gas clouds” over some of their fields but the equipment was prohibitively expensive to bring in. Operation costs can be reduced by the concept of area wide development with initial wells bearing the brunt of expensive gas gathering pipelines and facilities with subsequent wells being more economic because of short tie ins and shared operational support. Multi-well drilling/completion programs can benefit from the bundling of contractor services.

Aurora has developed gas reservoirs shallower than anyone else in Cook Inlet. Unfortunately, such reservoirs are low pressured and require sand control as well as compression in order to meet pipeline specifications.

**Recovery averages 85 bcf per well for Sterling sands**

The discontinuous areal extent of such Beluga and Tyonek sands means that more wells are required for development. The Sterling sands are the most prolific in Cook Inlet with producing depths ranging from 3,300 feet-5,200 feet. Recoverable reserves range from 1.9 bcf per well at Beaver Creek to 216 bcf per well at North Cook Inlet, with an average of 85 bcf per well. The field decline rate for Sterling fields ranges from 7-20 percent with an average of 10 percent. The Beluga sands have porosities ranging from 10-22 percent and producing depths of less than 1,380 feet to 8,100 feet.

Aurora has established the shallowest Beluga production yet in Cook Inlet at its Nicolai Creek Unit No. 9 well, where the shallowest production is from less than 1,380 feet. Recoverable reserves range from 4.5 bcf per well at Lewis River to 18 bcf per well at Kenai with an average of 13 bcf per well. The decline rate for Beluga fields ranges from 14-36 percent with an average of 17 percent.

The Tyonek reservoirs generally exhibit porosities of 19-22 percent with producing porosities of 17,000 feet to 9,000 feet. Recoverable reserves range from 0.5 bcf per well at Granite Point to 90 bcf per well at McArthur River with an average of 56 bcf per well. The average decline rate for Tyonek fields ranges from 14-25 percent.

The shallower gas reservoirs are generally unconsolidated making core very difficult and most conventional and sidewall coring to date has been focused on the deeper oil and gas reservoirs. Water saturations for proven gas accumulations range from 35-50 percent with recovery efficiencies reaching as high as 90 percent.

Gas reserves per well depends on a number of factors including the lateral extent of sands, contributions from coal beds, the number of productive sands but also on depth and pressure. Test rates for Tyonek sands generally average 5-10 million cubic feet per day with some higher initial rates in some McArthur River wells.

Recoveries for the respective formations range from 960-1,240 thousand cubic feet per acre-foot for Sterling sands, 600-1,150 mcfd per acre-foot for Beluga sands and 490-1,150 mcfd per acre-foot for Tyonek sands.

To date, Aurora has constructed five gas gathering pipelines. One of these, connecting the three wells at the southern end of Nicolai Creek to the Cook Inlet Gas Gathering System, required the tunneling of a section from the top of the bluff near the Granite Point Tank Farm under the adjacent wetlands to the beach. The Lone Creek and Moquawkie fields have longer pipelines of five to six miles each, which will substantially enhance the economics of future developments in the vicinity of each field. Future development prospects will also be able to benefit from sharing of surface facilities.

**Gas marketing presents challenges**

Gas is a very different commodity from oil and the gas market in Southcentral Alaska is a “closed” market without access to Lower 48 markets. Several large fields such as McArthur River (Graying Gas Sands), Kenai, Beluga River and North Cook Inlet, have dominated Cook Inlet gas production for decades. Producers and utilities alike have “entrenched” positions and it is difficult for new producers in the basin to gain access to key infrastructure since the pipelines do not have open access as “common carriers.”

In addition, there is considerable uncertainty in the gas market with the possibility of future closures of both the Agrimex fertilizer plant and the liquefied natural gas facility, thereby changing the entire market dynamic.

Aurora Gas recently brought its fourth gas field on stream with the successful tie-in of the Kalua-2 well. Exploration drilling has begun at the Three Mile Creek Prospect and Aurora plans a full year of drilling activity for 2005 and is excited by the under-explored gas potential in the basin.

**Editor’s note:** Andy Clifford is vice president of exploration for Aurora Gas LLC.

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**History Repeats Itself.**

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**NORTHWEST TERRITORIES**

Interveners unhappy with Mackenzie funding

Government environment agencies have granted C$380,000 to 19 non-government organizations planning to intervene in the Mackenzie Gas Project hearings — only one tenth of what 36 groups had sought.

The Canadian Arctic Resources Committee made a joint request with the World Wildlife Fund and the Sierra Club of Canada for almost C$80,000 and ended up with only C$15,000.

Arctic committee spokeswoman Sheila Montgomery told the Canadian Broadcasting Corp. that the funding is inadequate to review thousands of pages of technical information that comprise the environmental impact statement.

She said that decision by the Canadian Environmental Assessment Agency and the Mackenzie Valley Environmental Impact Review Board will not allow “meaningful public participation” in the technical conferences.

A spokeswoman for Alternatives North said independent groups will not be able to focus seriously on the affect the project.

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**KENAI PENINSULA**

**Beaver Creek field shut in following Kenai Peninsula fire**

Marathon Oil Co. and state officials are investigating the cause of a Nov. 30 fire which destroyed two storage tanks and a well house and caused a gas leak at Marathon’s Beaver Creek A-1 well on the Kenai Peninsula in Southcentral Alaska Nov. 30. The Beaver Creek field is shut down as a result of the fire.

The tanks stored produced water and natural gas condensate, fluids which Marathon believes were contained by berms on the A-1 pad, the Alaska Department of Environmental Conservation’s Division of Spill Prevention and Response said in a report on the incident.

The division said the Kenai Fire Department responded to the fire which began at 5 a.m. Nov. 30 and had it extinguished at 8 p.m. The division said there were no injuries but there was extensive equipment damage.

Houston-based Marathon spokeswoman Susan Richardson told Petroleum News that equipment at the pad will need to be removed and replaced before production can be resumed.

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**BRITISH COLUMBIA**

**Anadarko blazes new trail in northeastern B.C.**

A

Marathon’s Beaver Creek transportation project under Buckinghorse River to develop 200 bcf of natural gas

Anadarko has made a technological breakthrough in northeastern British Columbia by completing a transportation project under the Buckinghorse River to develop a potential 200 billion cubic feet of natural gas.

Mike Bridges, president of Anadarko’s Canadian unit, said the project has demonstrated “how we can access areas that were previously considered uneconomic because they were too expensive or difficult to develop.”

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**ANCHORAGE**

Potential shippers, builders, comment on FERC’s regs

When Congress passed the Alaska Natural Gas Pipeline Act in October, it gave the Federal Energy Regulatory Commission 120 days to establish regulations for an open season for an Alaska gas pipeline. At a technical conference in Anchorage Dec. 3, FERC Chairman Pat Wood and commissioners Nora Brownell, Joseph Kelliher and Suedeen Kelly convened for the first time in Alaska to hear comments on proposed regulations, which include advance public notice of at least 30 days for an open season, information about a proposed project that any notice of an open season must contain and an open season length of 90 days.

(See related story on page 1.)

Edwin Holden, FERC staff counsel, said comments the commission received before the technical conference included a concern that producers will monopolize

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**REGULATIONS**
REGULATIONS

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pipeline capacity. While the commission has no regulations on open season, Holden said its policy is for a non-discriminatory open season. Congress specified that regulations be put in place for an open season for the Alaska gas pipeline, he said, because of long lead times, environmental concerns and the unique competitive situation.

TransCanada recommends rolled-in rates

Tony Palmer, vice president of Alaska business unit leader for TransCanada PipeLines, said TransCanada is working with the state of Alaska to finalize its right of way for the Alaska portion of a gas pipeline, and expects a final decision in the first quarter of 2005. TransCanada is one of two parties negotiating a fiscal contract with Alaska for a gas pipeline from the North Slope.

Palmer was the first of many expressing a concern with wording in the proposed regulations describing information that must be made available for an open season. In addition to specific items, the regulation says “all other information that may be relevant.” TransCanada was involved in the original gas pipeline proposal, he said, and has 27 years of data, much of it confidential and very little relevant to an open season today, and would like to see more specific language in the final regulations.

Palmer said TransCanada believes presubscriptions may be necessary to attract capital, such as the use of anchor shippers in the Gulf of Mexico. Anchor shippers should be allowed, he said, as long as other shippers are not disadvantaged.

On expansion he said the commission should send an “early signal” that it will be open to rolled-in rates to avoid different rates for similar service, and noted that the National Energy Board of Canada uses rolled-in rates. Rolled-in tariffs include expansion costs with original and shippers pay the same rate; in incremental pricing, those who need expansion capacity pay for it.

ExxonMobile: regulations need to be clear

Richard Guerrant, vice president of gas marketing for the Americas for ExxonMobile Gas, told the commission the “all other information” language is “problematic and unnecessary,” as some information could be proprietary.

He said anchor shippers may not be necessary, but banning anchor shippers could hurt the project.

On the expansion issue, Guerrant said ExxonMobile believes existing industry practices for expansion are adequate, especially since the commission can require expansion, an authority which is unique to the Alaska project, providing a “safety net if needed.” But, he said in response to a question from Wood, before we accept a certificate we’d like to know what expansion looks like.

He noted that the National Energy Board of Canada’s rolled-in rates policy was contentious when developed, so to say it’s good for Canada and it would be good for us is not accurate.

In response to a question from Kelliher on incremental vs. rolled-in rates, Guerrant said the only downside to reserves is the risks are with reserves which are not proven and the concern is that we don’t oversize the pipeline.

Guerrant told Wood industry knows it needs to study Alaska needs, it’s in the statute, but it is, he said, a “cart before the horse” issue. We’ll work with the state to see what the needs are and where drop-off points need to be, so everyone knows what the deal is.

But, he said, the real demand won’t be known until the bids are on the table.

BP supports non-discriminatory access

Ken Konrad, BP Exploration (Alaska)’s gas business unit leader, told the commission “more Alaska customers would be good news.”

BP: supports non-discriminatory access

Ken Konrad, BP Exploration (Alaska)’s gas business unit leader, told the commission “more Alaska customers would be good news,” but asked the commission not to burden the project with expansion regulations not required in this rule. Expansion issues, he said, should be determined at the time of expansion. “To address it now would be premature,” he said.

In response to Wood’s question on the in-state study, Konrad said the companies are in discussions with the state now and two or three tie-in points have been identified. The best study, he said, is the open season itself.

In response to a question from Brownell on the presubscription issue Konrad said “volume is good,” reducing the unit cost of transportation. We can design any size pipe that’s needed, he said, and anybody who wants to come aboard can. Any credit-worthiness shipper can become an anchor shipper.

In response to Kelliher’s question on rolled-in vs. incremental rates, Konrad said the concern is with risk: we take the risk and then our rates go up due to actions of others. There is an “inefficient” expansion in the future, he said, we get to pay for it.

The FEC’s existing (incremental pricing) policy is good, he said. If rolled-in rates are mandated for an expansion, and FEC approves an inefficient expansion, shippers would pay (through higher tariffs), he said in response to a question from Kelly.

ConocoPhillips: challenges remain

Joe Marushack, vice president of ANS gas development for ConocoPhillips Alaska, said the FERC’s proposed regulations are “reasonably balanced,” but said the “all other information” language is “too indefinite and overbroad.” For instance, he said, shippers may want to make some disclosures to the pipeline prior to an open season which could then be available to all shippers.

Marushack said ConocoPhillips does not think rates should be treated in open season regulations, because at this point no one has sufficient information. The goal here, he said, “should be to create certainty but allow flexibility.” The fundamental issue, he said, is a healthy, competitive environment on the North Slope.

FERC can mandate expansion, but expansion rules are not required in this rule making and rates should not be addressed here, he said. Rolled-in rates, Marushack said, would conflict with existing FERC policy, and could make voluntary expansion much more contentious and add to uncertainties.

In response to Brownell’s question on presubscription, Marushack said the anchor shipper concept is a win-win. The underlying volumes of gas are huge, and you’d know from presubscription about what size the pipe should be. Then you do an open season and design for what’s actually subscribed, so those exploring have additional time to find gas.

Enbridge: Binding agreements critical

Ron Brintnell, Enbridge Energy project director for Alaska gas, told the commission that binding agreements are critical and the commission should allow them as soon as possible. And, he said, a range of all pipeline sizes and rates should be allowed.

He said Enbridge believes FERC oversight should begin when an application is filed, but noted the Alaska pipeline has had unprecedented transparency, and said FERC rules shouldn’t result in misalignment with the Canadian portion of the line.

As for studies, the open season will reveal market needs, he said.

On the issue of rolled-in rates, Brintnell said certainty is important; anyone who might step up would want some certainty. He said Enbridge believes a negotiated rate is most likely.

Anadarko: pipeline will be a monopoly

Mark Hanley, Alaska public affairs manager for Anadarko Petroleum, said it is Anadarko’s view that “there’s no competition, it’s a monopoly” situation for an Alaska gas pipeline — and it should be regulated as a monopoly.

“We’re concerned about the monopoly being controlled by our competitors on the exploration side,” he said.

On the open season regulations, Hanley said the issue is not only the duration of the open season, “but when it occurs.” If the open season is in 2005, he said, there won’t be any local bidders or explorers participating. We need as late an open season as possible, he said.

And, he said, only if an open season for expansion capacity is for gas outside of Prudhoe Bay and Point Thomson would Anadarko feel comfortable that it would have an opportunity for expansion capacity.

Dave Anderson with Anadarko International Energy told the commission Anadarko believes a rolled-in tariff for expansion capacity is essential to promote development of North Slope gas.

Without rolled-in rates, he said, the pipeline would never be expanded beyond the 6 billion cubic feet per day possible with additional compression. Incremental tolling may strand explorer gas, Anderson said.

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Communications At Work in Alaska
Corps issues decision on two Alpine satellites

Permits approved for CD-3 and CD-4, the Fiord and Nanuq discoveries, which will share a drilling rig between winter and summer seasons

By KRISTEN NELSON
Petroleum News Editor-in-Chief

The U.S. Army Corps of Engineers issued a record of decision on two Alpine satellites Dec. 6, approving an application by ConocoPhillips Alaska to expand their existing facility in the Colville River Delta on Alaska’s North Slope.

The Corps was a cooperating agency in the record of decision for the Alpine satellite project signed Nov. 8 by the U.S. Bureau of Land Management, the lead agency on the project. The Alpine satellite project includes five satellite drilling pads, all of which will feed back into existing Alpine facilities for crude oil processing.

The Corps said ConocoPhillips Alaska divided their Alpine satellite development proposal into two parts near the end of the environmental impact statement process, and the permits approved by the Corps cover CD-3 and CD-4, the Alpine satellites at the Fiord and Nanuq discoveries on state leases within the Colville River unit.

The Corps said Alaska District Engineer Col. Timothy Gallagher approved the proposal “with modifications and stipulations to reduce and minimize expected impacts and protect the environment.”

ConocoPhillips Alaska proposed culvert batteries for two road crossings of a paleo-channel leading to CD-4. “As discussed in the EIS, the environmentally preferred alternative ... containing bridges with open spans is an apparent practicable alternative to culvert batteries,” the Corps said. During break-up events, the paleo-channel “conveys flow to area lakes” and

New regulations since last work in 1989

For Devon it has been a pioneering experience as the first company to deal with environmental and socio-economic regulations introduced since the industry pulled out of the Beaufort in 1989.

Now that the comprehensive study has satisfied federal authorities and met with a “positive response” from the Inuvialuit community, Devon will not have to repeat the process for its proposed four-well program, although individual wells will still need to be screened, said Bill Livingstone, Devon’s front coordinator of environmental, regulatory and community affairs.

To retain its four exploration licenses covering 846,000 acres and carrying work commitments of $322.5 million, Devon must drill four wells by the 2008-09 winter.

Devon takes Beaufort plunge

Canadian unit of Devon Energy files detailed study with National Energy Board, signaling intention to drill first exploratory gas well since 1989

By GARY PARK
Petroleum News Calgary Correspondent

Devon Canada is blaring new tracks to reactive drilling in the Canadian Beaufort Sea after a lapse of 15 years.

The Calgary-based unit of Devon Energy has submitted a comprehensive study to Canada’s National Energy Board that sets the stage for an exploratory natural gas well in the 2005-06 winter that revives old dreams of tapping a possible 50 trillion cubic foot storehouse.

Having spent the last 30 months engaged in the most detailed consultations yet involving development of the Beaufort, the company is “ready to roll” with a well in the shallow waters north of the Mackenzie River Delta, Michel Scott, vice president of government and public affairs, told Petroleum News.

Devon is the first company to deal with environmental and socio-economic regulations introduced since the industry pulled out of the Beaufort in 1989. Now that the comprehensive study has satisfied federal authorities and met with a “positive response” from the Inuvialuit community, Devon will not have to repeat the process for its proposed four-well program, although individual wells will still need to be screened, said Bill Livingstone, Devon’s front coordinator of environmental, regulatory and community affairs.

To retain its four exploration licenses covering 846,000 acres and carrying work commitments of $325 million, Devon must drill four wells by the 2008-09 winter.
continued from page 14

CORPS

the flows “are important for lake recharge, fish migration and water quality.”

The Corps offered ConocoPhillips an alternative: the company can either install bridges with minimum 25-foot open spans “or hydraulically equivalent culvert batters, but if it chooses the culvert batters, the Corps must approve the final design and would require monitoring. “Should monitoring demonstrate the culvert installation to be deficient, bridging or other hydraulic improvements would be required,” the Corps said.

ConocoPhillips has applications in for remaining satellites

ConocoPhillips Alaska spokesperson Dawn Patience told Petroleum News Dec. 7 that the company is pleased the Corps of Engineers has completed work on the CD-3 and CD-4 permits; she said the company has an application in with the Corps for the remaining three Alpine satellites.

The Corps said in its decision that ConocoPhillips requested that it proceed with decisions on CD-3 and CD-4, while the company continued to address information requests the Corps has made for other portions of the Alpine satellites project.

The Corps spokeswoman Pat Richardson said Nov. 7 that the Corps has an application from ConocoPhillips for the other three satellites, CD-5, CD-6 and CD-7. These satellites include a connecting road from the existing CD-2 that would require crossing the Nuiqsut Channel, as well as other streams and rivers.

She said ConocoPhillips “last indicated they would continue work on these applications ‘after the first of the year.’

CD-3, CD-4 will share a drilling rig

The Corps said CD-3 and CD-4 “are interdependent because they will share a single drill rig, drilling at CD-3 during winter and at CD-4 during summer,” ConocoPhillips revised spill plans for CD-3, eliminating a gangway and floating dock, and will use other spill strategies, so “no boat ramps or floating docks are included in this authorization,” the Corps said.

Revisions to ConocoPhillips’ application provided to the Corps in October deleted boat launching facilities, changed the CD-3 road design, provided for a shorter airstrip at CD-3 and changed location and type of arming.

Continued from page 14

DEVON

Scott said the initial well will cost C$55 million to C$60 million, down sharply from earlier estimates of C$80 million because of the company’s decision to drill in shallower waters.

The projected water depth is 40 feet and Devon said in its comprehensive study that at the nine offshore drilling locations it has identified the average water depth is about 11,400 feet.

Using its earlier well cost of C$80 million, Devon had indicated that C$137.7 million would be spent in the Northwest Territories, including C$25.5 million on labor and C$35 million in major equipment, but it has yet to recalculate the local economic impact under the revised budget.

Drilling platform not yet determined

Scott said final choice of a drilling platform has yet to be made between a steel drilling caisson, which involves the use of a former crude oil tank that has been converted into a mobile Arctic platform, and an ice island, constructed from a grounded ice pad, with equipment and materials delivered barged in.

Earlier hopes of attracting a partner for the initial well have been dropped because “we can’t wait forever,” Scott said, although the door remains open for subsequent wells.

He said Devon’s hopes of delivering Beaufort gas to the Mackenzie pipeline in the 2013-2015 period was beyond the planning horizon of potential partners.

There has been a strong indication from Chevron Alaska Resources that it might be a contender for the Beaufort. Others could have included BP Canada Energy, ConocoPhillips Canada, Talisman Energy, Anadarko Canada, Burlington Resources Canada and Encana.

Devon is taking a low-key view beyond the first well. Livingston said the company will be “success driven.”

But it is upbeat based on exploration results from the 1970s and 1980s, when 41 shallow-water wells and 50 deepwater wells resulted in 26 significant discovery licenses and a National Energy Board estimate putting marketable gas at 4.1 trillion cubic feet, compared with 5.8 tcf among the four lead gas owners on the Mackenzie Delta.

The ultimate prize for the Beaufort has been calculated at 52 tcf, compared with just 13 tcf for the Delta.

Domes led earlier exploration

Before 1990 the Beaufort was the scene of feverish activity, led by now-defunct Dome Petroleum, which had up to 2,000 workers in the area, the world’s largest Arctic fleet and operated a daily flying 737 service to the area.

Underpinning its ambitious efforts was a federal Petroleum Incentives Program, which covered 55 percent of frontier exploration costs by Canadian-controlled companies and 25 percent of those by foreign-controlled companies.

Those subsidies have long since been scrapped and Scott noted that this time Devon is “going back to the Beaufort with our own dollars.”

Devon acquired its exploration leases covering 850,000 acres in taking over Anderson Exploration for US$3.4 billion in 2001.

It is also active onshore, having struck gas in partnership with Petro-Canada, posting possible marketable reserves of 100 billion cubic feet with the Tuk M-18 well.

In addition, it is buoyed by the results of 3-D seismic in 2004 and progress on the Mackenzie Gas Project.

Now that Imperial Oil has filed the main Mackenzie applications with the National Energy Board, the delivery system is a realistic prospect.

Scott said discussions with the Mackenzie project partners are taking place on the size of a pipeline and access policies for producers outside the main gas owners. He said those talks are “moving along OK.”

The exhaustive work Devon has undertaken on the environmental and socio-economic front has led to “very positive” results from federal authorities and the Inuvialuit Settlement Region in the Delta area, Livingston said.

“We’ve been very pro-active and we’ve heard a lot of compliments about our scientific and traditional work that is included in the comprehensive study,” he said.

Efforts have also been made to involve non-governmental organizations, and although they have not taken an active role “we have kept them in the loop, with no adverse reaction,” Livingston said.●
Northern Dynasty uncovers zone rich in molybdenum at Pebble

Company opts for bigger stake in promising Southwest Alaska gold-copper-molybdenum mine

Northern Dynasty Minerals Ltd. has discovered a new higher-grade zone on the east side of the Pebble gold-copper-molybdenum deposit in south-central Alaska. The discovery is a continuation of mineralization that had been detected to the west of Pebble’s Main Deposit. The new East Zone is part of that western extension, and is 2,000 feet long by 2,000 feet wide, with similar geology and features to the Central Zone of the Pebble deposit, Thiessen said.

By ROSE RAGSDALE

Petroleum News Contributing Writer

Northern Dynasty has acquired a 50 percent interest in the East Zone and has the option to acquire up to a 90 percent interest by December 2015. By exercising its options, Northern Dynasty gained a 90-day period to determine whether to acquire the remaining 50 percent ownership interest in the mine.

Exploration interest also acquired

Northern Dynasty, which had until Nov. 30 to exercise its options, also chose to acquire up to a 50 percent interest in the exploration lands surrounding Pebble. To exercise the option, the company had to complete more than 60,000 feet of drilling on the exploration lands. Teck Cominco has 90 days to form a 50-50 joint venture with the company on the exploration lands, or sell its 50 percent interest in the exploration lands to Northern Dynasty for $4 million in cash or shares, depending on Northern Dynasty’s preference. Teck Cominco would then retain a 5 percent after-pay-back net profits interest in any mine located on the exploration lands.

By exercising its options, Northern Dynasty also gained a 90-day period to decide whether to acquire the remaining 20 percent ownership interest in the mine, held by a related party. In exchange for common stock equal to the independently appraised value of the 20 percent interest, Northern Dynasty could acquire full ownership of the main Pebble deposit (with no back-in right or royalty) and at least 40 percent interest in the surrounding exploration lands.

East Zone uncovered this year

Thiessen said results from drilling, engineering and environmental studies at the Pebble site earlier this year uncovered the East Zone. The work, which involved $25 million in spending, was designed to provide detailed data for a feasibility study and environmental impact statement for a large-scale open pit mining operation.

The substantial size of the new zone demonstrates that Pebble has multiple sources of mineralization and offers significant implications for the deposit model and mine operations currently being planned for the site, he said. The United States Geological Survey has said Pebble is the most extensive mineral system of its type in the world. It includes the central deposit and several porphyry gold-copper-molybdenum deposits and gold occurrences spread over an area two miles long by 1.2 miles wide about 86 miles west of Cook Inlet. Though the new zone is expected to add substantially to Pebble’s inferred resource, it is too soon to estimate to what extent, Eric Bertsch, a Northern Dynasty spokesman, said Nov. 29.

“We’re still waiting for samples from well over 100 holes to get back from the assay labs,” Bertsch said.

An inferred eastern source area for the East Zone mineralization requires substantial additional drilling to establish its full potential, he added.

Drilling found more molybdenum than expected

However, it is especially significant that the latest drilling revealed “more than anticipated” amounts of molybdenum, a metal used to harden steel, Bertsch said.

Thanks to short supplies worldwide, prices for the mineral have climbed recently to more than $27 per pound, up sharply from $4.90 per pound last year. At current prices, the molybdenum ore at Pebble could pay for a conventional pipeline crossing the Pebble deposit (with no back-in right or royalty) and at least 40 percent interest in the surrounding exploration lands.

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FUNDING

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The division reported that Marathon brought in two well control experts from Wild Well Control Inc. in Houston and a 6 percent potassium chloride solution was pumped into the well, reducing pressure at the wellhead to zero Dec. 3.

Richardson said all those concerned, including DEC and agencies in the unified command, Marathon and others working on the well, thought the well had been killed, but by the next day, Saturday Dec. 4, pressure had built back up, so the “kill” procedure had to be repeated. Ultimately it took until Monday, Dec. 6, before there was no longer pressure build-up in the well and Marathon was able to replace the tree.

“The leak of natural gas from the 1-A well at Beaver Creek was successfully stopped today,” Richardson said Dec. 6.

She said that once the leak was stopped it is now safe to go into the site and investigate the cause of the fire.

The field remains shut down.

“We hold 100 percent interest in the Beaver Creek field which produces approximately 200 barrels of oil per day and 20 million cubic feet of natural gas per day. And production is currently shut in.”

Richardson said Marathon is meeting its natural gas contract obligations from its other production in Cook Inlet.

—KRISTEN NELSON
companies involved in North America’s oil and gas industry

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Susanne R. Turner, VP finance and administration

Northern Air Cargo Inc.

Northern Air Cargo’s 275 employees provide scheduled cargo service to 19 Alaska destinations, moving some 80 million pounds of cargo annually. A package express service and charter operations meet other client cargo needs. The company’s NAC-LINK division provides time-sensitive global transportation and logistics services. For Alaska’s remote communities, Northern Air Cargo is their lifeline.

Susanne Turner spent eight years in public accounting in Connecticut and Anchorage with Arthur Andersen and Deloitte & Touche. She joined NAC in 1999 as corporate controller and was promoted to her current position in 2002. Spending time in the outdoors and painting are big interests for Susanne, along with supporting the arts in Anchorage and children’s organizations.

A.B. Brown, terminal manager

Weaver Brothers Inc.

Weaver Brothers operates one of Alaska’s largest trucking companies from terminals in Anchorage, Kenai and Fairbanks. Dependability, safety and quality have been the company’s hallmarks for some 57 years. The company’s 160 trucks and 300 trailers operate year-around carrying everything from perishables to drilling rigs to asphalt and hazardous materials.

A.B. Brown worked as a flight station technician for ARCO at Prudhoe Bay in the 1970s and switched from energy to transportation in 1981. He worked for Sea-Land Services in Anchorage and Tacoma, Wash., and moved back to Alaska in 2001 to join Weaver Brothers. He’s married, with five children and nine grandchildren.

He likes Gandhi’s counsel: “Live like you will die tomorrow; learn like you will live forever.”

All of the companies listed above advertise on a regular basis with Petroleum News.
gas pipeline; regulations mandated by Congress when it enacted the Alaska Natural Gas Pipeline Act Oct. 13.

Alaska Gov. Frank Murkowski told the commission the state is negotiating fiscal terms for a pipeline under the Alaska Stranded Gas Development Act. But, he added, the state still hasn't received a response from the three North Slope producers on the state's proposal for equity ownership, expected in November and now put off until mid-December. The state is also negotiating with pipeline company TransCanada.

Murkowski is concerned FERC's proposed open season regulations don't address access for non-state entities, and "they should," he said. Access to the pipeline by explorers is also crucial, because it would " foste" rpetition," he said, and the state wants to encourage more exploration and development. He also said it is important to establish the rules of the game for explorers in initial open season and in expansions. U.S. Sen. Lisa Murkowski, R-Alaska, told the commission the duration of the open season is critical because a number of Alaska firms or other bodies will desire to become shippers. That commitment, she said, would be enormous, yet little information is available and the Alaskans will need a long open season or information before the open season begins.

**Legislature also concerned about access**

The Alaska Legislature's Budget and Finance Committee continued from page 1

**ACCESS**

The Alaska Legislature's Budget and Finance Committee continued from page 1

**TASK**

range from 3 trillion to 6 trillion barrels, 3 trillion barrels of which are recoverable.

"Estimates of unconventional resources are also large," Tillerson said, noting that an estimated 4 trillion barrels of in-place heavy extra heavy oil and oil sands are concentrated in Canada, Venezuela, Russia and the Caspian Sea.

Based on "ever-improving recovery factors" of 20 to 25 percent, he said, 900 bil- lion to 1 trillion barrels of heavy oil could be recovered over time, an amount equal to all conventional oil produced to date.

Moreover, it's estimated that oil shale deposits containing an estimated 3 trillion barrels exist, half of which are located in the Green River formation of the western United States.

"The point being there are resources in place globally sufficient to achieve the levels of demand the world needs in the demand well into the middle part of this century," Tillerson said.

However, he said that while non-OPEC countries are expected to satisfy most of the growth in oil demand through the end of the current decade, the call on OPEC crude grows rapidly thereafter, "requiring OPEC to add more than 2.5 million barrels per day of capacity each year."

**Gas growth projected at 2.2% per year**

On the gas side, ExxonMobil forecasts that overall growth from now until 2030 will be about 2.2 percent a year, the fastest growing among the major forms of energy. Power generation alone will account for about half of the growth, the company said.

"On a global basis, an increasing portion of total gas demand is coming from cross border and trans-continental from exporting regions to importing regions," Tillerson said.

He said "the scale and versatility" to meet the "foreseeable future," fossil fuels are "the answer," with 100 percent less carbon dioxide emissions compared to coal.

"ExxonMobil projects that liquefied nat- ural gas will represent about 14 percent of total world gas demand in 2020, or only slightly more than a third of the "global interregional gas trade." LNG volumes are expected to grow close to 300 percent by 2030, from 16 bcf per day to 65 bcf per day, the company said.

**Europe largest importer**

Europe will continue to be the largest importer of natural gas, with imports expected to grow from a current 40 percent of supply to 70 percent in 2030, according to ExxonMobil. Pipeline supplies from the Russian and Caspian regions and North Africa will continue to represent Europe's major sources of gas imports, with LNG shares being significant.

Imports into North America and Asia are expected to continue growing to more than 20 bcf per day by 2030.

"Over this time frame, natural gas will shift from a regional to a more global mar- ket, enabled by advances in LNG," Tillerson said.

However, meeting future oil and gas demand "assumes that governments are willing to provide access to resources with sufficient fiscal certainty to encourage investment by industry," he said. "These opportunities are capital inten- sive and are often in remote areas and in difficult physical environments," Tillerson added.

"The state would need to be secured," he added. ExxonMobil has envisioned a more diversified energy mix by 2030, one that includes more wind and solar-generated power, for example, along with more fuel- efficient automobiles and more stringent regulations governing greenhouse gas emis- sions. Without causing the pressure on oil and gas supplies, the company said, world- wide energy demand would rise to 450 mil- lion barrels of oil equivalent per day by 2030, rather than the 335 million barrels per day in the current forecast.

"Europe and Asia are expected to grow energy consump- tion, an increase of more than 100 million barrels per day (if we simply stand still)," said Alan Kelly, ExxonMobil's general manager for North America, petrochemicals. However, ExxonMobil believes that for the "foreseeable future," fossil fuels are likely to be the only energy forms that have "the scale and versatility" to meet the growth in energy demand.

"If we can't meet the significant supply and demand challenges, then economic growth is likely to be compromised," Kelly said.

continued from page 1

Audit Committee held hearings on the gas pipeline. Chair Rep. Ralph Samuels, R- Anchorage, and vice-chair Sen. Gene Therriault, R-Anchorage, brought the com- mittee's views to the commission.

Samuels said the as-yet undiscovered and undeveloped potential for natural gas on the North Slope would be as much as 250 trillion cubic feet, and said the Legislature wants to make sure "certain entities" can't limit access to the pipeline that "no entity has the ability to turn the spigot off."

Presubscription or the anchor shippers concept, where companies can sign up for capacity before an open season, could be a problem, he said, because there will be only one pipeline, and presubscription could tie up the pipeline and new gas would have nowhere to go.

He also encouraged the commission to adopt a "rolled-in" pricing model. The pro- ducers need certainty for investment, he said, but do so explorers: for access and pricing.

Therriault encouraged the commission to "think outside the box" on its open-season regulations for the Alaska gas pipeline and to "address expansion issues now" because of the long lead times for exploration. Explorers, he said, must have some assurance a pipeline will be expanded when capacity becomes exhausted. He said, and explorers also need to know how expansion will be priced.

How capacity will be awarded needs to be more flexible, Therriault said, and not left up to the pipeline sponsors. He also said the commission needs to set a pricing methodology for expansions, telling the commission he believes "incremental pric- ing would have a chilling effect on explo- ration investment in Alaska."

**State could be investor, part owner**

Bill Corbus, commissioner of the Alaska Department of Revenue, said the commis- sion is negotiating equity owner- ship in the pipeline and if the state becomes an investor and part owner in the gas pipeline, we "need to know the regulatory rules of the road."

He said the administration favors a sepa- rate FERC inquiry into expandability and the issue of rolled in vs. incremental pricing.

Corbus said size and design of the pipeline are critically important to both ship- pers and pipeline owners. He said the state encourages early involvement of the FERC in an open season to ensure that information of potential market "is available to all shippers and companies involved in the pipeline."

"We need the commission to certify the rules of the road," he said. A "fair capacity allocation methodology must be implemented," he said.

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Shell’s conventional reserves and allow have a meaningful bottom-line impact on quoted in news reports following Shell’s Canaccord Capital Corp. in Toronto, was itself,” Terry Peters, an analyst with tting smaller but this is significant in Canadian Rockies.
The sizes of the discoveries are getting smaller but this is significant in itself,” Terry Peters, an analyst with Canaccord Capital Corp. in Toronto, was quoted in news reports following Shell’s announcement of the discovery. “It will have a meaningful bottom-line impact on Shell’s conventional reserve and allow them to sustain their Western Canadian production.”

Shell said it made the discovery using proprietary computer technology involving three-dimensional seismic that was developed by Shell International.

“Our foothills exploration team used sophisticated technology and know-how to map, successfully drill and test a new and significant structure in a basin that is generally considered mature,” Ian Kilgour, Shell Canada senior vice president of exploration and production, said in a statement.
The raw gas contains about 60 percent methane and 35 percent hydrogen sulfide.

It is close to sour gas processing facilities and is scheduled to be tied-in and producing by mid-2005. Further delineation drilling is planned for next year.

Shell Canada’s third quarter gas production averaged 416 million cubic feet per day, down 13 million from a year earlier.

Shell Canada has a 75 percent interest in the Tay discovery. Mancal Energy, a company controlled by Calgary’s Mannix family, has a 25 percent interest.

—GARY PARK & KAY CASHMAN

ACCESS

ternal pricing, but address them later, in a sep- arate proceeding.

As for what needs to be established before an open season, Irwin said the state believes the method should be well under- stood for oversubscription to an initial line; and said if more gas is nominated than the capacity of the line, then all bids of 20 years or more should be treated equally, and pro-rated if necessary, to prevent shippers with gas available now from tying up the line. The best solution, he said, is to build the pipeline big enough to carry all the gas. And, he noted, royalty gas issues and some in-state use issues may be resolved in the ongo- ing negotiations between the state and proj- ect sponsors.

Federal agencies concur on access

Jeff Walker, regional supervisor field operations for the U.S. Department of the Interior’s Minerals Management Service, told the commission MMS believes it is important that FERC regulations allow for new gas access. MMS manages oil and gas leasing and development on the federal outer continental shelf and Walker said “a natural gas transportation project can increase the eco- nomic value” of the agency’s leases. This will only happen, Walker told the commis- sion, if the regulations it adopts allow new gas access to transportation.

Gas resources in northern Alaska are stranded, Walker said, and access to a pipeline would attract new exploration companies. But, he said, new entrants would require “reasonable assurance of access and available capacity” prior to mak- ing the investments required for exploration, which requires long-term planning and staffing.

Colleen McCarthy, Bureau of Land Management deputy state director for ener- gy, said that in the National Petroleum Reserve-Alaska, which BLM manages, the mean estimate for conventional natural gas is 73 tcf, but access to a pipeline is needed for companies exploring.

“Currently all gas resources on the North Slope are stranded,” she said.

If an Alaska gas pipeline project “does not provide access to capacity for compa- nies” exploring in the NPR-A, “federal gas will continue to be stranded,” she said.

Without access to a gas pipeline, “there will be little incentive for companies to invest” in exploration on the North Slope. She noted that companies have told the commission about the risk of investing in the Alaska gas pipeline. “Well, the federal government is providing substantive incentive...

The rest of the story...
have saddled operators with punishing cost overruns that have amounted to billions of dollars.

Upgraders a costly issue

Few know better than Imperial, which has a 25 percent stake in Syncrude, and earlier this year lined up with other partners to swallow some tough medicine when the giant consortium approved an expansion costing C$7.8 billion, 90 percent above initial estimates.

“Building upgraders ... has been less than fun,” Imperial Chief Executive Officer Tim Heam told shareholders and analysts Nov. 30. “That’s about as polite as I can say it.”

Without ruling out an on-site upgrader, he made the challenge clear to Imperial staff.

“Somebody’s going to have to show me how we’re going to build an upgrader a heck of a lot better than any of those alternatives ... it’s going to be a hard hurdle for my organization to convince me that that’s the right path,” he said.

The Kearl project involves two leases owned 100 percent by Imperial and two adjacent leases owned by sister company, ExxonMobil Canada.

A regulatory application should be filed in May and initial production for 2009 or 2010 is pegged at 105,000 bpd, growing to 300,000 bpd. Imperial is already pumping 180,000 bpd from its wholly-owned Cole Lake operations and its Syncrude stake.

Heam said that before embarking on Kearl, which could cost as much as C$8 billion, the company must “take a real hard look” at what it has learned over the last seven years.

In addition to finding an answer in ExxonMobil’s U.S. refineries that could include upgrading the bitumen at Imperial’s Strathcona refinery near Edmonton.

Imperial has also been involved in studying a reversal of a pipeline to ship production from Chicago to Gulf of Mexico refineries which are able to process heavy crude.

“We will look for a path forward that gives us a competitive advantage,” he said.

Syncrude will reduce sulfur dioxide emissions

Separately, Syncrude has approval from Alberta regulators to spend C$400 million reducing sulfur dioxide emissions at its northern Alberta upgrader.

The net effect of the project would be to hold emissions at their current level of 245 megatonnes per year and could improve prices, he said.

Premcor’s Ohio refinery to handle 200,000 bpd of blended oil sands crude

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The hope is that other producers will add to the supply pool, including the Alberta government, with its royalty share of production.

If EnCana gets a positive reception, sales are forecast to reach 450,000 bpd by 2007 and could peak at 1 million bpd.

It is not yet certain what pricing basis will be used, although talks are taking place with the New York Mercantile Exchange.

But EnCana Vice President Walt Madro told the Edmonton Journal WCS will be used by at least half the 19 heavy oil grades now marketed out of Western Canada and will offer a broader appeal to more U.S. refiners.

If the Nymex creates future contracts that could improve prices, he said.

Rapid change in North American oil markets

The rapid change in North American oil markets is reflected in the fact that West Texas Intermediate is down to 350,000 bpd and Brent has dropped to 360,000 bpd, while FirstEnergy Capital is forecasting heavy crudes will surpass 2 million bpd by 2015.

EnCana, which has converted more than 50 percent of its term supply contracts to WCS from January, is involved in a study that could result in a US$1 billion upgrade of Premcor’s Ohio refinery to handle 200,000 bpd of blended oil sands crude.

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In a separate pipeline development, Devon Canada and MEG Energy have created Access Pipeline as a joint venture to study building a C$300 million blended bitumen and diluent pipeline from Christina Lake in northern Alberta to Edmonton.

Although Devon is not committed to owning or operating the pipeline, it views the project as one option for transporting 35,000 bpd from its C$550 million Jackfish project that is aiming for full production by 2009. MEG is working on a nearby pilot project to produce 5,000 bpd of bitumen.

The proposed Access system would offer capacity of up to 400,000 bpd. A regulatory application should be filed in the first quarter of 2005.