Petroleum news

page 10 Susitna hydro pre-app to FERC; AEA plan calls for 2023 startup

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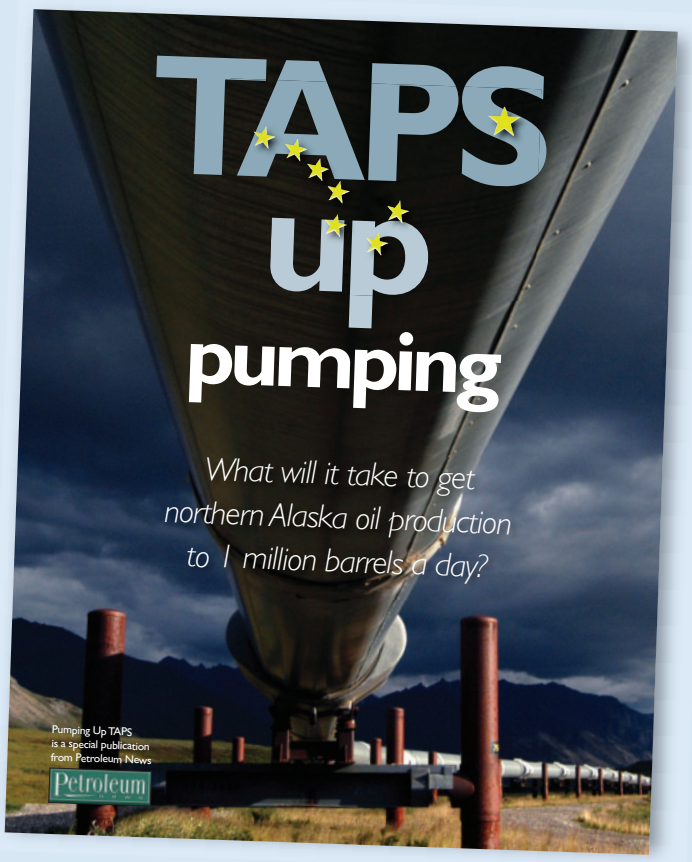
Pumping up TAPS mag debuts



Pumping up TAPS magazine, released by Petroleum News in its Jan. 8 edition, looks at Gov. Sean Parnell's goal to increase North Slope oil production to 1 million barrels a day in 10 years. Special emphasis is given to the task of simply maintaining current levels of production.

Much ado about LNG, Point Thomson at Jan. 5 meeting with BP, Conoco, Exxon chiefs

AMID RUMORS OF A MAJOR ANNOUNCEMENT from Alaska's big three North Slope gas owners, ExxonMobil, BP and ConocoPhillips, involving a change in direction for TransCanada's Alaska Pipeline Project that would take the line to tidewater for liquefied natural gas export to Asia, versus going through Canada to U.S. markets, the movers and shakers in Alaska's oil and gas industry received invitations on Jan. 3 from those companies to a private noon luncheon on Jan. 5 with their chief executive officers — Rex Tillerson, ExxonMobil, Bob Dudley, BP, and Jim Mulva,

see **INSIDER** *page 18*

Marathon puts its Cook Inlet Glacier drilling rig up for sale

Marathon Oil Co. has put its Glacier No. 1 truckable drilling rig up for sale. In a Nov. 17 email to prospective purchasers the company said that it is offering the rig for sale as a package, including the rig itself and all of its associated equipment, together with the rig camp. The email says that the rig went into service in 2000 and was recently upgraded with a 250-ton top drive unit.

"At this time we're evaluating proposals from potential buyers," John Porretto, Marathon external communications specialist, told Petroleum News in a Dec. 29 email.

In 2001 John Barnes, Marathon's Alaska business unit manager at the time, told the Alaska Support Industry Alliance that, with a small surface footprint, total containment of fluids and quiet operation, the Glacier No. 1 rig was purpose designed to operate close to neighborhoods on Alaska's Kenai Peninsula. The rig spud its first well in April 2000 and by

see **GLACIER RIG** *page 24*

PIPELINES & DOWNSTREAM

Pipeline value set

Alaska judge again rules system is worth far more than what owners say

By WESLEY LOY
For Petroleum News

An Alaska judge on Dec. 30 issued another major ruling in the long-running dispute over the value of the trans-Alaska pipeline system for property tax purposes, and it marked another defeat for the owners.

The 216-page ruling from Superior Court Judge Sharon Gleason of Anchorage came after a nine-week trial this fall focusing on the value of TAPS for the years 2007, 2008 and 2009.

The concluding paragraph of the decision says the "full and true value" of TAPS "with due regard to the economic value of the property based on the estimated life of the proven reserves of gas or unrefined oil then technically, economically, and legally deliv-

see **PIPELINE VALUE** *page 22*

The real story on TAPS low-flow threat?

How low can the pipeline go?

That was a key question for an Alaska judge in determining the taxable value of the trans-Alaska pipeline system — at what point does declining production of North Slope crude oil render the oversized pipeline unusable.

This has been a big issue not only in court but in the ongoing public policy conversation over Alaska's oil and gas future. The perceived threat that declining oil production could mean taps for TAPS is often

see **LOW-FLOW THREAT** *page 22*

FINANCE & ECONOMY

Hilcorp deal closes

Houston independent takes over in Cook Inlet for Chevron subsidiary Union Oil

By KRISTEN NELSON
Petroleum News

JOHN BARNES

The closing came as predicted, at the end of the year.

Some of Cook Inlet's oldest oil and gas facilities now have a new owner, with Chevron subsidiary Union Oil Company of California giving way to Houston-based independent Hilcorp, whose Hilcorp Alaska LLC subsidiary assumed operation of Union's Cook Inlet assets Jan. 1.

The sale was announced in July; financial terms were not announced.

In a Jan. 4 statement Hilcorp said it "welcomes over 230 new Alaskan employees to the company and recognizes the skills and experience they bring to the company."

Hilcorp Energy Co., founded in 1989, is one of the largest privately held independent oil and natural gas exploration and production companies in the United States, with 700 employees in the Lower 48.

"Hilcorp continues to grow by actively acquiring and developing conventional assets while expanding its footprint into a number of new

see **HILCORP DEAL** *page 24*

PIPELINES & DOWNSTREAM

Gateway critical test

Enbridge export pipeline about to start two years of hearings and deliberations

By GARY PARK
For Petroleum News

What the Canadian government views as vital to the "national interest," with an estimated C$270 billion in taxes and royalties and thousands of jobs on the line, is on what could be the ultimate collision course for an energy project within Canada.

The curtain on the showdown will be raised Jan. 10 in the Haisla First Nation of Kitamaat Village near Enbridge's proposed Northern Gateway terminus on the Douglas Channel of British Columbia's north coast.

From there the initial public hearings will fan out across northern British Columbia and Alberta — a process the National Energy Board or NEB expects

But it's far from clear that Enbridge has been able to win over the bulk of First Nations, especially those along the pipeline route who have been offered a 10 percent equity stake in the project.

to complete by mid-March, followed by a round of community meetings expected to last until mid-July when more than 4,000 individuals and organizations will make public statements to a joint review panel of the NEB and the Canadian Environmental Assessment Agency.

Interveners will then have a chance to cross exam-

see **GATEWAY TEST** *page 23*

contents

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ON THE COVER

Pipeline value set

Alaska judge again rules system is worth far more than what owners say

Hilcorp deal closes

Houston independent takes over in Cook Inlet for Chevron subsidiary Union Oil

Gateway critical test

Enbridge export pipeline about to start two years of hearings and deliberations

Marathon puts its Cook Inlet Glacier drilling rig up for sale

OIL PATCH INSIDER

ALTERNATIVE ENERGY

EXPLORATION & PRODUCTION

FINANCE & ECONOMY

GOVERNMENT

LAND & LEASING

NATURAL GAS

PIPELINES & DOWNSTREAM

● NATURAL GAS

LNG market changing as gas demand rises

Worldwatch Institute report describes steady growth in gas consumption and production, with a changing LNG distribution pattern

By ALAN BAILEY
Petroleum News

Despite a dip in 2009 following the 2008 financial crisis, worldwide natural gas consumption and production continue on a decades-long upward trend, according to a "Vital Signs" report published in December by the Worldwatch Institute. And, with an increasing number of countries importing liquefied natural gas, or LNG, the geographic pattern of trading in LNG is changing, the report says.

Data through 2010 show an almost linear year-on-year increase in gas usage since 1970 — in 2010 natural gas accounted for 23.8 percent of worldwide primary energy use, the report says.

Unconventional sources

Although proven natural gas reserves only increased globally by 0.3 percent in 2010, research published in recent years suggests that unconventional gas sources such as shale gas, coalbed methane and tight gas sands could hold as much recoverable gas as the conventional gas fields that have been the mainstay of gas production in the past. In 2010 the United States and Canada accounted for the bulk of unconventional gas production, but Australia, Poland, Germany, the United Kingdom and China are all pursuing the development of unconventional gas resources, the report says.

The Middle East and Russia together account for more than 70 percent of worldwide conventional natural gas reserves.

In 2009 and 2010 the United States was the world's largest natural gas producer, just ahead of Russia and accounting for just under one fifth of global gas production, the report says.

In 2010 Russia maintained its position as the world's largest natural gas exporter, with 27.5 percent of the world's pipeline gas trade. However, the opening of new gas pipelines may erode Russian dominance over gas supplies to Eastern Europe. And the European Union has been seeking alternatives to Russian pipeline gas, following supply disruption in 2009 as a result of a dispute between Russia and Ukraine, the report says.

Increased consumption

Natural gas consumption in the United States jumped by 1.3 trillion cubic feet to 24.1 tcf in 2010. Although consumption in Europe increased to 17.7 tcf, Europe's share of global gas consumption dropped after remaining fairly static at around 20 percent for the last three decades, the report says.

Asian demand for natural gas, especially in China, has grown rapidly, with China, India, South Korea and Taiwan all seeing demand growth of more than 20 percent in 2010. China consumed 3.9 tcf of natural gas in 2010 and the country has a strategic plan to double natural gas's share of the country's overall energy mix by 2015, the report says.

And, with the Middle East currently exporting much of the region's prolific gas production, many people view this region has having major growth potential in natural gas usage.

In 2010 there were major disparities in natural gas prices across the world, with the average Henry Hub spot market price in the United States being $4.39 per million British thermal unit, while LNG attained an average price of $10.91 per million Btu in Asia. The average price on the British National Balancing Point Hub was $6.56 per million Btu. All of these prices represented rises from 2009, as gas demand recovered after the world economic recession. However, on an energy-equivalent basis, natural gas in all markets remained cheaper than crude oil, the report says.

More LNG

With a global trade of 10.5 tcf, the share of gas traded as LNG exceeded 30 percent for the first time in 2010. About half of this increase came from Qatar, although LNG production from Australia, Indonesia and Malaysia also increased substantially. Australia, with major coalbed methane and conventional gas resources, accounts for 63 percent of worldwide LNG liquefaction facilities under construction, the report says.

Imports by Asian countries dominated the LNG market in 2010, with Japan in particular importing 3.3 tcf of gas in the form of LNG. South Korea imported 1.57 tcf and China imported 0.45 tcf. Europe imported 3.1 tcf of gas as LNG, while U.S. LNG imports fell as abundant, cheap natural gas supplies became available in North America.

Changing trade

However, with six countries, five of them in South America and the Middle East, starting to import LNG between 2005 and 2010, the global LNG trade is changing, the report says.

Major geopolitical events in 2011 have also impacted the dynamics of the gas market. Political unrest in North Africa disrupted gas supplies from that region over periods of several months. And the tsunami and ensuing nuclear disaster in Japan pushed up gas demand in that country, as gas fueled power generation replaced the generation capacity of shut in or damaged nuclear plants. Continuing opposition to nuclear power will likely continue to push up gas demand, the report says.

According to a recent Platts podcast on European gas markets, a mild winter so far in that continent coupled with new pipelines coming on line have resulted in plentiful supplies of gas in Europe — European gas prices are somewhat lower than a year ago, with an especially large price differential with LNG delivered to the Asian market. Of particular significance for European gas supplies are a new pipeline from Russia to Germany that bypasses Ukraine and a new pipeline from Algeria into Spain, the Platts report says.

Although Europe continues to import LNG and has opened a new LNG terminal, gas buyers in a soft European market are reluctant to pay the oil-indexed prices that Asian buyers accept. But, with high Asian demand, the spot market in LNG is very tight, the Platts report says. ●

Contact Alan Bailey
at abailey@petroleumnews.com

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Kay Cashman	PUBLISHER & EXECUTIVE EDITOR
Mary Mack	CHIEF FINANCIAL OFFICER
Kristen Nelson	EDITOR-IN-CHIEF
Clint Lasley	GM & CIRCULATION DIRECTOR
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Allen Baker	CONTRIBUTING WRITER
Judy Patrick Photography	CONTRACT PHOTOGRAPHER
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Forrest Crane	CONTRACT PHOTOGRAPHER
Tom Kearney	ADVERTISING DESIGN MANAGER
Amy Spittler	MARKETING CONSULTANT
Dee Cashman	CIRCULATION REPRESENTATIVE

ADDRESS
P.O. Box 231647
Anchorage, AK 99523-1647

NEWS
907.522.9469
publisher@petroleumnews.com

CIRCULATION
907.522.9469
circulation@petroleumnews.com

ADVERTISING
Susan Crane • 907.770.5592
scrane@petroleumnews.com

Bonnie Yonker • 425.483.9705
byonker@petroleumnews.com

FAX FOR ALL DEPARTMENTS
907.522.9583

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• EXPLORATION & PRODUCTION

Slight ANS production drop from November

Alaska North Slope crude oil production averaged 622,356 barrels per day in December, down 0.4% from 624,687 bpd in November

By KRISTEN NELSON
Petroleum News

Alaska North Slope crude oil production dropped slightly, by 0.37 percent, from November to December. ANS averaged 622,356 barrels per day in December, down from 624,687 bpd in November.

ANS production in December of 2010 was 641,518 bpd, so ANS production is down 3 percent year-over-year.

December production was down from November at Prudhoe Bay, Kuparuk and Alpine, and up at Endicott and Lisburne.

Except where noted, production volumes are from the Alaska Department of Revenue's Tax Division, which tracks oil production by major production centers and provides daily production and monthly averages.

The BP Exploration (Alaska)-operated Prudhoe Bay field averaged 360,275 bpd in December, down 0.38 percent from 361,656 bpd in November, a drop averaging 1,381 bpd. Prudhoe Bay includes the field's satellites — Aurora, Borealis, Midnight Sun, Orion and Polaris — along with Northstar, an offshore field north of Prudhoe and Milne Point, a field to the west of Prudhoe, all operated by BP.

Revenue has recently combined Prudhoe, Northstar and Milne Point in its reporting; a combined production number for the three fields for December of 2010 was 380,673 bpd, so combined production is down 5.4 percent year-over-year.

Kuparuk also down slightly

December production at the ConocoPhillips Alaska-operated Kuparuk River field averaged 136,586 bpd in December, down 0.33 percent from a November average of 137,038 bpd but up 5.6 percent from December 2010 production averaging 129,323 bpd.

Kuparuk production includes satellites at Tabasco, Tarn and Meltwater, as well as West Sak production. Also included is production from the Pioneer Natural Resources Alaska-operated Oooguruk field and from the Eni-operated Nikaitchuq field.

Total monthly production on a field-by-field and pool-by-pool data is reported by the Alaska Oil and Gas Conservation Commission. The most recent data available from the commission is for November and shows a total of 163,482 barrels from Nikaitchuq, some 5,449 bpd, and 171,421 barrels from Oooguruk, some 5,714 bpd.

The ConocoPhillips-operated Alpine field averaged 78,674 bpd in December, down 2.5 percent from November production of 80,710 bpd and down 9.2 percent from December 2010 production averaging 86,646 bpd. Alpine includes satellite production from Fiord, Nanuq and Qannik.

Endicott production up

The BP-operated Endicott field, averaging 13,135 bpd in December, was up 9.24 percent from a November average of 12,024 bpd, and up 2.4 percent from a December 2010 average of 12,831 bpd. Endicott includes production from Badami on the eastern side of the North Slope, where production was started up again in November 2010. Commission figures for November show total production at Badami of 33,634 barrels, or some 1,121 bpd.

The BP-operated Lisburne field, part of greater Prudhoe Bay, averaged 33,686 bpd in December, up 1.28 percent from a November average of 33,259 bpd, and up 5.12 percent from a December 2010 average of 32,045 bpd. Lisburne production includes Point McIntyre and Niakuk.

Cook Inlet down 5 percent

Revenue no longer reports Cook Inlet production.

Commission figures for November show a total of 308,153 barrels from eight Cook Inlet fields, an average of some 10,272 bpd, down 5.2 percent from an October average of 10,832 bpd from the same fields (Beaver Creek, Granite Point, McArthur River, Middle Ground Shoal, Swanson River, Trading Bay and West McArthur River).

Only three Cook Inlet fields averaged more than a thousand barrels a day in November: Granite Point, 1,946 bpd; McArthur River, 3,994 bpd; and Middle Ground Shoal, 2,312 bpd.

ANS crude oil production peaked in 1988 at 2.1 million bpd; Cook Inlet crude oil production peaked in 1970 at more than 227,000 bpd. ●

Contact Kristen Nelson at knelson@petroleumnews.com

● LAND & LEASING

Western Canada land rush tails off

B.C. goes into tailspin and Alberta faces sharp declines after two provinces pile up C$22.7 billion in auction returns since 2002

By GARY PARK
For Petroleum News

The odds are heavily stacked against a continuation in 2012 of a decade-long multibillion dollar spending spree to secure unconventional exploration rights in Alberta and British Columbia.

Pending realization of Alberta's hopes of discovering commercial quantities or liquids-rich natural gas and British Columbia's dreams of regulatory and corporate approval of liquefied natural gas export projects, the northern regions of both provinces face a sharp decline in bidding at government land auctions.

For the first time since 2002, the two provinces face combined returns of less than C$1 billion in sales revenues.

British Columbia found itself on the skids in 2011, fetching C$223 million from 191,534 hectares (473,280 acres) in 2011 — its lowest dollar value since 1999 and its lowest acreage since record were first kept in 1978.

Brad Hayes, president of Petrel Robertson Consulting, said that unless there is success from early wells being drilled in British Columbia's Liard basin, Cordova Embayment and the northern end of the Montney fairway it is doubtful 2012 sales will even match those of 2011.

Alberta, after accumulating staggering returns of C$3.54 billion in 2011 and C$2.39 billion in 2010, is expected to start a sharp decline this year.

Over the past decade the British Columbia treasury has swelled from C$7.7 billion in cash bonuses as E&P companies have fastened on to the potential for horizontal drilling and multistage fracturing in unconventional plays.

Alberta has almost doubled that bonanza, collecting C$15 billion, initially from the oil sands then over the past two years from its oil and liquids-rich shale prospects.

Best prospects tied up

Observers believe that companies have now largely tied up the best exploration prospects.

A host of challenges now awaits the two provinces, including the long-range forecast for low gas prices, saturated North American markets, the lack of pipelines and related infrastructure in British Columbia's remote plays, environmental and landowner opposition to well fracking and unresolved First Nations land claims in British Columbia.

The industry has credited drilling and royalty incentives in both provinces for the surge in bidding and is now hoping British Columbia will be open to further stimulus packages involving its deep gas credit and oil royalty framework.

Gary Leach, executive director of the Small Explorers and Producers Association of Canada, said his membership of junior and intermediate producers urgently need to find a "catalyst that will move the needle in B.C."

Energy Minister Rich Coleman has already indicated the British Columbia government is ready to consider lowering royalties to capture more long-term exploration spending, especially if that helps create long-term jobs.

Gas reserves up in B.C.

Bolstering the prospects in British Columbia, the province's Oil and Gas Commission disclosed in December that remaining raw gas reserves rose in 2010 by 42 percent to 33.1 trillion cubic feet, the 10th straight year of increases.

The OGC said Horn River had 98 producing shale gas wells at the end of 2010, the latest available count, but results from those wells remain confidential under the terms of approvals for experimental schemes.

Horn River formations account for 10 percent of British Columbia's gas production of about 1 billion cubic feet per day, compared with 26 percent in the more established Montney play, which has 383 wells.

The best prospect of boosting upstream activity in British Columbia hangs on an early decision by Apache, Encana and EOG Resources to proceed with their Kitimat LNG project to access the lucrative Asian market and ensure a robust energy sector.

In the meantime, Hayes said, companies with a stake in LNG facilities will probably do their best to slow short-term investment commitments until more of the uncertainties around pipelines and project permits have been removed.

Public opposition to advanced technology

If British Columbia and Alberta are to translate land sales into exploration and development they have to deal with mounting public opposition to the use of advanced technology in resource plays.

The Dene Tha' First Nation of British Columbia has already set in motion a possible landmark case by taking the province to court over concerns about shale gas development in the emerging Cordova Embayment.

The lawsuit has challenged the British Columbia Ministry of Energy and Mines' decision in 2010 to sell oil and gas tenures in the Cordova play and wants a moratorium on exploration until the government conducts a large scale environmental impact study and introduces regulations covering the use of shale gas technologies.

Alberta Energy Minister Ted Morton, acknowledging the public concern across North America about the safety of multistage hydraulic fracturing, said his government is eager to be a leader in the "safe and responsible development of unconventional oil and gas."

To that end, he said the New West Partnership — an economic relationship of British Columbia, Alberta and Saskatchewan — is committed to introducing a public online registry, where companies will voluntarily post the chemicals they use in fracking fluids, noting that public reporting is mandatory in Texas.

Lack of baseline water testing

He said the lack of baseline water testing in a fracking dispute in Wyoming is contributing to public uncertainty about shale gas development, reinforced by a U.S. Environmental Protection Agency report in

see **LAND RUSH** *page 7*

● PIPELINES & DOWNSTREAM

Unocal gets another TAPS bump

All rate cases on hold while RCA and FERC hear testimony on a consolidated docket connected to Strategic Reconfiguration

By ERIC LIDJI
For Petroleum News

The Regulatory Commission of Alaska temporarily approved a 7 percent increase to the rate Union Oil Company of California, or Unocal, charges to move crude oil through the trans-Alaska oil pipeline to markets in the state, but will hold off on investigating the matter further until a larger and related rate case currently in hearings reaches a conclusion.

The increase allows Unocal to charge $3.31 to ship a barrel of oil from the North Slope to North Pole and about $5.18 to ship to Valdez, depending on the final destination. (There are two off-take points in Valdez: the PetroStar refinery and the Valdez Marine Terminal.) Under temporary rates approved last year, Unocal currently charges $3.07 per barrel to ship to North Pole, and about $4.83 per barrel to ship to points in Valdez.

The increase went into effect on Jan. 1, 2012.

The company previously said it needed the increase to offset declining throughput at a time of rising operating costs. The increase should bring Unocal about $14.7 million per year, compared to the $13.7 million it was previously earning on in-state business.

Ownership of the pipeline is divided among subsidiaries of BP, ConocoPhillips, ExxonMobil, Koch and Unocal. Unocal owns the smallest stake at 1.36 percent.

Unocal, through its affiliate Chevron, is keeping its North Slope assets, including its interest in the pipeline, despite recently selling its Cook Inlet assets to Houston-based independent Hilcorp Alaska LLC.

Conclusion delayed

Unocal will likely be collecting the increase on a temporary basis for a while.

The RCA and the Federal Energy Regulatory Commission are holding hearings on a consolidation 12-docket proceeding — consisting of three rate cases each from four of the companies that own undivided stakes in the pipeline. ConocoPhillips, Koch and now Unocal have since filed additional rate cases. Because those cases hinge on issues at play in the larger proceeding, the RCA put them on hold until consolidate case is resolved.

That larger case primarily concerns whether and how the owners of the pipeline can recover the costs of Strategic Reconfiguration, an over-budget upgrade on the pipeline, but third parties, including the State of Alaska, the independent producer Anadarko Petroleum Corp., and the refining company Tesoro Corp. have also challenged details such as the depreciable life of the pipeline and the nature of declining throughput.●

Contact Eric Lidji at ericlidji@mac.com

continued from page 5

LAND RUSH

December that suggested fracking probably caused water contamination in a Wyoming community — a claim that is being disputed by Encana.

Emphasizing the importance to Alberta of dealing with the issue, Morton said his province is "right on the front edge of a new renaissance in unconventional oil production" in the Cardium, Viking and Duvernay formations that spurred the 2011 land sales.

Morton said he and Environment Minister Diana McQueen are also working to bring oil and gas approvals under a single regulator, targeting new regulations this summer.

David Collyer, president of the Canadian Association of Petroleum Producers, said his organization supports any requirement to test surface water and water wells that are tied to fracking activities, starting with baseline monitoring before activity starts. ●

Contact Gary Park through publisher@petroleumnews.com

● NATURAL GAS

Chugach applies for new storage costs

Tells RCA these are costs previously bundled as part of gas supply contracts; CINGSA storage will be purchased on unbundled basis

By KRISTEN NELSON
Petroleum News

Natural gas storage isn't new in Cook Inlet, but third-party gas storage is.

Chugach Electric Association told the Regulatory Commission of Alaska in a Dec. 15 tariff filing that storage costs are not new, but said they were previously part of bundled services embedded in Chugach's gas supply contracts.

Chugach is contracting for storage with Cook Inlet Natural Gas Storage Alaska, owned by Semco Energy (parent company of Enstar Natural Gas, the Southcentral Alaska gas distribution utility), MidAmerican LLC, First Alaska and Cook Inlet Region Inc.

Chugach is requesting approval from the commission to recover natural gas storage and related transportation, injection and withdrawal costs through a quarterly fuel and purchased power adjustment mechanism. It is also requesting approval of its proposed methodology of recovery of the costs in rates.

Project certificated in 2011

The commission granted Cook Inlet Natural Gas Storage Alaska, or CINGSA, a certificate of public convenience and necessity for storage of natural gas on the Kenai Peninsula in January 2011. The commission also approved the tariff. The commission said CINGSA's initial customers agreed that gas storage was needed and that only CINGSA's proposed gas storage services were likely to meet the utilities' urgent need for storage services.

Chugach is requesting commission approval to continue recovering gas storage costs through the established quarterly fuel and purchased power adjustment process.

Chugach said in its tariff filing that the costs are not new, but "were previously incurred and recovered through the surcharge process through bundled services embedded in the price contained in Chugach's prior gas supply contracts. These services are now being purchased on an unbundled basis."

The unbundled costs include cost of gas in storage; transportation of gas from the field to the storage injection point; injection costs; withdrawal costs; transportation of gas from storage; interest carrying charges; and storage reservation and capacity costs.

Volumetric and fixed recovery

Chugach said all storage costs were previously recovered through one bundled price, but it is proposing that costs be assigned to appropriate seasonal periods, ensuring cost recovery from customers as they benefit from storage.

Specific gas storage cost elements are a direct function of system use and would be recovered on a volumetric basis, including transportation costs, injection and withdrawal costs, value of stored gas and attendant interest carrying costs.

Chugach said gas in storage would be valued on an average cost basis calculated on the association's total cost of gas in storage divided by the total stored gas quantities.

Chugach is also proposing a monthly carrying cost based on its short-term interest rate on the basis of the total cost of stored gas, so that customers receiving the benefit of gas from storage will pay the attendant costs. Interest carrying costs cost total between $200,000 and $2 million annually, Chugach said, depending on interest rates, amount of gas in storage and gas prices. The association said it is required to pay reservation and capacity fees to use gas storage, from which members benefit throughout the year, and the methodology ensures customers pay for the standby value of storage.

The storage reservation and capacity costs would be charged on a monthly basis. The annualized fixed reservation and storage capacity costs are estimated to total $7.8 million initially but decrease to $6.6 million by 2017 as the contracted capacity is reduced from 2.4 billion cubic feet to 1.6 bcf. ●

Contact Kristen Nelson at knelson@petroleumnews.com

• GOVERNMENT

Obama, Congress begin 2012 in dispute

Issue is 1,700-mile Keystone XL pipeline from western Canada to Texas refineries; payroll tax cut gave administration only 60 days

By MATTHEW DALY
Associated Press

President Barack Obama and Congress are starting the election year locked in a tussle over a proposed 1,700-mile oil pipeline from Canada to Texas that will force the White House to make a politically risky choice between two key Democratic constituencies.

Some unions say the Keystone XL pipeline would create thousands of jobs. Environmentalists fear it could lead to an oil spill disaster. Obama enjoyed strong support from both groups in his winning 2008 campaign for the White House.

A law Obama signed just before Christmas that temporarily extended the payroll tax cut included a Republican-written provision compelling him to make a speedy decision — within 60 days — on whether to build the pipeline. The administration is warning it would rather say no than rush a decision in an election year.

The pipeline would carry oil from tar sands in western Canada to refineries in Texas, passing through Montana, South Dakota, Nebraska, Kansas and Oklahoma. The project's developer, Calgary-based TransCanada, says the pipeline could create as many as 20,000 jobs, a figure opponents say is inflated. A State Department report last summer said the pipeline would create up to 6,000 jobs during construction.

Environmental advocates, already disappointed with Obama's failure to achieve climate change legislation and the administration's decision to delay new smog standards, have made it clear that approval of the pipeline would dampen their enthusiasm for him in November's election.

Re-election funds at issue

Environmental advocates, already disappointed with Obama's failure to achieve climate change legislation and the administration's decision to delay new smog standards, have made it clear that approval of the pipeline would dampen their enthusiasm for him in November's election.

Some liberal donors threatened to cut off funds to Obama's re-election campaign to protest the project, which opponents say would transport "dirty oil" that requires huge amounts of energy to extract.

If he rejects the pipeline, Obama risks losing support from organized labor, a key part of the Democratic base, for thwarting thousands of jobs.

Obama appeared to have skirted the issue in December when the U.S. State Department announced it was postponing a decision on the pipeline until after the 2012 election. Officials said they needed extra time to study routes that avoid an environmentally sensitive area of Nebraska that supplies water to eight states.

The new route would have to be approved by Nebraska environmental officials and the State Department, which has authority because the pipeline would cross an international border.

An "arbitrary deadline" for the permit decision would compromise the process, with time needed to conduct required environmental reviews, the State Department warned in a written statement on Dec. 12. Obama administration officials confirmed that view after the payroll tax bill was approved.

Republicans cite jobs

Republicans call the threat little more than an excuse that allows Obama to placate environmental groups while not rejecting the pipeline outright.

"The only thing arbitrary about this decision is the decision by the president to say, 'Well, let's wait until after the next election,'" said House Speaker John Boehner.

Boehner and other Republicans say the pipeline would help Obama achieve his top priority — creating jobs — without costing taxpayer money. They hope to portray Obama's reluctance to approve the pipeline as a sign he favors environmentalists over jobs.

Russ Girling, TransCanada's president and chief executive, said his company would do whatever is necessary to make sure the project is approved.

In Nebraska, where the pipeline faces strong resistance, state officials are awaiting an environmental study that will determine a new route. Officials have said the review will take six to nine months.

Canada touts West Coast route

Project supporters say U.S. rejection of the pipeline would not stop it from being built. Canadian Prime Minister Stephen Harper has said TransCanada could pursue an alternative route through Canada to the West Coast, where oil could be shipped to China and other Asian markets.

"Canada is going to develop this no matter what, and that oil is either going to come to the United States or it's going to go to a place like China. We want it here," said

see KEYSTONE DISPUTE page 17

● GOVERNMENT

Navigating the Endangered Species Act

Early informal consultation with agency or taking other pre-emptive action can help reduce the risk of project disruption

By ALAN BAILEY
Petroleum News

For anyone pursuing a project that may impact a species listed under the Endangered Species Act, it is very important to talk informally to the appropriate government agency at an early stage, to engage the government biologists in discussions over any issues that may be involved, Svend Brandt-Erichsen, partner in Marten Law LLC, told the Law Seminars International's Energy in Alaska conference on Dec. 2. Once an agency makes an Endangered Species Act ruling, it is extremely difficult to have that ruling overturned — courts are reluctant to second guess the views of agency experts on biology issues and will likely only overturn a ruling on the basis of some procedural flaw, Brandt-Erichsen said.

The National Marine Fisheries Service, within NOAA, and the U.S Fish and Wildlife Service, within the Department of the Interior, are responsible for administering both the Endangered Species Act and the Marine Mammals Protection Act. The National Marine Fisheries Service deals with marine animals such as whales, while Fish and Wildlife deals with land species and some marine animals such as polar bears and walrus.

Federal involvement

The Endangered Species Act, or ESA, comes into play for activities that involve some form of federal decision making, such as federal permitting. In that case the decision-making agency has to determine whether an activity has the potential to affect a protected species and, if so, must contact the National Marine Fisheries Service or the Fish and Wildlife Service for an informal consultation. The informal consultation will have one of three outcomes: a finding of no effect on the species; a finding of a possible effect, but with no likely adverse impact; or a finding of the potential for an adverse effect.

A finding of a potential adverse effect will lead to a formal consultation and the preparation of a biological opinion for the proposed activity. The biological opinion will include a set of conditions known as "reasonable and prudent measures" imposed on the activity to avoid harmful impacts on the species. The opinion will also include a decision of "jeopardy" or "no jeopardy" for the species, with "no jeopardy" being by far the most common decision, Brandt-Erichsen said. A finding of "jeopardy" means that the agency thinks that the activity will have a real adverse effect on the ability of the species to survive and recover, he said.

Critical habitat

A critical habit designation is normally made in conjunction with an ESA listing and one of the issues that plays into a "jeopardy" decision is the possibility of "adverse modification" of that habitat. The agencies used to have a definition of adverse habitat modification but, following rejection of that definition by some courts, the agencies have dropped the definition and have meantime reverted to the use of a rather vaguely worded working definition. The lack of a precise definition creates opportunities for mischief, Brandt-Erichsen said.

To protect against a citizen lawsuit or to influence the formulation of mitigation measures, it is possible for people to take pre-emptive action, even in a situation where a federal decision is not required, by voluntarily requesting a consultation under section 10 of the ESA. An action under section 10 will result in the negotiation of a habitat conservation plan, spelling out the means of mitigating adverse impacts on the species and considering alternative ways of carrying out a project, Brandt-Erichsen said.

And when a species is being considered for listing it is possible to negotiate a candidate conservation agreement, committing to conservation measures in return for protection against new conservation requirements at a later date, he said.

Litigation

However, the main threat to projects posed by the ESA is the possibility of litigation and an associated injunction against project activities, Brandt-Erichsen said.

In fact, although people tend to worry about the ESA placing new, onerous requirements on projects, environmental issues such as oil spill risks are already covered by statutes such as the Clean Water Act. And, although an ESA biological opinion may spell out mitigation measures for preventing an oil spill from an oil development activity, for example, those measures should be the same as the mitigation measures required by other statutes, Brandt-Erichsen said.

Cook Inlet belugas

As an example of an ESA listing in operation, Brandt-Erichsen cited the listing of the Cook Inlet beluga whales. So far, the National Marine Fisheries Service has issued two formal beluga whale biological opinions, one for the expansion of the Port of Anchorage and the other for a proposed Knik Arm crossing, he said. Both of these biological opinions made "no jeopardy" findings and found no likelihood of adverse critical habitat modifications. The agency is currently preparing a biological opinion for planned Cook Inlet seismic surveys by Apache Corp., he said.

There has been much debate over the extensive area of critical habitat designation for the Cook Inlet beluga whales. However, the National Marine Fisheries Service has argued that the main impact of the beluga listing on development activities stems from the listing itself rather than the habitat designation — that is a position that the courts have upheld, Brandt-Erichsen said. However, the critical habitat elements for the Cook Inlet belugas — clean water and unrestricted passage between different habitat areas, for example — are very general in nature, making these habitat elements potential focal points for litigation, he said. ●

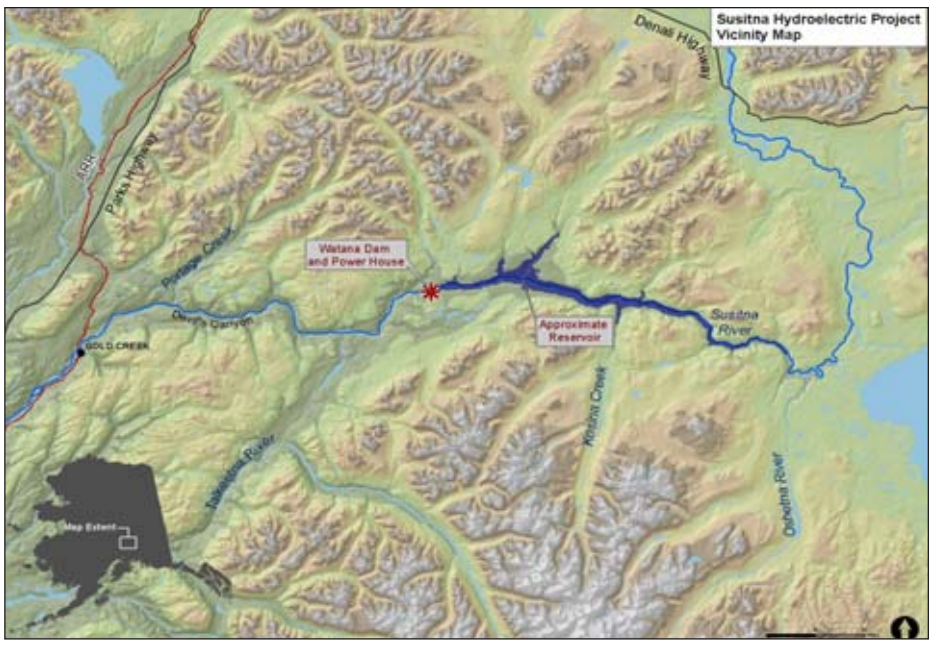
Contact Alan Bailey
at abailey@petroleumnews.com

• ALTERNATIVE ENERGY

Susitna hydro pre-app goes to FERC

AEA starts the nearly four-year formal license application process for a major hydroelectric facility at Watana on the Susitna River

ALASKA ENERGY AUTHORITY



The proposed Watana Dam would be on the Susitna River in remote country south of the Alaska Range. An access road to the dam site would either run west to meet the Alaska Railroad and Gold Creek, or Chulitna to the north, or it would run north from the dam to intersect with the Denali Highway.

By ALAN BAILEY
Petroleum News

The Alaska Energy Authority has taken the next step towards the construction of a major hydroelectric power plant at Watana on the upper Susitna River by filing a license pre-application document with the Federal Energy Regulatory Commission. The authority will eventually need a FERC license to build the power plant and put it into operation — the pre-application marks the beginning of the formal licensing process, a process that includes a series of studies into the potential environmental impacts of the hydropower facility.

Project schedule

AEA anticipates completing the required studies and submitting a license application by mid-September 2015. The project plan for the facility also includes site surveys and preliminary engineering work, to be carried out in 2012, with an economic evaluation and financing plan to be developed early in 2013. A final design for the facility should be completed in 2016 and, assuming that a FERC license is forthcoming in 2017, AEA anticipates system construction and startup completing at the end of 2023.

With an installed capacity of 600 megawatts, the facility would represent a major diversification away from the region's current high level of dependence on natural gas-fueled power stations. The facility would also become a major factor in achieving a state policy that at least 50 percent of Alaska's electricity should come from renewable energy sources by 2025.

The facility would produce an average of about 250 megawatts of guaranteed power between November and April, but with power output perhaps varying briefly between 100 megawatts and 500 megawatts, the pre-application document says.

"This is an important day, not only for the Susitna-Watana hydroelectric project, but for long-term and stable electrical energy for generations of Alaskans," said AEA Board Chairman Hugh Short on Dec. 29 when announcing the filing of the pre-application document. "This project is part of a larger energy picture that will serve the entire Railbelt while moving Alaska toward its renewable energy goals."

700 feet high

The pre-application document says that the design of the Watana dam is still being evaluated, but that the dam would likely stand 700 feet above its foundation, with a crest length of about 2,700 feet, creating a 39-mile long reservoir. The use of roller-compacted concrete is the most likely construction scenario, the document says. The project site is about 90 river-miles northeast of the community of Talkeetna.

Three alternative routes are being considered for access roads to the hydro facility. One alternative would run west from the facility, staying north of the Susitna River, and meeting the Alaska Railroad and the Fairbanks to Anchorage electrical transmission intertie near Chulitna. The second alternative would also run west, but keeping south of the river and meeting the railroad and intertie near Gold Creek. The third alternative would run north from the facility to connect with the Denali Highway, to the south of the Alaska Range.

Power transmission lines connecting the facility with the Fairbanks to Anchorage intertie, and hence to the Alaska Railbelt power grid, would approximately follow one or more access road routes. A transmission line following the route to the north would continue along the route of the Denali Highway, to connect with the intertie at Cantwell on the Parks Highway.

600 megawatts

Although the system design currently envisages an installed capacity of 600 megawatts, using three generators, it is possible that the designed capacity could be increased to 800 megawatts by the time that the final FERC license application is submitted, the pre-application document says. Once the system goes into operation, the topping up and drawing down of the system's reservoir would be timed to meet Railbelt load following requirements, with peak loads occurring during the winter months. The facility would produce an average of about 250 megawatts of guaranteed power between November and April, but with power output perhaps varying briefly between 100 megawatts and 500 megawatts, the pre-application document says.

Study topics

Likely topics for environmental studies

see **SUSITNA HYDRO** *page 12*

• NATURAL GAS

Gas line needs multimillion-dollar review

Alaska natural gas pipeline requires major environmental analysis; FERC lead agency; could also lead EIS for smaller line for LNG

By BILL WHITE

Researcher/writer for the Office of the Federal Coordinator

Before construction can begin, the proposed Alaska natural gas pipeline must undergo a multimillion-dollar analysis of how the project could change the physical, economic, social and cultural environments along the line's path through the state.

The Federal Energy Regulatory Commission already has started the environmental review of the $32 billion to $41 billion project that would pipe 4.5 billion cubic feet a day of North Slope natural gas through Canada to the Lower 48.

BILL WHITE

FERC also could lead the environmental review for a smaller pipeline and liquefied natural gas export project from Alaska if an LNG proposal surfaces.

For the pipeline project through Canada, the project sponsor — a partnership of TransCanada and ExxonMobil called the Alaska Pipeline Project — has prepared but not yet released an estimated 4,500 pages of material that would serve as background data for the environmental impact statement FERC plans. This material, in 11 draft documents called "resource reports," is expected to minutely document and discuss the project's potential impact on soils, vegetation, streams, lakes, wetlands, water quality, wildlife, fish and other resources along the 803-mile pipeline corridor from the Point Thomson field to Prudhoe Bay to the Canadian border.

Why not release the draft reports? Tony Palmer, the TransCanada executive who chairs the APP management committee, said that his partnership recently started discussions with the main North Slope producers about an LNG project in response to Alaska Gov. Sean Parnell's call this fall for the producers to reconsider the LNG export option. The partnership decided to wait to release the resource reports while the discussions continue, even though the reports "are complete and ready to be filed," he told Alaska public radio.

Once APP files the draft resource reports, FERC plans to hold public meetings in urban and rural Alaska to help define what the project's environmental impact statement will encompass.

Last August, FERC formally launched the environmental review of the project to the Canadian border. The review could result in a completed EIS as soon as mid-2014, with a FERC decision on whether to approve the project a couple of months later.

As this review progresses, scores of people from Alaska to Texas to Washington, D.C., will be immersed in trying to make sure they and the public grasp the environmental impacts of what would be the most expensive private sector construction project in North American history.

All this effort stems from a monumental 42-year-old federal law that some have called an environmental Magna Carta. That law, the National Environmental Policy Act of 1969, or NEPA, requires federal agencies to understand and disclose the environmental consequences of their decisions. The term "environment impact statement" is derived from NEPA's language.

ALASKA PIPELINE PROJECT

Wetlands along the proposed pipeline route south of Delta Junction are checked during summer 2011.

NEPA has spawned a massive industry of government workers, consultants, lawyers and others, and a massive backlash from business groups that say the law can entail an overkill of analysis that adds cost and delay to projects — for example, NEPA lawsuits helped stall Alaska oil pipeline construction for a time in the early 1970s.

NEPA arose at a time when V8 sedans burning leaded gasoline populated the nation's roads and it dawned on Americans that the orange haze that made sunsets spectacular might have drawbacks. Less than four months after NEPA became law on Jan. 1, 1970, concerned citizens rallied in the first Earth Day, an event many consider the birth of the modern environmental movement.

A gelling of environmental policy

The 1950s and 1960s provided many catalysts for NEPA, including an emerging environmental movement, the damming of glorious western canyons, a catastrophic oil spill off California's coast and the surprises residents got when they learned freeways would be bulldozed through their neighborhoods.

Congress was in the mood to redress what some perceived as past wrongs, with legislation not only about the environment but separate bills on civil rights and poverty. Regarding the environment, Congress passed the Wilderness Act in 1964, the Wild and Scenic Rivers Act in 1968 and, soon after writing NEPA, the Clean Air Act and the Clean Water Act.

For NEPA, a consequential event occurred in 1968, when the Senate Interior and Insular Affairs Committee Chairman Henry "Scoop" Jackson learned the Interior Department and Park Service were acquiring land for Everglades National Park while the Army Corps of Engineers was planning to drain Everglades water to create farm land. Meanwhile, the Transportation Department was proposing to build the world's largest airport six miles from the park. Were these agencies talking with each other about their conflicting plans? Jackson asked. Nope. (The airport project died, in part due to efforts of then-Interior Secretary Wally Hickel, a former Alaska governor.)

Jackson, D-Wash., introduced the bill that became NEPA in February 1969, amid public furor over a massive oil spill offshore Santa Barbara, Calif., that occurred exactly three weeks earlier. Jackson's ideas were melded with those of Sen. Edmund Muskie, D-Maine, and Rep. John Dingell, D-Mich., into the new law. President Richard Nixon signed it on Jan. 1, 1970, while declaring: "It is particularly fitting that my first official act in this new decade is to approve the National

see **GAS LINE REVIEW** *page 13*

FINANCE & ECONOMY

Alyeska relocating to new Anchorage digs

Alyeska Pipeline Service Co. is moving its Anchorage offices, but the firm's new home isn't far away.

The operator of the 800-mile trans-Alaska oil pipeline is leaving the BP Exploration (Alaska) Inc. office tower and moving into a new building located just south of 36th Avenue between C Street and Arctic Boulevard.

The BP tower and the new building are both in Anchorage's Midtown district.

Alyeska is vacating several floors in the BP building, where the pipeline company has leased space since 2003.

The new office building, known as Centerpoint West and developed by JL Properties Inc. at a cost of $70 million, "offers 200,000 square feet of premium office space," said an Alyeska press release.

The eight-story building was completed in early 2010 using Leadership in Energy and Environmental Design specifications — the first commercial building in Alaska with LEED Gold certification, the press release said.

Alyeska expects to wrap up its move in mid-February.

The physical address for the new Alyeska headquarters is 3700 Centerpoint Drive, Anchorage, AK 99503.

Alyeska's mailing address will remain P.O. Box 196660, Anchorage, AK 99519-6660.

All of Alyeska's Anchorage phone numbers and its website also will stay the same.

BP implications

Alyeska is a consortium of five energy companies that runs the pipeline. BP is the major owner at 46.9 percent. The other owners are ConocoPhillips, ExxonMobil, Koch Industries and Chevron.

Alyeska's move has implications for BP, which has some staff not only in the Midtown tower but in other locations around Anchorage.

"One of our goals with this change is to base more of our Anchorage teams in the headquarters building," Steve Rinehart, BP's Anchorage spokesman, told Petroleum News in a Jan. 3 email.

Alyeska also has offices in Fairbanks and Valdez and has staff stationed along the line, from Prudhoe Bay to Prince William Sound, working as operations technicians, maintenance workers, safety specialists, security officers, spill response coordinators and in other positions.

For more information on the move, contact Alyeska at anchqmove@alyeska-pipeline.com or (907) 787-8870.

—WESLEY LOY

ALASKA ENERGY AUTHORITY

The proposed Watana Dam would stand about 700 feet high and create a reservoir 39 miles in length.

continued from page 10

SUSITNA HYDRO

to be conducted in preparation for the FERC license application include impacts on water resources and water quality; impacts on fish distribution and abundance; impacts on wildlife and botanical resources; subsistence resource impacts; recreational land use issues; issues relating to cultural resources; and potential socioeconomic and transportation impacts in the region.

AEA says that it is committed to the development of plans for the protection and enhancement of environmental resources.

To be able to view the planned project site in summer conditions, FERC staff visited the site on Aug. 29 2011 — FERC now plans to hold scoping meetings in March for an assessment of the project under the National Environmental Policy Act, or NEPA. That scoping will ultimately lead to the preparation of an environmental impact statement, under NEPA, starting after AEA applies for the FERC license and needing to be completed before FERC can issue the license.

AEA has established a project website at www.susitna-watanahydro.org. This website acts as a distribution center for key project documents — the schedule for the FERC scoping meetings will be published on the site. ●

Contact Alan Bailey
at abailey@petroleumnews.com

continued from page 11

GAS LINE REVIEW

Environmental Policy Act."

A key feature arising from the Everglades bungle: The lead federal agency must work with and rely on the expertise of other agencies before making a decision on a project.

NEPA: Look before you leap

NEPA serves up some lofty language about how government and citizens should behave toward the planet:

• Congress recognizes "the critical importance of restoring and maintaining environmental quality to the overall welfare and development of man."

• It is federal policy "to create and maintain conditions under which man and nature can exist in productive harmony."

• Each generation has a responsibility "as trustee of the environment for succeeding generations."

• The federal government has a responsibility "to achieve a balance between population and resource use which will permit high standards of living and a wide sharing of life's amenities."

This language comes from NEPA's Section 101 — a kind of environmental manifesto.

But the meat of NEPA is found in Section 102.

The guiding principle of this section is that federal agencies will make better decisions if they consider as well as reveal to the public the environmental consequences of their decisions.

Agencies are to give environmental effects equal footing with the economic, technical and social considerations they had used previously in making decisions. The lead agency for a project should tap the expertise of other federal agencies before deciding to authorize a project.

For "major federal actions significantly affecting the quality of the human environment," the agency must prepare "a detailed statement" on the "environmental impact of the proposed action." This is the language in federal law that birthed environmental impact statements.

The agency must study alternatives to the proposal and, most important, it must involve the public.

How NEPA works

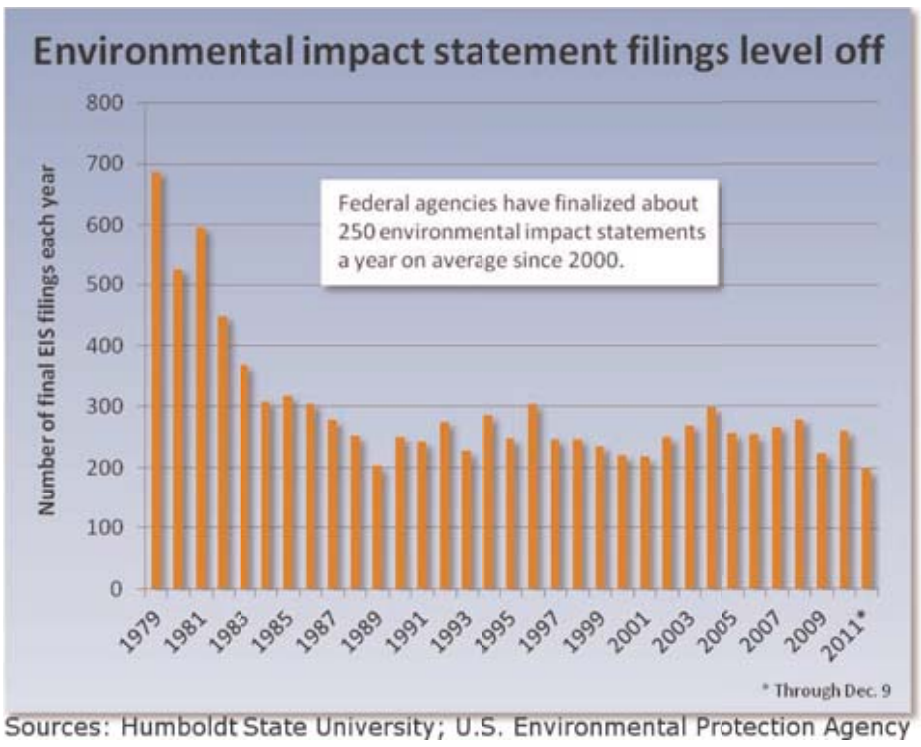
The 1969 law also created the Council on Environmental Quality under the president. The council's mission: "Formulate and recommend national policies to promote the improvement of the quality of the environment."

In 1978, that council issued the first NEPA regulations. The regulations flesh out how NEPA will work, from how extensive the environmental review should be to how to involve the public.

HOW EXTENSIVE A REVIEW — The regulations let agencies follow several paths in considering an action's environmental effects.

The shortest path is called a "categorical exclusion." Agencies take this path for routine actions that have no significant environmental impact. This path sidesteps the full-scale NEPA process. FERC generally declares categorical exclusions for decisions involving rate reviews, sale or transportation of gas that involves no construction, routine installation of meters in a pipeline right of way and abandonment of short segments of minor pipelines if site restoration occurs.

A middle path involves doing an "environmental assessment." This term does not appear in the NEPA text but is in the NEPA regulations. Agencies do an assessment to clarify the magnitude of the potential environmental harm and determine whether a full-blown environmental impact statement is necessary.



Sources: Humboldt State University; U.S. Environmental Protection Agency

Environmental assessments can result in a document called a "finding of no significant impact," which means no extensive EIS is needed and the environmental review is finished. Sometimes this finding occurs after the project backer agrees to changes that minimize or mitigate environmental harm.

The other possible outcome of environmental assessments: A decision to do an EIS.

Federal agencies issue far more assessments than impact statements — tens of thousands of assessments annually vs. a couple hundred impact statements.

Sometimes an agency will skip the environmental assessment and leap right into an EIS because it's clear the project is so substantial that it will need one.

An EIS, of course, is the longest, most complicated path, typically involving years of work and costing millions of dollars. The Alaska gas pipeline project to Canada is required to have an EIS.

LEAD AGENCY, COOPERATING AGENCY — An agency with major responsibility for the project will take the lead in studying environmental impacts. Other agencies, known as cooperating agencies, will participate and use the EIS studies and analyses when making their own decisions about the project.

For the Alaska gas pipeline to Canada, Congress designated the Federal Energy Regulatory Commission as the lead agency. So far, nine federal agencies and one state of Alaska office have signed on as cooperating agencies. These are the Bureau of Land Management, Fish and Wildlife Service, Environmental Protection Agency, Army Corps of

see **GAS LINE REVIEW** *page 14*

continued from page 13

GAS LINE REVIEW

Engineers, Pipeline and Hazardous Materials Safety Administration, Coast Guard, Air Force, U.S. Geological Survey, Office of the Federal Coordinator, and the Alaska State Pipeline Coordinator's Office.

Many cooperating agencies oversee aspects of a project. For example, if the Alaska gas pipeline is built:

• FERC will authorize construction and operation.

• BLM will OK use of federal land for the pipeline route.

• Fish and Wildlife Service, in consultation with FERC, will ensure construction doesn't worsen the status of threatened or endangered species, migratory birds, and bald and golden eagles.

• The pipeline safety office will ensure the pipeline itself remains safe if the builder diverges from federal standards in the belief that its pipe coating or spacing of sleeves to stop cracks exceed the standards.

• The Army Corps of Engineers will authorize some river crossings and impacts to wetlands.

ALASKA GAS PIPELINE PROJECT OFFICE

The Alaska Pipeline Project recently began testing pipe in Canada for use in the Alaska natural gas pipeline.

FERC must consider the information needs of the cooperating agencies, because the cooperating agencies must rely on the FERC-prepared environmental impact statement for their separate, individual decisions on the project. For example, one agency might want the environmental effects examined within two miles of a certain point along the pipeline route while another agency needs to look within five miles of that point. The lead agency will make sure five miles are examined to meet both of these cooperating agencies' needs.

PUBLIC INVOLVEMENT — The regulations say agencies must "encourage and facilitate public involvement in decisions which affect the quality of the human environment." The rules designate certain points in the NEPA process where public outreach must occur.

First comes "scoping." During this time, the lead agency holds public meetings to ensure the EIS will include issues that people and other agencies believe are important. For the Alaska gas pipeline project to Canada, FERC plans to hold the public meetings after receiving the 11 draft resource reports from APP, giving the public and other government agencies time to digest the data and analysis already compiled.

The goal of scoping meetings is to identify what environmental effects will be studied. The public and other agencies also can comment to the lead agency outside of the scoping meetings.

In addition, formal public outreach occurs after an agency drafts its EIS. The lead agency typically circulates the document to anyone who requested a copy, then responds to the feedback when finalizing the EIS.

When FERC formally notified the public in August 2011 that it will conduct an EIS for the Alaska pipeline project to Canada and hold scoping meetings, it published the notice in the Federal Register and sent it directly to over 2,200 people and organizations that told FERC they want to be informed about the project.

Separately, FERC posts documents, comments, decisions and other material for the Alaska project on its website under Docket Number PF09-11. Once the pipeline sponsor files its formal application, required in October 2012 under its cost-reimbursement contract with the state, FERC will assign a new docket number. FERC's site is set up so that an individual can be notified automatically when a docket contains anything new.

NEPA for the Alaska project

NEPA and the Council on Environmental Quality's regulations are two of the four federal documents controlling the content and timing of the Alaska-Canada pipeline's environmental review.

The other documents are FERC's own regulations about NEPA and the Alaska Natural Gas Pipeline Act of 2004.

FERC'S REGULATIONS — These were mentioned above briefly in noting when FERC skips a robust NEPA review and issues a categorical exclusion instead.

Beyond this, FERC regulations spell out advance work required of anyone wanting to build a gas pipeline. When applying for FERC permission to build and operate the line, the sponsor must submit detailed documentation of the route's environment and potential harm.

FERC calls these documents "resource reports." FERC regulations spell out what the reports must cover, and FERC will reject an application if the resource report documentation is too flimsy.

TransCanada and ExxonMobil, sponsor of the Alaska gas line project, have spent tens of millions of dollars in recent years

see **GAS LINE REVIEW** *page 15*

The 11 resource reports

- **Resource Report 1 –** Detailed project description, maps
- **Resource Report 2 –** Wetlands, rivers, streams, lakes, water uses and quality
- **Resource Report 3 –** Fish, wildlife, vegetation, endangered species
- **Resource Report 4 –** Cultural resources, archeology
- **Resource Report 5 –** Socioeconomics, housing, job and government impacts
- **Resource Report 6 –** Geological resources, hazards
- **Resource Report 7 –** Soils, potential erosion
- **Resource Report 8 –** Current land use, recreation, esthetics
- **Resource Report 9 –** Air and noise impacts
- **Resource Report 10 –** Project alternatives
- **Resource Report 11 –** Pipeline system reliability, safety

continued from page 14

GAS LINE REVIEW

compiling the data within the 11 draft resource reports. Each report concerns a different aspect of the environment, from soils and vegetation to wildlife counts, earthquake faults, archeological sites and even how much Alaska's population could grow if the project is built. The Council on Environmental Quality has termed analyzing alternatives the "heart of the EIS," and resource report No. 10 is to focus on alternatives.

FERC, the cooperating agencies and the public will vet the draft resource reports after the reports get submitted. FERC likely will ask the sponsor for additional information. TransCanada and ExxonMobil face a deadline to finalize the reports before they file in October 2012 for a FERC certificate to build and operate the pipeline.

The resource reports will serve as a foundation for the EIS. FERC staff and its contractors, working with the cooperating agencies, plan to verify the information within the reports and do additional environmental research in preparing the EIS.

FERC regulations build in measures to ease environmental impacts, such as requiring projects to maximize use of existing rights of way and controlling how new rights of way are cleared. FERC regs also limit the alternatives it studies to those that offer a significant environmental advantage, are economically feasible and meet the project objectives within the same time frame as the proposed project. Alternatives considered must include different pipeline routes, energy conservation and rejecting the project.

THE ALASKA NATURAL GAS PIPELINE ACT — This 2004 federal law addresses the NEPA chain of events in several ways.

NEPA documents circa 2003

Small environmental assessments
10-30 Pages
2-8 weeks Time to complete
$5,000-$20,000 Cost

Large environmental assessments
(More controversial, higher-profile projects)
50-200+ Pages
39-78 weeks Time to complete
$50,000-$200,000 Cost

Environmental impact statements
200-2,000+ Pages
1-6 years Time to complete
$250,000-$2 million Cost

Source: The NEPA Task Force Report to the Council on Environmental Quality "Modernizing NEPA Implementation" September 2003. http://ceq.hss.doe.gov/ntf/report/totaldoc.html

First, it mandates an environmental impact statement for the project to pipe Alaska gas through Canada to the Lower 48. No categorical exclusion or environmental assessment allowed. The project is "a major Federal action significantly affecting the quality of the human environment," the law states.

Second, the law names FERC as the lead agency for the EIS. It also requires other federal agencies with jurisdiction over the gas pipeline project to cooperate with FERC and use the impact statement for their own approvals.

Third, it sets deadlines. FERC has 12 months to draft an environmental impact statement after determining the application for a certificate is complete. Then it has six more months to finalize the EIS. If the application is received in October 2012, and assuming FERC accepts it then as complete, the draft EIS could be done in fall 2013 and the final EIS in spring 2014.

Goal of 'excellent action'

The final NEPA step is called a "record of decision" that states what the agency has decided about the project. FERC takes this step for pipelines when it issues or denies a certificate to a project sponsor to build and operate the line. When FERC awards a certificate, the commission often requires the pipeline builder to mitigate some environmental harm the EIS identified.

An important aspect of NEPA is that it doesn't require an agency to decide in favor of the least environmentally harmful option for a project. NEPA merely requires that the agency understand the project's environmental impacts, consider alternatives that might be less harmful, including the option of rejecting the project, and disclose what it learns to the public.

Then the agency can decide whether or not to authorize the project.

Council on Environmental Quality regulations say this about the law:

"NEPA's purpose is not to generate paperwork — even excellent paperwork — but to foster excellent action."

The purity of that ideal is not always achieved in practice.

For many years after NEPA's enactment, each new EIS from an agency seemed to trump the agency's last EIS in volume.

A problem is that the law calls for examining significant impacts of major federal actions without sharply defining "significant" or "major." Many lawsuits have successfully challenged NEPA reviews for lack of thoroughness. So agencies have tended to pile on the analysis to blunt challenges.

A 1997 NEPA critique by the Council on Environmental Quality found that

see **GAS LINE REVIEW** *page 17*

EXPLORATION & PRODUCTION

Deep Gulf drilling thrives after BP spill

By early this year more rigs will be working in deepwater in the Gulf of Mexico than before the Deepwater Horizon explosion in 2010

By JONATHAN FAHEY
Associated Press Energy Writer

Two hundred miles off the coast of Texas, ribbons of pipe are reaching for oil and natural gas deeper below the ocean's surface than ever before.

These pipes, which run nearly two miles deep, are connected to a floating Shell platform that is so remote they named it Perdido, which means "lost" in Spanish. What attracted Shell to this location in Alaminos Canyon block 857 is a geologic formation found throughout the Gulf of Mexico that may contain enough oil to satisfy U.S. demand for two years.

While Perdido is isolated, it isn't alone. Across the Gulf, energy companies are probing dozens of new deepwater fields thanks to high oil prices and technological advances that finally make it possible to tap them.

The newfound oil will not do much to lower global oil prices. But together with increased production from onshore U.S. fields and slowing domestic demand for gasoline, it could help reduce U.S. oil imports by more than half over the next decade.

By early 2012, there will be 40 deepwater rigs in the Gulf, up from 37 before the BP spill, according to Cinnamon Odell of ODS-Petrodata.

Drilling had been halted

Eighteen months ago, such a flurry of activity in the Gulf seemed unlikely. The Obama administration halted drilling and stopped issuing new permits after the explosion of a BP well killed 11 workers and caused the largest oil spill in U.S. history.

But the drilling moratorium was eventually lifted and the Obama administration issued the first new drilling permit in March. Now the Gulf is humming again and oil executives describe it as the world's best place to drill.

"In the short term and the medium term, it's clearly the Gulf of Mexico," says Matthais Bichsel, a Royal Dutch Shell PLC board member who is in charge of all of the company's new projects and technology.

By early 2012 there will be more rigs in the Gulf designed to drill in its "deep water" — defined as 2,000 feet or deeper — than before the spill.

In November, Perdido began pumping oil from a field called Tobago; the well begins 9,627 feet below the surface of the Gulf. No other well on the globe produces oil in deeper water and that's about as deep as the Gulf gets. For drillers, that means the entire Gulf is now within reach.

"We are at the point where ... depth is not the primary issue anymore," says Marvin Odum, the head of Royal Dutch Shell's drilling unit in the Americas. "I do not worry that there is something in the Gulf that we cannot develop ... if we can find it."

Perdido in 8,000 feet of water

From a distance, Perdido looks like an erector set perched on an aluminum can. This can, or "spar," is a 500-foot-tall steel cylinder that sits mostly underwater, serving as a base for the equipment and living quarters above. It is stuffed with iron ore to lower its center of gravity, keeping the whole operation from bobbing in the water like a cork. The spar is tethered to the sea floor 8,000 feet below with ropes and chains.

Oil and natural gas are pumped to Perdido from nearby wells drilled by an onboard rig and from faraway wells drilled by satellite rigs. Water and other impurities are then removed from the oil and gas, which gets sent hundreds of miles through an undersea pipeline to terminals and refineries along the Gulf coast.

Perdido, which pumps the equivalent of 60,000 barrels of oil and natural gas a day, will eventually yield 100,000 barrels per day from 35 wells in a 30-mile radius, according to Shell. It will likely produce oil for decades — in all, as much as 360 million barrels of oil and 750 billion cubic feet of natural gas, according to Wood Mackenzie.

As global oil demand climbs past 89 million barrels a day and traditional onshore and shallow water fields are depleted, the deep waters of the Gulf and off the coasts of South America, West Africa and Australia are playing an increasingly important role.

Volumes from deepwater growing

In 2000, 1.5 million barrels of oil per day were produced from deepwater fields around the globe, or 2 percent of global production. In 2011, that number grew to 5.5 million barrels, or 6 percent of global production. By 2020, deepwater oil will account for 9 percent, according to IHS CERA.

The Gulf is attractive for many reasons. Its oil fields are enormous; it straddles the world's biggest consumer of oil; it's in a politically stable part of the world; and drillers can easily tap into a vast network of pipelines and refineries. Also, despite industry complaints, the cost of royalties, taxes and regulation in the U.S. are among the lowest in the world.

"Everybody wants to be there," says Mohammad Rahman, the lead Gulf analyst for Wood Mackenzie.

By early 2012, there will be 40 deepwater rigs in the Gulf, up from 37 before the BP spill, according to Cinnamon Odell of ODS-Petrodata. BP received its first permit to drill in late October.

The Gulf produces an average of 1.5 million barrels of oil per day, according to Wood Mackenzie. That's 27 percent of U.S. output and 8 percent of U.S. demand.

Major deepwater finds

Thanks to more accurate imaging

see **DEEP GULF DRILLING** *page 17*

continued from page 16

DEEP GULF DRILLING

technologies, drillers are able to see under geologic formations that used to confound geologists. In June, Exxon Mobil Corp. said it found 700 million barrels of oil — one of the biggest discoveries in the Gulf in last decade. In September, Chevron and BP also announced major finds, thought to be in the hundreds of millions of barrels of oil.

Many of the Gulf's recent discoveries are in a geologic formation known as the Lower Tertiary, formed between 23 million and 65 million years ago. Perdido, which is operated by Shell and owned jointly by Shell, Chevron and BP, is the first to produce oil from this formation. Analysts say it could hold 15 billion barrels of oil.

As the BP disaster made clear, drilling in deep water presents difficulties and dangers. In November a Chevron well in the deep waters off of Brazil ruptured and spilled 2,400 barrels of oil into the Atlantic after Chevron underestimated the pressure of the oil field it was tapping.

Perdido only recently reached its monthly production target after a year of operation because of difficulties getting oil and gas from the seabed to the platform. New devices designed to separate oil and gas on the sea floor have not performed as well as Shell hoped. It has taken months of adjustments made by underwater robots and other equipment on the platform to fix the problems.

Challenges like this have helped push the average cost of producing oil in the deepwater Gulf to $60 a barrel, according to IHS CERA, near the highest level ever. But with oil close to $100 a barrel, the expense is well worth it.

After all 35 wells are drilled for Perdido, its owners will likely have spent $6.2 billion on the project, according to Wood Mackenzie. But along with the risks, the Gulf offers great rewards: Perdido could ultimately generate $39 billion in revenue and $16 billion in profits. ●

continued from page 8

KEYSTONE DISPUTE

Rep. Fred Upton, chairman of the House Energy and Commerce Committee.

Opponents call the West Coast option farfetched, noting that Canadian regulators have announced a one-year delay for a similar project that would carry tar sands oil to British Columbia, on Canada's western coast.

Unions are watching closely. Unemployment in construction is far higher than other industries, with more than 1.1 million construction workers jobless, said Brent Bookers, director of construction at the Laborers' International Union of North America.

"For many members of the Laborers, this project is not just a pipeline, it is a lifeline," Bookers said.

Roger Toussaint, international vice president of the Transport Workers Union, opposes the pipeline.

"The dangers of the pipeline are compelling, and no one should believe the claims of either the Republican leadership or the energy companies, with respect to the project being shovel ready or with respect to the number of jobs it's going to produce," he said. ●

—Associated Press writer Grant Schulte in Lincoln, Nebraska, contributed to this report.

continued from page 15

GAS LINE REVIEW

"frequently NEPA takes too long and costs too much, agencies make decisions before hearing from the public, documents are too long and technical for many people to use, and training for agency officials at times is inadequate."

Further, no one really knows how much better the environment is as a result of the law, or whether the benefit is worth the cost.

A 2006 U.S. House Natural Resources Committee task force report noted the thinness of data on NEPA-related costs. Among other recommendations, it called for the Council on Environmental Quality to determine the costs of environmental reviews and recommend cost caps to Congress. In part to contain costs, the report endorsed an 18-month time limit for environmental impact statements and a nine-month limit for assessments. "Sensible timeframes will make for better federal decisions," the report said.

Other critiques note that agencies do a poor job making sure the mitigation they order for a project actually occurs so that the environmental damage is avoided or reduced.

The Council on Environmental Quality issues regular guidance to agencies on how to comply with NEPA. In 2011 it issued guidance calling for completing environmental reviews more quickly and monitoring required mitigation more rigorously.

Despite the criticism, few dispute that because of NEPA the government has amassed a treasure trove of baseline information on the status of the nation's environment.

An important aspect of NEPA is that it doesn't require an agency to decide in favor of the least environmentally harmful option for a project. NEPA merely requires that the agency understand the project's environmental impacts, consider alternatives that might be less harmful, including the option of rejecting the project, and disclose what it learns to the public.

And nearly everyone agrees NEPA has brought meaningful change to federal decision making.

An often-cited statement from the council's 1997 critique sums up this sentiment:

"NEPA's most enduring legacy is as a framework for collaboration between federal agencies and those who will bear the environmental, social and economic impacts of their decisions. ... (A)gencies today are more likely to consider the views of those who live and work in the surrounding community and others during the decision-making process." ●

Editor's note: This is a reprint from the Office of the Federal Coordinator, Alaska Natural Gas Transportation Projects, online at www.arcticgas.gov/Pipeline-project-would-get-multimillion-dollar-environmental-review.

EXPLORATION & PRODUCTION

US drilling rig count down by 1 to 2,007

The number of rigs actively exploring for oil and natural gas in the U.S. decreased by one the last week of December to 2,007.

Houston-based drilling product provider Baker Hughes Inc. reported Dec. 29 that 1,193 rigs were exploring for oil and 809 for natural gas. Five were listed as miscellaneous. A year ago this week Baker Hughes reported 1,694 active rigs.

Of the major oil- and gas-producing states, Pennsylvania added four rigs and Louisiana, New Mexico, North Dakota and West Virginia each added one.

Arkansas declined by four rigs, Texas lost three and Alaska and Oklahoma each dropped one. California, Colorado and Wyoming were unchanged.

The rig count peaked at 4,530 in 1981. A low of 488 was recorded in 1999.

—ASSOCIATED PRESS

Total makes $2.3B bet on Chesapeake shale

Chesapeake Energy Corp. says it has started a joint venture with a unit of French energy company Total SA for oil drilling in Ohio's Utica Shale.

Total will pay Chesapeake and a smaller partner $2.32 billion in a deal that adds U.S. oil and gas assets that have become a common target of overseas oil companies.

The deal announced Jan. 3 calls for Total to pay Chesapeake and a smaller partner $2.32 billion.

In exchange, Total gets a 25 percent share in 619,000 acres in 10 counties in Ohio. Chesapeake is getting $610 million up front. The rest of its compensation will be in exchange for drilling through 2014.

Most of the land is owned by Chesapeake, which will operate the joint venture.

The land in the Utica Shale is especially valuable because it is thought to contain a large amount of oil, as opposed to the natural gas more common in other shale.

Chesapeake is getting $610 million up front. The rest of its compensation will be in exchange for drilling through 2014.

Chesapeake announced plans for the joint venture in November but did not identify its partner then.

—ASSOCIATED PRESS

FINANCE & ECONOMY

Oil price falls after supply increase

Oil prices slipped Jan. 5 after the government reported an unexpected increase in crude supplies and a 7 percent drop in petroleum demand. Natural gas prices also dropped as supplies remained well above the 5-year average.

In midday trading benchmark crude fell 41 cents to $102.81 per barrel in New York. Brent crude, which is used to price foreign oil varieties that are imported by U.S. refineries, rose 20 cents to $113.90 per barrel in London.

Prices dipped after government reports showed only tepid petroleum demand from consumers in recent weeks. The Energy Information Administration data came the same day as rosier economic readings showing fewer jobless claims and layoffs, strong retail sales and expansion in the service industry.

Petroleum demand has been sliding in the U.S. as drivers cut back on gasoline purchases. Gasoline consumption has dropped for months as retail prices rose. Pump prices rose 3 cents on Jan. 5 to a national average of $3.32 per gallon, the highest ever for this time of year.

The EIA said that oil supplies grew by 2.2 million barrels the week ending Dec. 30. Analysts expected them to shrink by 450,000 barrels, according to a survey by Platts, the energy-information arm of McGraw-Hill Cos.

—ASSOCIATED PRESS

continued from page 1

INSIDER

ConocoPhillips.

Although there was no alignment on LNG announced at the event, it was the first time since the passage of the Alaska Gasline Inducement Act that the three gas owners publicly admitted they were taking a close look at moving North Slope gas to tidewater in Southcentral Alaska for export as LNG to Asia.

Plus, a PN source said there was "significant progress" made on the Point Thomson settlement in the private meeting held before the luncheon, a meeting that included only Alaska Gov. Sean Parnell, Tillerson, Dudley and Mulva.

After the 1 hour and 40 minute meeting between the four chief executives, their staffs were invited into the room, including Alaska senior management for the oil companies and state commissioners and directors.

The four chief executives immediately explained the results of their meeting to their staffs so that there would be no mis-

see INSIDER page 21

FINANCE & ECONOMY

Escopeta chopped into three parts

Escopeta could soon be a tinier company

Over the second half of 2011, the Houston independent divided its assets between two companies. The subsidiary Escopeta Oil Co. LLC became Furie Operating Alaska LLC while the subsidiary Escopeta Oil of Alaska became Cornucopia Oil and Gas Co. LLC.

Although Furie and Cornucopia were not registered with the Alaska Division of Oil and Gas as of early December 2011, and are not listed as leaseholders, the names have been changed by the Alaska Division of Corporations, Business and Professional Licensing.

Escopeta Oil Co. holds some 33,745 acres and Escopeta Oil of Alaska holds some 79,930 acres. That acreage is in the Kitchen Lights unit and its surrounding un-unitized leases.

A third subsidiary, Escopeta Oil & Gas Corp., holds the four Hanna leases, a 6,880-acre onshore prospect on the west side of the Cook Inlet near the Ivan River unit.

—ERIC LIDJI

NATURAL GAS

FERC cancels Jan. 18 scoping meeting

Federal Energy Regulatory Commission staff said Jan. 4 that they have cancelled a public scoping meeting scheduled for Anchorage on Jan. 18 for the planned Alaska Pipeline Project.

A schedule of public scoping meetings in the project area was published Dec. 9.

On Dec. 19 TransCanada Alaska informed FERC of its intention to defer filing draft resource reports to allow time for discussions with the Alaska North Slope gas producers on a liquefied natural gas export option.

FERC said the resource reports will constitute the environmental component of TransCanada Alaska's application to FERC and are necessary for the public, the commission and other federal, tribal, state and local agencies to properly evaluate and comment on the project.

FERC said the remaining scheduled scoping meetings will also be cancelled if TransCanada Alaska fails to file the draft resource reports by the close of business Jan. 17.

FERC said a new schedule will be established when the resource reports are filed.

—PETROLEUM NEWS

EXPLORATION & PRODUCTION

Upper foothills open for tundra travel

The upper foothills area on Alaska's North Slope is now open for winter off-road tundra travel, the Department of Natural Resources' Division of Mining, Land and Water said Jan. 4.

The western coastal area opened in late December.

Targets for tundra travel opening are 9 inches of snow and a 23 degree Fahrenheit soil temperature at 30 centimeters in the foothills and 6 inches of snow and the same soil temperature in coastal areas.

The western coastal tundra opening area met the criteria earlier; the eastern coastal tundra area remains closed. The division said Dec. 23 that while soil temperatures were adequate for tundra opening at all eastern coastal monitoring stations, average snow depths ranged from 4.6 inches to 8.5 inches, with the 6-inch target snow depth met at only four of the six stations.

The division noted that openings apply only to operators with valid off-road vehicle travel permits to operate on state-owned lands on the North Slope.

The division also said that while overall snow cover is good, it may be thin in some areas and those areas should be avoided, or special construction methods used to protect the tundra surface.

For questions, call the division's Northern Region Land Section in Fairbanks at 907-451-2740.

—PETROLEUM NEWS

Petroleum news

Oil Patch Bits

Weston Solutions hires Hunter as oil & gas manager


ROBERT HUNTER

Weston Solutions Inc. said Dec. 28 that it has named Robert Hunter as its client oil and gas program manager for Alaska. Hunter has worked in Alaska since 1989, 13 years with BP and also as a consultant.

He received a B.A., in geology from the University of Montana in 1984 and an M.S. in geology from the University of Wyoming in 1986. Hunter helped champion BP Exploration (Alaska)-U.S. Department of Energy gas hydrate unconventional resource research and development beginning in 2001, leading to the 2007 stratigraphic test as published in the February 2011 issue of Journal of Marine and Petroleum Geology. His experience includes practical application of geosciences, environmental and engineering disciplines. Weston Solutions is a full-service environmental and consulting services firm headquartered in West Chester, Pa., with 50 Alaska-based employees and more than 1,800 staff in 46 offices around the globe. For over 50 years, Weston has provided integrated environmental, sustainable, property redevelopment, energy, and construction solutions to its clients large and small. For detailed information, visit www.westonsolutions.com.

ARRC names Dale Wade VP Business Development


DALE WADE

The Alaska Railroad Corp. said Jan. 3 that it has hired Dale Wade as vice president of Business Development.

The vice president of Business Development is responsible for ARRC Business Development Division activities including the marketing, promotion, sales, pricing, product design and implementation of freight and passenger services for the ARRC

Wade most recently served as the president of GoldStar Logistics Solutions. His past experience includes: managing director and transportation consultant for AFMS Transportation Management in Portland, Ore.; national account executive for FedEx Corp in Anchorage; and sales manager for CF Freight in Anchorage.

"Dale has the experience and the knowledge of the transportation industry that is so critically important to the Alaska Railroad," said ARRC President and CEO Chris Aadnesen. "His focus on teamwork and customer service will play a big part in our continuing mission to deliver the best service to the people of Alaska and our visitors."

Wade will be taking over the position from Steve Silverstein who retired at the end of 2011 after 10 years as vice president of Business Development and 16 years with the

see **OIL PATCH BITS** *page 21*

Companies involved in Alaska and northern Canada's oil and gas industry

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

continued from page 18

INSIDER

understandings.

The three oil company CEOs were in Alaska at the invitation of Parnell, who gave the first speech at the reception, followed by Mulva, Dudley and Tillerson. The topic: Southcentral LNG project.

There was no major announcement.

In a nutshell, the governor said the three companies had reported progress in discussing alignment on an instate route for the gas pipeline that would take the gas to tidewater in Southcentral Alaska where it would be liquefied for export by tanker.

He, Dudley and Tillerson also said TransCanada was involved in the discussions; and he told the three oil company CEOs that the state needs "metrics for progress."

The governor also talked about the state tax changes that would be needed.

Mulva, too, mentioned Alaska's production taxes, saying they were too high and unpredictable.

Progress has been made in the LNG discussion, he said, describing the meeting with the governor that morning as a key event for Alaska.

But, Mulva said, much more needs to be discussed.

Dudley acknowledged that there is a market for Alaska LNG in the Pacific Rim; a market, he said, that needs to be evaluated.

Tillerson, the most upbeat of the three CEOs, said ExxonMobil has done similar projects elsewhere in the world and was ready to do it in Alaska if "we can find the right alignment."

"We succeed together or we fail together," he said of the state and the industry.

He also said ExxonMobil is willing to accept the market risk, which is a risk that can't be controlled.

All three company CEOs praised Parnell and his administration at the luncheon, which was hosted by Lynden with company executive Jim Jansen the master of ceremonies.

"I have looked the governor in the eye and I know he is earnest about wanting to be a partner" with industry in Alaska, Tillerson said. "I trust him."

—KAY CASHMAN

Winegarner moves to Statoil

IN MID-DECEMBER, JIM WINEGARNER joined Statoil in Alaska as director of land, leaving his position with Brooks Range Petroleum Corp., where he has served as vice president of land since mid-2006. Winegarner has more than 30 years of experience in the oil and gas industry, mainly with ARCO and ConocoPhillips in Alaska.

Japan to get LNG from Norway via Northern Sea Route

THIS SUMMER THE WORLD'S ONLY Ice-1A winterized class LNG tanker will transport the first liquefied natural gas from northern Norway to Japan via the Northern Sea Route, per a Jan. 5 article in the Barents Observer that was based in part on a NRK report.

The gas will come from the Statoil-operated Snøhvit LNG project, the first offshore development in the Barents Sea and the first major development on the Norwegian continental shelf with no surface installations.

The project brings natural gas to land for liquefaction and export from the world's northernmost LNG facility.

According to the Barents Observer, Norway-based Knutsen OAS Shipping received permission from Russian authorities to transport LNG in the tanker Ribera del Duero Knutsen from Snøhvit to the Bering Strait, a distance of more than 3,000 nautical miles along the Russian coast of the Arctic Ocean.

That part of the journey will take about two weeks; the last leg, from the Bering Sea to Japan, will take another two weeks, which in total is about half the time it takes via the usual route from Europe to Asia through the Suez Canal.

The Northern Sea Route is a shipping lane defined by Russian legislation from the Atlantic Ocean to the Pacific Ocean, from Murmansk on the Barents Sea, along Siberia, to the Bering Strait. The entire route lies in Arctic waters and mostly ice-free for two months per year, but open to vessel traffic from June to October when there is still significant open water.

The Ribera del Duero Knutsen, the article said, can make as many as three trips in that season.

Traffic along the Northern Sea Route has increased from four vessels in 2010 to 34 in the 2011 season.

According to the Observer's report, Rosatom, the state-owned operator of Russia's nuclear icebreaker fleet, cargo transport on the Northern Sea Route was expected to reach one million tons in 2012, but Rosatom said the potential is much higher.

What hampers use of the shipping lane is the lack of suitable vessels, the article said.

According to Synnøve Seglem in Knutsen OAS Shipping, there are several other companies with ice class LNG tankers that are interested in testing out the Northern Sea Route.

According to the Voice of Russia website, developing the Northern Sea Route has become one of Russia's top priorities in the far north. In September at the International Arctic Forum, Russian Prime Minister Vladimir Putin said that Russia is developing the Northern Sea Route by expanding existing ports and building new Arctic ports; upgrading the transportation infrastructure in the region; and expanding the country's icebreaker fleet.

See related Barents Observer map and article "Record long Arctic navigation season" online at http://bit.ly/x4ydV5.

—KAY CASHMAN

Contact Kay Cashman at publisher@petroleumnews.com

continued from page 20

OIL PATCH BITS

Alaska Railroad. Mr. Silverstein will continue to assist ARRC with ongoing key projects as a Business Development Transition Specialist.

Crowley acquires 500 new 40-foot high-cube containers

COURTESY CROWLEY

Crowley Maritime Corp. said Jan. 3 that its liner services group is continuing to grow and update its equipment fleet to better serve customers with the addition of 500 new 40-foot, high-cube containers. The acquisition adds to the company's already robust equipment fleet of more than 45,000 units, as well as phases out some older containers.

The new containers, which have a capacity of 2,700 cubic feet, will be used in all liner service operations in Latin America, the Caribbean and Puerto Rico.

"Our customers value having current, reliable equipment of varying sizes when and where they need it," said John Douglass, senior vice president and general manager, Puerto Rico and Caribbean services. "This container acquisition is in keeping with our commitment to meeting and exceeding their needs."

The new containers, which contain more durable North American oak wood flooring, exceed all new and amended ISO standards for freight container door security applications. A combination of security enhancements and upgrades deters and prevents unauthorized access into containers and loaded cargo.

Editor's note: All of these news items — some in expanded form — will appear in the next Arctic Oil & Gas Directory, a full color magazine that serves as a marketing tool for Petroleum News' contracted advertisers. The next edition will be released in March.

continued from page 1

LOW-FLOW THREAT

cited as a reason to, for example, lower tax rates to encourage exploration spending to find more oil.

North Slope oil production averaged 622,355 barrels per day through the month of December. That's a far cry from the peak of 2.1 million barrels per day the 800-mile pipeline carried in 1988.

A study the line's operator, Alyeska Pipeline Service Co., issued in June said the system could continue to run "with reasonably high operational confidence" down to a throughput of about 350,000 barrels per day, provided problems such as freezing water in the oil stream were addressed.

Such freezing can occur because the oil, which enters the pipeline quite warm, is cooling on the long and increasingly slow journey to the tanker terminal at Valdez.

In contrast to the Alyeska study, the Dec. 30 ruling from state Superior Court Judge Sharon Gleason outlines compelling evidence suggesting the pipeline — with various engineering solutions — likely can operate at throughputs of 100,000 barrels per day or less.

Oil by rail

A nine-week trial in Gleason's Anchorage courtroom churned up important studies, emails and testimony indicating some costly and potentially radical ideas are under consideration to keep the pipeline running and the oil flowing.

One study completed in 2005 for BP, the largest stakeholder among the pipeline's five owner companies, contained an option to build a $3 billion, 20-inch pipeline to replace the 48-inch line from the North Slope to Fairbanks. From Fairbanks, oil would then be hauled by railroad south to tidewater for loading onto tankers.

The Alaska Railroad doesn't extend to Valdez, where tankers load. The tracks do, however, reach the seaside towns of Anchorage, Whittier and Seward.

In order to book proven reserves to the U.S. Securities and Exchange Commission, an upstream oil producer such as BP needs to perform an analysis to determine the financial feasibility of bringing the oil to market, Gleason's ruling says.

BP's 2005 study, done by JTG Technology Consortium, concluded that the low-flow limit of the existing 48-inch pipeline was 135,000 barrels per day at Pump Station 1.

The option to downsize the northern section of pipe and move oil by rail south of Fairbanks "would allow reserves to be booked down to 45,000 bbl/d, if justified by high oil prices," Gleason's ruling says.

BP used the JTG study to report its reserves to the SEC, the ruling says.

'Completely unpersuasive'

In 2010, BP retained Phil Carpenter to study whether TAPS could operate below the threshold of 135,000 barrels per day as determined in the JTG study, the Gleason ruling says.

On June 28, 2010, Carpenter gave BP an update: "I am beginning to think that it looks surprisingly good for ultra low flow below 100,000."

The final version of the Carpenter study, dated Aug. 16, 2010, concluded TAPS could effectively operate down to throughputs between 100,000 and 70,000 barrels per day by installing heaters at various intervals along the pipeline to warm the oil.

Carpenter determined further reductions in oil flow might be possible by maintaining flow velocity, with one option being "seawater commodity supplementation."

At trial, the owners argued the minimum TAPS throughput was much higher, Gleason wrote. They referenced Alyeska's low flow study issued in June and asserted the pipeline has a low flow limit of 300,000 to 350,000 barrels per day.

A shorter useful life for an asset suggests that its taxable value should be lower.

Gleason, however, termed testimony from Pat McDevitt, Alyeska's project manager on its low flow study, "completely unpersuasive." She further said the low flow study, in her view, was primarily to study the operating challenges with throughputs down to 300,000 barrels per day, and not to determine a minimum TAPS throughput capability.

Gleason said she found Dan Hisey, Alyeska's former chief operating officer, more persuasive. Hisey testified that even if heating and other low-flow measures cost the owners hundreds of millions of dollars in coming decades, such investments will be worth it to keep North Slope crude flowing and to provide transportation for future fields and production.

—WESLEY LOY

Contact Wesley Loy at wloy@petroleumnews.com

continued from page 1

PIPELINE VALUE

erable into the transportation facility" is $8.94 billion for 2007, $9.64 billion for 2008 and $9.25 billion for 2009.

Those figures are far above what the owners argued the system was worth. They asserted the assessed value of TAPS should be no greater than $1.3 billion for any of the three tax years at issue, Gleason's ruling says.

Second setback for owners

The owners went to court to challenge how state officials calculate the value of Alaska's most essential industrial asset, which has been carrying North Slope crude oil since 1977.

The ruling is the second in recent times to go against the owners. In May 2010, Gleason pegged the value of TAPS for 2006 at $9.98 billion.

The rulings constitute victories for the state and for municipal governments along the 800-mile pipeline route, as higher valuations mean greater property tax collections.

Bill Walker, an attorney for the city of Valdez, told Petroleum News with respect to the latest ruling: "We're very pleased with it."

The five companies holding ownership stakes in TAPS are BP, ExxonMobil, ConocoPhillips, Chevron and Koch Industries. BP holds the largest stake at 46.9 percent.

Steve Rinehart, BP's Anchorage spokesman, said the company was reviewing the ruling and had no further comment.

The ruling for the 2006 tax year is currently on appeal to the Alaska Supreme Court, and a similar appeal of Gleason's latest ruling is expected.

Trial covers key evidence

The non-jury trial was highly complex, covering such topics as appraisal theory and featuring numerous expert witnesses and reports.

Some sections of the ruling are blacked out, presumably to protect confidential company data.

Perhaps most significantly, the trial delved into two key areas involved in valuing the pipeline — estimates of remaining North Slope oil reserves, and the technical ability of the pipeline system to continue running as oil production continues to decline.

In these two areas, Gleason made remarkable observations as to whose production forecasts and reserves estimates she found most credible, and the throughput level at which she believes the pipeline can continue operating.

With respect to the latter, Gleason held that she believes the pipeline can continue to operate at least down to a minimum flow rate of 100,000 barrels per day.

That's a much lower rate than has generally be cited as a cutoff point for the pipeline, which recently has moved an average of just over 620,000 barrels per day.

The operator, Alyeska Pipeline Service Co., has said TAPS flow volume has been dropping at a rate of about 5.4 percent yearly.

Dueling reserves estimates

The judge's ruling devotes about 25 pages to a discussion of evidence on proven reserves, and the forecasts and estimates offered by the state, the pipeline owners and the municipalities.

In general, Gleason favored the data from the municipalities and their consultant, Dudley Platt, whom she termed "one of the preeminent production forecasters in the state." Platt for many years, until 2009, did production forecasts for the state Department of Revenue.

The judge said testimony on proven reserves from Roger Marks, a former state

see **PIPELINE VALUE** *page 23*

continued from page 1

GATEWAY TEST

ine Enbridge's technical experts and others who have presented evidence in formal hearings scheduled for September and October.

Decision by end of 2013

The NEB anticipates the complete public process will last until mid-2013, followed by the release of an environmental assessment report in fall 2013 and a final regulatory decision by the end of that year.

Even before the hearings start, that schedule is at odds with newly available public documents that show the Canadian government expected the process to be completed by mid-2012.

Natural Resources Minister Joe Oliver said in late December that while the government respects the process it is "concerned about excess delays," noting that "consultations with aboriginal and other organizations have been ongoing since 2008."

But Oliver said that although it is "very important" for Canada to diversify its energy export markets beyond the United States, he will respect the regulatory process.

Whether that means waiting until late 2013 for a decision is not clear.

Opposition to pipeline

Equally, there is little doubt that various activists, environmental groups, First Nations and local governments — drawing strength from the success of opponents in delaying TransCanada's Keystone XL pipeline — are just as determined to make their case against shipping oil sands crude by pipeline and tanker, building much of their case around the 1989 Exxon Valdez spill in Alaska and the 2010 Macondo well blowout in the Gulf of Mexico.

Linda Duncan, an Edmonton Member of Parliament from the opposition New Democratic Party, said that if the government of Prime Minister Stephen Harper has "not figured out yet that this project cannot be rubber-stamped, then they better wake up," warning Oliver against trying to fast-track the approval.

A spokeswoman for the Canadian Environmental Assessment Agency said there is "no real timeline" for hearing all of the evidence on Northern Gateway, but the joint review panel "wants to hear from everyone … who has valuable information."

Enbridge focused on credibility

Enbridge has declared its objective through the hearings is to "outline the credibility of the application" confident it has the engineering and environmental studies to prove the pipeline and tankers can be operated safely.

But it's far from clear that Enbridge has been able to win over the bulk of First Nations, especially those along the pipeline route who have been offered a 10 percent equity stake in the project.

A briefing note to federal Aboriginal Affairs Minister John Duncan said that even if Enbridge receives a "favorable" environmental ruling, unresolved Native land claims in British Columbia pose a "major obstacle," given that the pipeline crosses about 1,000 rivers and streams that are salmon spawning grounds.

A broad-based coalition of environmentalists and 130 First Nations has warned it will use legal challenges and, if necessary, civil disobedience to prevent construction of Northern Gateway.

To that threat, Oliver and others in government have confined themselves to saying that Canada will observe the rule of law.

Enbridge enters the hearing phase claiming it has reached commercial, but non-binding agreements with unnamed producers and refiners who have "fully subscribed for long-term service and capacity" on both lines — the 525,000 barrels per day oil sands crude export pipeline and the parallel 193,000 bpd condensate import line.

The company said it has enlisted 10 supporters, each of which has contributed C$10 million towards Northern Gateway's design and the regulatory process, although so far only China's Sinopec has publicly disclosed it is one of the parties.

However, FirstEnergy Capital analyst Steven Paget said the deals give some assurance to the joint review panel that the project is commercially viable and supported.

The terms of reference require the joint review panel to weigh the public interest on behalf of "all Canadians" balancing "economic, environmental and social considerations," embracing more than Canada's traditional regulatory focus on just an environmental assessment.

Jolan Bailey, speaking for the environmental group ForestEthics, said the project has clearly "struck a public nerve. This is really a wall of public opposition."

The New York-based Natural Resources Defense Council, a leading opponent of Keystone XL, has joined the campaign by mobilizing its members to send 60,000 emails to British Columbia Premier Christy Clark.

Enbridge Chief Executive Officer Pat Daniel said that if U.S. charitable foundations try to derail Northern Gateway they may discover "most people think it's more important to have security of oil supply and alternative markets."

He said the joint review panel faces two key decisions: Is Northern Gateway in Canada's national best interest and can it be built in an environmentally sound and effective way?

The challenge for the joint review panel will be to keep its hearings within those confines and for the Canadian government to deal with the potentially explosive issues that are unrelated to the regulatory terms of reference. ●

Contact Gary Park through publisher@petroleumnews.com

continued from page 22

PIPELINE VALUE

economist working for the owners, was "not persuasive."

She also called the Department of Revenue's production forecasts and reserves estimates "unreliable" for her purposes in deciding the case.

Consultant Frank Molli succeeded Platt as a production forecaster for the Department of Revenue.

But his "well-by-well analysis and methodology failed to capture significant barrels of oil that should be properly included in forecasts for each of the assessment years," Gleason wrote. "Mr. Molli also did not save all of the data necessary to permit a complete review of his work product."

Molli also didn't prepare a forecast for each of the tax years at issue. Rather, at trial he presented his forecast from the department's Fall 2010 Revenue Sources Book, which the state's petroleum property assessor, Jim Greeley, then "adjusted backward" for each of the three tax years, Gleason's ruling says.

Among her other criticisms, Gleason said Molli did not attempt to incorporate BP's internal forecasts into his analysis or use them to validate his own results. His failure to do so "had a substantial negative impact" on the weight she gave to his reserves analysis.

Pipeline life to 2068

Gleason concluded the municipalities offered the "best available estimate" of total proven reserves. Using a minimum throughput limit of 100,000 barrels per day, and not counting the undeveloped and disputed Point Thomson unit, Gleason pegged proven reserves for the most recent tax year of 2009 at 7.077 billion barrels, with pipeline life extending to 2068.

The ruling says the taxable TAPS property includes "only the tangible real and personal property" from Pump Station 1 through the Valdez Marine Terminal and does not include intangible property, tankers, crude oil or "any property that is upstream of Pump Station 1."

The ruling notes that the final cost of TAPS, when completed in 1977, was about $8 billion.

Its design capacity was 1.42 million barrels per day, but with the use of chemical drag reduction agents, it was able to move 2.1 million barrels per day at the peak in 1988. ●

Contact Wesley Loy at wloy@petroleumnews.com

continued from page 1

HILCORP DEAL

resource plays," the company said.

In October Hilcorp named John Barnes as senior vice president for its Hilcorp Alaska LLC subsidiary. Hilcorp said Barnes, formerly with Marathon in Alaska and most recently senior vice president of operations and maintenance services for CH2MHill, brings both producer and contractor experience to the position.

Plans for Cook Inlet

Hilcorp said in its Jan. 4 statement that its "focus is to continue to develop and produce Cook Inlet's resources in a safe and environmentally sound manner that will provide benefits for the company, its employees and the State of Alaska."

Assets which Hilcorp acquired include Union Oil contracts and interests in the Swanson River, Granite Point, Middle Ground Shoals, Trading Bay and MacArthur River fields; interests in 10 offshore platforms; interests in onshore gas fields including the Ninilchik Unit and the Beluga River Unit; and two gas storage facilities.

When the sale was announced in July production from the assets was listed as some 3,900 barrels of oil and 85 million cubic feet of natural gas per day.

As of November production data from the Alaska Oil and Gas Conservation Commission, Granite Point, McArthur River and Middle Ground Shoals — among the interests acquired by Hilcorp Alaska — are the only fields in Cook Inlet with average production of more than 1,000 barrels per day.

The sale also includes interests in the Cook Inlet Pipe Line Co. and Kenai Kachemak Pipeline LLC.

Chevron retains its non-operated joint venture interests on the North Slope and its 1.36 percent interest in the trans-Alaska oil pipeline.

State transfers required

State approvals were required, including regulatory approvals for pipeline transfers.

The Regulatory Commission of Alaska approved transfers of interests in Cook Inlet Pipe Line, Cook Inlet Gas Gathering Systems and Kenai Kachemak Pipeline in December, subject to approval of transfers by the Department of Natural Resources of interests in right-of-way leases.

DNR Deputy Commissioner Joe Balash said Dec. 13 that the department had work under way in multiple divisions on various lease assignments related to the sale, including oil and gas leases, easements and other surface authorizations, as well as the Kenai Kachemak Pipeline lease.

He said the department knew the companies wanted to close by year end, and was doing everything it could to facilitate that.

Balash told Petroleum News in a Dec. 29 email that the department had completed assignments that morning and understood the Union-Hilcorp deal would close the next day.

"We have a new operator in Cook Inlet that looks to be ready to invest in assets that still have plenty of juice in them," he said.

In its Jan. 4 statement Hilcorp acknowledged the efforts of Chevron employees and state and federal agencies in the regulatory approval process for the sale.

Investment planned

While Hilcorp did not discuss specific plans in its Jan. 4 statement, it made some general information available earlier in the year in regulatory filings.

In a narrative statement about Hilcorp's proposed acquisition filed with the Regulatory Commission of Alaska, or RCA, in August as part of the application for transfer of pipeline interests, Hilcorp said it "has identified the Cook Inlet basin as a region holding significant potential for continued oil and gas exploration and development opportunities, and, consistent with its overall corporate mission, upon completion of the acquisition, Hilcorp intends to pursue a maintenance and development program at existing fields, as we as a comprehensive exploration program."

Hilcorp told RCA it "is poised to begin making substantial investments in its newly acquired Cook Inlet assets over the next several years." The company said the investment "is anticipated to lead to increased production from the underlying oil and gas assets, which should increase the useful life of these pipeline assets," while benefitting "the broader economy in Southcentral Alaska as well as creating jobs and stimulating economic activity."

Reputation as a good employer

On its website, Hilcorp describes the company's beginnings "as the proverbial 'three guys and a telephone' trying to make a living in the oil and gas business."

Since then Hilcorp has grown to become one of the largest privately held E&P companies in the United States.

In a CEO message on Hilcorp's website, Jeff Hildebrand, the company's founder, president and CEO, cites "world-class employees, legacy assets and a strong balance sheet" as the reasons for the company's success.

"We focus on what we do well," Hildebrand said, listing the company's core competencies as engineering and geological expertise and operational excellence.

The company's mission, he said, is "To efficiently develop energy that would otherwise be lost while providing an enjoyable and challenging work environment where long-term personal wealth can be created." ●

Contact Kristen Nelson at knelson@petroleumnews.com

continued from page 1

GLACIER RIG

early 2001 had succeeded in drilling to a depth of 12,000 feet; it also drilled a 2,600-foot horizontal at a depth of nearly 9,000 feet, Barnes said.

Marathon has made extensive use of the rig for the drilling of development wells in the company's gas fields in the Cook Inlet basin. The company has also used the rig for exploration drilling on the Kenai Peninsula, at West Fork in 2005 and at Sunrise in 2010, for example.

But the company's use of the rig has declined in recent years — although in the mid-2000s Marathon was drilling about 10 wells per year, that number dropped to nine wells in 2008, six wells in 2009 and three wells in 2010.

In 2011 Marathon contracted the rig out for gas exploration drilling in the Cook Inlet basin by NordAq Energy Inc. and Buccaneer Energy Ltd.

—ALAN BAILEY

Contact Alan Bailey at abailey@petroleumnews.com