Inside: Petroleum News Bakken

A Third Phase
Brooks Range Petroleum aiming for the era of the small independent

By ERIC LUDJI
Petroleum News

With its announcement of a 40 million barrel discovery at its Mustang prospect, Brooks Range Petroleum Corp. is entering development mode after 13 years of exploration. It could also be entering the phase of the history of North Slope development.

After decades where only a few majors could afford to operate on the North Slope, the past decade saw the arrival of larger independents and new overseas entrants. With a commercial operation at Mustang, Brooks Range Petroleum could help usher in an era where many smaller independent producers could set up shop on the North Slope, too. It would follow in the footsteps of Savant Alaska, the company now in charge of the Badami unit on the eastern North Slope, and Armstrong Oil & Gas, the pioneering independent that brought lots of new overseas players to Alaska and is now working alongside fellow independent GMT Exploration Co and Spanish major Repsol E&P USA to explore a large swath of acreage extending north of the Mackenzie Delta.

In the coming year, Brooks Range Petroleum could theoretically conduct as much exploration and development work as is has in its entire history until now.

Marathon to exit Alaska
Selling its Cook Inlet assets to Hilcorp to focus on oil resources elsewhere

By ALAN BAILEY
Petroleum News

A nother major change in the landscape of the Alaska oil and gas industry emerged on April 9 when Marathon Oil Corp. announced that it had agreed on the sale of all of its Alaska assets to Hilcorp Alaska, the Alaska division of Houston-based Hilcorp Energy Co. Marathon is a major natural gas producer in Alaska’s Cook Inlet basin and has been operating in the state since the 1950s.

“We’ve been operating here for almost 58 years and over that time we have certainly valued all the relationships that we have throughout the state,” Wade Hutchings, Marathon’s Alaska asset team manager, told Petroleum News on the day that the sale was announced.

The Marathon sale comes on the heels of Hilcorp’s purchase of all of Chevron’s Cook Inlet oil and gas assets in 2011.

Corporate strategy
The sale reflects a Marathon corporate strategy

Mackenzie project falters
Partners scale back budgets, reduce staff, close offices; Conoco records impairment

By GARY PARK
Petroleum News

Dead man walking, a self-induced coma, or a holl in proceedings — call it what you want, but the latest lurch in the drawn-out history of the Mackenzie Gas Project does not bode well for the plan to commercialize Canada’s stranded Arctic natural gas.

Amid a flurry of mixed messages on April 8 from partners in the MGP consortium, the emerging consensus is that budgets are being slashed and some staff are being laid off in response to the erosion of project economics caused by a dismal outlook for natural gas prices.

ConocoPhillips set the ball rolling by announcing it was recording a first-quarter non-cash impairment for the carrying value of its undeveloped stakeholdings on the Mackenzie Delta and capitalized project development costs of about US$525 million after-tax.

Lead partner Imperial Oil said its ExxonMobil
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Petroleum News
North America’s source for oil and gas news

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pat.hanley@umalaska.com  |  www.umalaska.com
### Alaska Rig Status

#### North Slope - Onshore

<table>
<thead>
<tr>
<th>Rig Owner/Rig Type</th>
<th>Rig No.</th>
<th>Rig Location/Activity</th>
<th>Operator or Status</th>
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<tbody>
<tr>
<td>Doyon Drilling</td>
<td>Dreco 1200 14 (SCR/TD)</td>
<td>Prudhoe Bay Z-50</td>
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<tr>
<td></td>
<td>Dreco 1000 UE 16 (SCR/TD)</td>
<td>Prudhoe Bay PrM33 12-13</td>
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<td>Dreco 2000 UEBD 19 (SCR/TD)</td>
<td>Alpine CED-119</td>
<td>ConocoPhillips</td>
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<td>AC Mobile</td>
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<td>Prudhoe Bay P3-39</td>
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<tr>
<td>OIME 2000</td>
<td>141 (SCR/TD)</td>
<td>Alpine CDA-27</td>
<td>ConocoPhillips</td>
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<tr>
<td>TSM 7000</td>
<td>Arctic Fox #1</td>
<td>Alpine Qugruk #4</td>
<td>Repsol</td>
</tr>
<tr>
<td>Kasigak</td>
<td>5</td>
<td>Demobilizing to Nari Beach</td>
<td>North Slope Borough</td>
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#### Nubors Alaska Drilling

<table>
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<tbody>
<tr>
<td>Trans-ocean rig</td>
<td>CDR-1 (CT)</td>
<td>Stacked, Prudhoe Bay</td>
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<tr>
<td>AC Coiled Tubing</td>
<td>CDR-2</td>
<td>Kuparuk 3K-10A</td>
<td>ConocoPhillips</td>
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<tr>
<td>Dreco 1000 UE</td>
<td>2-ES</td>
<td>Prudhoe Bay Stacked out</td>
<td>Available</td>
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<tr>
<td>Oilwell 700 E</td>
<td>4-ES (SCR)</td>
<td>Prudhoe Bay X-22A</td>
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#### Nordic Calista Services

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<tr>
<td>Superior 700 UE</td>
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<td>Prudhoe Bay Drill Site J-16B</td>
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<tr>
<td>Superior 700 UE</td>
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<tr>
<td>McDerrio</td>
<td>3 (SCR/CTD)</td>
<td>Kuparuk Well 1D-112</td>
<td>ConocoPhillips</td>
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#### Nabors Alaska Drilling

<table>
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<tbody>
<tr>
<td>OIME 1000 19-E (SCR)</td>
<td></td>
<td>Oooguruk ODSN-25</td>
<td>Pioneer Natural Resources</td>
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<tr>
<td>OIME 2000 245-E</td>
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<td>Oliktok Point OP21-WW01</td>
<td>ENI</td>
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<td>Oilwell 2000 33-E</td>
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<td>Available</td>
</tr>
<tr>
<td>Emsco Electro-hoist-2</td>
<td>18-E (SCR)</td>
<td>Stacked, Deadhorse</td>
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#### Nabors Alaska Drilling

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<th>Operator or Status</th>
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</thead>
<tbody>
<tr>
<td>Top drive, supersized</td>
<td>Endicott SDI for Liberty oil field</td>
<td>BP</td>
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#### Aurora Well Service

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</thead>
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<tr>
<td>AWS 1</td>
<td></td>
<td>Doing work overs at Swanson River for Hilcorp</td>
<td>Aurora Gas</td>
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#### Cook Inlet Basin - Onshore

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<th>Rig Location/Activity</th>
<th>Operator or Status</th>
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</thead>
<tbody>
<tr>
<td>Marathon Oil Co. (Inlet Drilling Alaska labor contracting)</td>
<td>Taylor 641</td>
<td>Undergoing winterization at W. McArthur River Unit</td>
<td>Cook Inlet Energy</td>
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</tbody>
</table>

#### Mackenzie Rig Status

<table>
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<tr>
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<th>Rig No.</th>
<th>Rig Location/Activity</th>
<th>Operator or Status</th>
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</thead>
<tbody>
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<td>SDC Drilling Inc.</td>
<td>SDC</td>
<td>Set down at Roland Bay</td>
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### The Alaska - Mackenzie Rig Report

The Alaska - Mackenzie Rig Report as of April 12, 2012. Active drilling companies only listed.

This rig report was prepared by Marti Reeve.

### Baker Hughes North America rotary rig counts*

<table>
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<tr>
<th>Category</th>
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<th>Year Ago</th>
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<td>191</td>
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<tr>
<td>Gulf</td>
<td>44</td>
<td>46</td>
<td>28</td>
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### Highest/Lowest

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<tbody>
<tr>
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<td>4530</td>
<td>December 1981</td>
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<tr>
<td>Canada</td>
<td>488</td>
<td>April 1999</td>
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<tr>
<td>Gulf</td>
<td>568</td>
<td>January 2000</td>
</tr>
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<td>Canada/Lowest</td>
<td>29</td>
<td>April 1992</td>
</tr>
</tbody>
</table>

*Issued by Baker Hughes since 1944.
Reps. Joule, Herron talk arctic policy

By STEFAN MILKOWSKI
For Petroleum News

How can Alaska ensure that offshore drilling and marine traffic don’t harm arctic communities? That subsistence resources are safeguarded and the impacts of climate change understood? Reps. Joule and Herron have one idea: pull together a wide range of experts over the next three years to develop a comprehensive, Alaska-centric arctic policy.

Both lawmakers served on the Alaska Northern Waters Task Force, a legislatively created group that held hearings around the state and issued its final report in January.

Joule, who chaired the group, says continuing that work is critical. Through the House Finance Committee, he is sponsoring a resolution to establish a 17-member Alaska Arctic Policy Commission (HCR 22). The resolution passed the House in March and has the support of Gov. Sean Parnell.

Reps. Joule and Herron spoke with the two lawmakers on April 9 about arctic planning, offshore drilling, and coastal management.

Petroleum News: One recommendation of the Northern Waters Task Force is to create an Alaska Arctic Policy Commission. Why do we need a group like that?

Joule: The big thing obviously is offshore development. That’s now, that’s present.

I guess I’ll even back up a little before that. Probably the biggest thing that’s causing all this consideration is the pace of climate change, with the acceleration of the melting of the ice cap. It used to be something we talked about that was 20, 30, or 40 years out. Now this summer we’re looking at drilling and increased marine transportation. Those are the two immediate things.

People who live in the areas close by are somewhat concerned about food security, with subsistence resources.

Petroleum News: What’s going on the Arctic now that wasn’t going on a few years ago?

Joule: Well, do you want the feds to do it all? We pride ourselves on trying to control our own destiny. In the absence of planning, we’re reacting. And we don’t often react very well.

This gives us an opportunity to take a look forward with stakeholders from around the state and determine how we’re going to move forward with all this activity going on in the foreseeable future.

Herron: When the Northern Waters Task Force had its first meeting (in October 2010) in Anchorage, what surprised everyone was how many people outside the state of Alaska knew what they were doing. Sure, someone (from state government) knew what someone was doing in a related agency. But it was report after report of mostly other people, federal government and otherwise, doing research on Alaska.

That was the first realization that we’re just going along here without a comprehensive Alaska arctic policy.

There are so many things that Alaskans have to decide. We could let others decide, and be unsatisfied at the end that they didn’t think about this, didn’t think about that.

The proposed Alaska Arctic Policy Commission gives us three years with a good group of people, whoever they might be, to decide how we relate to our own national government and other arctic nations. At the same time, how do we provide for the people of Alaska and make the economy not only sustainable but also thriving?

Joule: Alaska is what makes the United States part of the Arctic Council. Other arctic nations have their policies in place. The United States started out with a federal policy, but no plan of implementation. This allows Alaska an opportunity to develop an arctic policy during a time when Canada and the United States will chair the Arctic Council, Canada taking the chair in 2013 and the United States taking it in 2015.

Petroleum News: Are there specific things that the federal policy that don’t work for Alaska?

Joule: Well, everybody has an opinion on that national policy, which was implemented days before President Bush left office and essentially endorsed by President Obama, much to the concern and consternation of some.

Herron: We use the analogy that the Northern Waters Task Force was a feasibility study. This is going to be action, with 17 people making recommendations on policy.

We found so much that needs to be addressed. Hopefully the commission can create a list that will say, This is the stuff that needs to be looked at, and another list that says, This is the stuff that’s coming.

Joule: If we don’t have a strategy to implement, it’s going to be, I don’t know if chaos is the right word — highly political maybe. But it’s going to be confusion.

We need to have some structure to bring people together so we can figure out what our policy is going to be.

Petroleum News: So the commission would develop policy recommendations and then do what?

Joule: Correct. Herron: A preliminary report is due to the Legislature January 30, 2014, with the final report and legislative proposals one year later.

We’re asking the governor to put somebody from the executive branch on the commission. There are many Alaskans serving Alaska that are good at... see HOUSE REP Q&A page 15

By REGGIE JOULE
For Petroleum News

石油新闻：让市场决定这项大而复杂的计划

石油新闻：推动阿拉斯加的北极政策，强调需要强大的阿拉斯加声音

石油开发、海上钻井、海岸管理。

阿拉斯加北极政策

在2013年和美国担任主席之前，阿拉斯加可能拥有一个机会来发展一项北极政策。在加拿大和美国之间，谁将领导北极理事会，加拿大将在2013年担任主席，美国将在2015年担任主席。

石油新闻：阿拉斯加有什么政策？

石油新闻：在3月的社论中给出了具体的政策建议和联系方式。

石油新闻：在3月30日，立法者将收到一份初步报告，到2014年1月30日，将提交一份最终报告和立法提案。一年后。

石油新闻：问后者根据。”
Alberta dynasty under threat

Governing Progressive Conservatives led by Alison Redford faced with defeat by right-wing Wildrose Party led by Danielle Smith

By GARY PARK
For Petroleum News

Panic is sweeping through the inner circles of Alberta’s governing Progressive Conservative party, which some critics are suggesting has forgotten how to campaign after 41 years in power.

One of the true democratic dynasties anywhere is faced with defeat on April 23 as the polls start shifting away from rookie Premier Alison Redford to Danielle Smith, leader of the upstart Wildrose Party.

Not quite what was expected of Redford as she entered the four-week campaign with a healthy backing from voters and the respect of Canadians — even some Americans — outside Alberta.

One U.S. delegate to FirstEnergy Capital’s annual conference in Calgary in early March was so impressed by Redford’s energy views he invited her to become Mitt Romney’s running mate in the expected showdown with President Barack Obama.

Tongue in cheek, of course, but evidence of Redford’s command of policy as she outlined her vision of Alberta’s role in supplying crude to the world market and her plans to support the focus on industry, but she appears to be rapidly losing ground to the Wildrose.

Despite the early March was so impressed by Redford’s command of policy as she outlined her vision of Alberta’s role in supplying crude to the world market and her plans to support the focus on industry, but she appears to be rapidly losing ground to the Wildrose.

Wildrose leads polls

One of the latest polls shows the right-wing Wildrose at 43 percent of decided voters, with the Conservatives at 30 percent, the left-wing New Democrats at 12 percent, the Liberals at 11 percent and 4 percent among fringe parties. Of those sampled, 19 percent were undecided.

ThinkHQ pollster Marc Henry said Redford’s Conservatives have dug “an awfully big hole for themselves.”

The apparent appetite for change is being fed by Smith’s promise of an energy dividend of C$300 for every Albertan as early as 2015 once the province has created a fund of C$750 million.

Redford challenged the pledge, arguing the plan did not fit with Wildrose’s promise to build a C$200 billion Heritage Fund from surplus energy revenues and to hold the line on taxes, accusing Smith of “robbing the next generation to buy today’s vote.”

Although Wildrose, an alliance of libertarians and fiscal conservatives, has only four of eight members in the Alberta legislature, Smith has attacked Redford in what should be the premier’s energy stronghold.

Smith said she has “no idea what (Redford’s) national energy policy looks like. I think she’s engaging in a lot of babble and double talk.”

“Alberta cannot be engaging in some simplistic, and McGuinty softened his views, but the damage had been done to Redford’s proposed national energy policy. In a volatile voting environment, which initially had Redford cruising to an emphatic victory and now, in the eyes of some, has Smith in an unsailable polling lead, the next two weeks shape up as an unprecedented fight in Alberta, which has had only two governing parties in the last 77 years.”

Contact Gary Park through publisher@petroleumnews.com

To advertise in Petroleum News, please contact Susan Crane at 905-770-5592, or Bonnie Henkner at 412-483-9705.
The State of Alaska is expected to collect approximately $9.9 billion in unrestricted revenue in fiscal year 2012, which ends in June, and $8.4 billion in FY 2013, the Department of Revenue said April 6 in its spring revenue forecast.

Revenue Commissioner Bryan Butcher said in a statement that while higher-than-expected crude oil prices provided the strong revenue outlook, “the long-term health of the state’s finances and Alaska’s economy depends on stemming the continuing decline in North Slope oil production.”

The department said revenue from oil and gas production is expected to provide more than 90 percent of the state’s unrestricted revenue through FY 2021.

The fall revenue forecast, released in December, was for $8.9 billion in unrestricted revenue this fiscal year and $8.2 billion in FY 2013.

The spring forecast for Alaska North Slope crude oil prices is $114.59 per barrel for this fiscal year, compared to $109.33 in the fall forecast, and $110.44 per barrel for FY 2013, compared to $109.47 in the fall forecast.

The price forecast

The price forecast for the ANS crude oil price on the West Texas Intermediate is forecast as of March 7 for a WTI annual average of $101.66.

Revenue Commissioner Bryan Butcher said in a statement and average Bloomberg analysts’ forecasts as of March 7 for a WTI annual average of $101.66.

ANS is forecast to trade at $17.23 above WTI for this fiscal year and $8.78 above WTI for FY 2013; adding on that differential produces the FY 2012 forecast of $114.59 and the FY 2013 forecast of $110.44.

The state’s unrestricted oil revenue for this year is forecast at $9.163 billion, compared to an actual of $7.049 billion in FY 2011. The forecast for FY 2013 is $7.7 billion. Unrestricted oil revenues forecast for this fiscal year include property tax ($91.7 million), corporate petroleum income tax ($552.8 million), production tax ($6.386 billion) and royalties, including bonuses, rents and interests ($2.133 billion).

Restricted oil revenues add almost another billion dollars and include royalties going to the permanent fund ($947 million), tax settlements to the constitutional budget reserve fund ($27.6 million) and royalties, rents and bonuses from the National Petroleum Reserve–Alaska of $5 million, for a total of $1008 million, and a total for unrestricted and restricted oil revenue of $10.143 billion. All other revenue, unrestricted and restricted, is forecast at $1.02 billion for this fiscal year.

The state also expects $3.127 billion in federal revenue (all restricted) and $154.4 million in unrestricted and $3.316 billion in restricted income revenue.

Total unrestricted revenue is projected at $9.870 billion and restricted revenue at $7.887 billion, a total of $17.757 billion.

Production

Alaska North Slope production is forecast at 580,000 barrels per day for this fiscal year, compared to actual production of 599,000 bpd in FY 2011. Continuing production decline is forecast, with production falling below half a million barrels a day in FY 2020 at 493,000 bpd.

Unrestricted oil revenues forecast for this fiscal year include property tax ($91.7 million), corporate petroleum income tax ($552.8 million), production tax ($6.386 billion) and royalties, including bonuses, rents and interests ($2.133 billion).

Revenue said its FY 2012 production forecast represents a 3 percent decline from FY 2011, with another 3 percent decline projected for FY 2013. The decline from currently producing sectors is projected at 7 percent this fiscal year and 12 percent in FY 2013.

The department is forecasting a North Slope production decline at an annual rate of 3 percent this decade, with currently producing sectors forecast to decline at an annual average of 8 percent.

It is forecasting North Slope oil field investment to increase slightly this fiscal year, at $5.2 billion, compared to $4.931 billion in FY 2011. The FY 2011 total represents $2.614 billion in operating expenditures and $2.317 billion in capital expenditures.

The department said it expects capital investment to remain flat in FY 2012 relative to FY 2011. “This reflects a continuing lack of capital investment in the state,” Butcher said.

Revenue forecasts $2.62 billion in opex in FY 2013 and $3.1 billion in capex, a total of $5.718 billion.

Lease expenditures per barrel of oil produced were $12 a barrel in FY 2011 for opex and $10.60 for capex, the per-barrel forecast for this fiscal year is $13.50 per barrel opex and $11 per barrel capex.

For FY 2013, opex is forecast to be $12.70 per barrel and capex $15.10 per barrel.
Industry: Senate tax doesn’t move needle

North Slope producers tell committee proposal won’t make state projects competitive for investment capital in current price range

By KRISTEN NELSON

The Senate Finance Committee got some praise from industry for the work it has put into crafting changes to Alaska’s oil and gas production tax, but oil and gas company executives told the committee April 6 that tax changes in the bill would not make North Slope projects competitive for investors.

The Senate Resources Committee moved the Senate’s version of oil tax change, Senate Bill 192, in March. The bill has been in Senate Finance since, where it has undergone substantial changes, but the focus remains the same: finding ways to incentivize new production, maintaining taxes on existing production at about the same level at $100 oil and reducing the impact of progressivity at higher oil prices.

Small producer perspective

Todd Abbott, president of Pioneer Natural Resources Alaska, which became the state’s first independent North Slope producer in 2008 when Ooguruk came online, told the committee that since the company came to Alaska in 2002 the state has “lost its competitive position compared to the lower-risk high-margin projects that we see across the U.S. that are not bound by many of the geographical, logistical, climatic and financial challenges that are inherently present in Alaska.”

Abbott said the Senate Finance co-Chair Bert Stedman, R-Sitka, what would move the needle and make Alaska competitive, Abbott said he used to run Pioneer’s corporate finance division where he was responsible for looking at the company’s portfolio and making capital allocation recommendations to executive management.

Compared to other properties where Pioneer is spending large amounts of capital, Alaska starts off with disadvantages. “It’s dirtier up here,” the logistics are extraordinarily challenging, and you’ve got to find a larger accumulation and a more productive well than you do in Texas to be economic, even before taxes. And so then when you throw a more onerous tax system on it, it pushes it out further.”

Abbott said he recognized the committee was looking for specific numbers, and said “that’s hard to do because I would tell you that given the risks and given kind of the inherent disadvantages up here in Alaska, you need a tax system that’s even more favorable to industry than what you see down south.”

Non-operator perspective

Dale Pittman, who manages ExxonMobil’s production business in Alaska, told the committee he believes the hard work they’ve put in and said from listening to the discussions he thinks legislators are beginning to recognize that the state’s current production tax system isn’t designed to incentivize “significant increases in investment” needed to resolve the production decline issue.

But he said ExxonMobil believes the bill will “fall short of really creating the kind of development and investment, significant changes in development and investment, that’s going to be needed by the state.” He said while the Senate bill “represents a significant shift from ACES particularly at the extremely high commodity levels ... it remains far short of what we believe to be required to make the current annual investment.”

And the fact that the Senate bill tracks ACES on government take levels up through $110 or $125 a barrel commodity prices, “again causes me some concern. As you look forward, it really hasn’t attracted the kind of investment we’d like to see in the state, so I’m not sure how that’s going to change going forward.”

Pitman said he recognized the issue led legislators to have, or at least try to have, AB protecting the state’s revenues, but said it’s critical “to strike the right balance between that state take and the ability to attract that investment” needed to ensure the state’s revenues for the long term.

And while new oil is important, he said that in the next five to 10 years the potential for additional production lies in existing fields.

Stedman asked about the leveling off of production at 600,000 bpd, and Pitman said with Alaska’s “very significant” resource potential, he would be amazed if production couldn’t be leveled off in a few years, “with the right fiscal policies, the right investors, the right attitudes and the right cooperation between the producers and the state.”

Oil price issue

BP and ConocoPhillips, operators of Kuparuk and Alpine, the state’s largest fields and the ones that made the committee bill would not encourage investment.

Damin Bilbao, head of finance, development and resources for BP Exploration (Alaska), said the development of the bill the company had seen was a tax increase that would cause the company to re-evaluate existing activity; that it was not a meaningful flow and wanted to make sure more investment; was likely to create misalignment between producers which would slow or stop activity; and in the long term created more disincentive than ACES.

SB 192 is aimed at reducing progressivity at price levels above $100, but Bilbao said that BP looks at a lower price range in its planning and said that lower price range the bill is a tax increase.

He said he couldn’t be specific about the range of prices, but a slide he presented appeared to indicate that price range was between $70 and $120 a barrel, and he told the committee he didn’t disagree with the $70 to $90 price range the Department of Revenue had discussed.

Tom Williams, senior tax and royalty counsel for BP, said “if you’re looking at $65 to $125 oil in your planning scenario then you’re seeing this as a tax increase.” He noted that while $125 is only a little above where oil price is currently, futures posted for West Texas Intermediate in 2013 are at $85.

While oil spikes may occur, Williams said that’s generally over a three or four work period. “but basically, since the time of Abraham Lincoln, we are at the highest price levels that it’s been in real terms.”

Misalignment a concern

Because the bill incentivizes additional production based on a decline curve by operator, Bilbao said it was likely that it could cause misalignment between producers, because each producer will have a different target rate for oil production at a reduced tax for additional production.

The companies don’t always agree when project decisions are being made, Bilbao said, “and with this type of misalignment it adds an additional layer of complexity,” particularly in short-term projects, where producers are targeting different project which could provide tax relief.

He said SB 192 also “effectively creates an incentive around short-term production increase” because it encourages finding a way to get more production.

With the resources available, “if I have to decide between investing, putting those resources, those people, that workforce on projects that give me that rate that I want to go forward with, one year or two years, I have now an incentive to shift those resources to the short-term.”

Using the structure under SB 192, Bilbao said BP recommended dropping the base rate from 25 percent to 22.5 percent, reducing the minimum tax to 5 percent with a base rate in place until $800 (the bill proposed $690) and progressively kicking in at 0.2 percent, maxing at 10 percent at $130 per barrel and then declining to 0.1 percent and maxing out at 15 percent at $180 a barrel oil.

Asked about the dollar volumes of these changes, Bilbao said it would approximate House Bill 110. He said that as BP has told legislators, “whether it’s HB 110 or a different vehicle, it’s that level of impact that’s going to shift the needle on additional investment,” and is what would be required to incentivize needed capital.

Base rate still too high

ConocoPhillips representatives also told the committee that the base rate was still too high under SB 192, and said new oil incentives were insufficient to offset that high base tax rate. The company said the floor represented a tax increase at low prices, and while it said indexing in the bill was a positive step, it said the bill wouldn’t improve the investment climate.

Scott Jepsen, vice president of external affairs for ConocoPhillips Alaska, said the company sees “no real change from ACES” in the version of SB 192 the committee had on the table April 6.

He said when ConocoPhillips looks at the proposed bill, “we really don’t believe that it’s sufficient to move the needle if you will to create the kind of capital investment climate that we need to see on the North Slope to significantly attract more capital for North Slope projects.”

ConocoPhillips is the operator at Kuparuk, and Stedman asked what kind of incremental investment it would take to stop decline and increase production at Kuparuk.

Jepsen said he believes “it’s technologically and economically not viable to get the decline at Kuparuk,” but said he didn’t have a figure for the amount of capital that would take. He said that under ACES, the company has “devoted resources to developing proj ect...
Canada’s tiny NPA has big gas line role

Agency official visits Alaska, lays out upcoming work; path is unclear as TransCanada and North Slope gas owners change course

By WESLEY LOY

A North Slope natural gas pipeline has been a longtime focus not only for Alaska, but for neighboring Canada. And if plans for a gas line down the Alaska Highway to Alberta ever take off, we’ll be hearing a lot more about an obscure Canadian office called the Northern Pipeline Agency.

The NPA would oversee the planning and building of the Canadian segment of the gas line. Although chances for construction would appear unlikely at the moment, due to low gas prices and resurgent interest in an all-Alaska line, the NPA has considerable work upcoming.

The agency’s assistant commissioner, Chrystia Chudczak, was in Alaska recently to talk with legislators, industry players and others about the NPA’s outlook. She assured all that Canada stands ready for a pipeline.

Some of her words at a March 29 breakfast meeting of the Resource Development Council for Alaska certainly rang familiar. “So let’s deal with the elephant in the room,” Chudczak began. “This project will only go ahead if it’s commercially viable, if the markets want it, and if producers are able to secure customers.”

Agency’s deep roots

Commercial viability is a detail that sometimes seems forgotten amid the political clutter over how to achieve a gas line, one of the state’s fondest but most frustrating economic development goals. The extreme risk and cost of the 1,700-mile line, now estimated at $32 billion to $41 billion, has thus far precluded construction.

Chudczak became the NPA’s assistant commissioner in September 2011, having previously served in quite a variety of government posts. Her agency would play a commanding role on an Alaska gas line into Canada. And it’s a role that’s been long-anticipated. Canada’s Northern Pipeline Act of 1978 created the NPA.

The agency, based in the Canadian capital of Ottawa, has responsibility for facilitating efficient planning and construction of the pipeline, for considering regional and aboriginal interests, and for issuing permits.

In effect, the NPA is a fusion of two U.S. agencies—the Office of the Federal Coordinator for Alaska Natural Gas Transportation Projects, which is a facilitator but doesn’t issue permits, and the Federal Energy Regulatory Commission. Although its responsibilities are broad, the NPA is narrowly focused on a single project—TransCanada’s proposed Alaska Highway gas line. Under the 1978 act, Calgary-based TransCanada and its Foothills subsidiary hold certificates for construction of the Canadian portion of the line.

Competing firms are free to pursue an Alaska gas line through Canada, but the NPA wouldn’t oversee such a project. Rather, that duty would fall to the National Energy Board, Canada’s FERC equivalent. Likewise, the NPA has no involvement with Canada’s proposed Mackenzie Valley gas pipeline.

A major announcement

Since 2008, when the state awarded a special license to the company in exchange for certain commitments, TransCanada has been actively pursuing its gas line project. ExxonMobil, the top North Slope gas owner, is partnering with TransCanada.

The partnership views the old Foothills certificates as “a key advantage” for its project. Thus far, however, TransCanada has failed to attract sufficient gas shippers for the line. And other factors have come into play recently that seem to lessen the chances for an Alaska Highway line.

First, the North American price of natural gas has sunk to very low levels. Second, major North Slope gas owners BP, ConocoPhillips and ExxonMobil, along with TransCanada, on March 30 jointly announced they’ll look at possibly exporting liquefied natural gas, or LNG, from an Alaska port as an alternative to building a gas line through Canada.

This latest development is significant for the NPA. TransCanada, under its state license, faces an October deadline to apply for a FERC certificate to build and operate the gas line. TransCanada has indicated it would like to make concurrent filings with the NPA.

But this schedule could change with the new focus on a possible LNG project. A TransCanada spokesman did not return a phone call seeking comment.

Upcoming NPA activity

Regardless, Chudczak indicated her agency has a number of important chores ahead. One is dealing with the Foothills construction easement through Yukon. The easement is due to expire on Sept. 20, and TransCanada is expected to pursue an extension.

Chudczak also said her agency aims to form advisory councils to sound out First Nations and other people in Yukon and British Columbia on environmental and socioeconomic gaps that might need filling for an Alaska Highway gas line.

At the moment, the NPA is a tiny agency with 14 people, Chudczak said. Most are in the head office in Ottawa, with one in Calgary and one in the Yukon capital of Whitehorse. By law, all of the agency’s costs are recoverable from

see NPA page 10
Industry research team finds major variations in marine environment and unexpectedly small fish in areas of planned oil drilling

By ALAN BAILEY

In the summer, from the air, the grey surface of Alaska’s Chukchi Sea, extending out to the horizon, looks monotonously uniform, other than perhaps for a scattering of small ice floes, the remnants of the winter ice pack. But the water below the ocean surface contains some remarkable environmental variation. Or, at least, that is the finding to date of an industry-funded research team, investigating the subsea environment of areas planned for oil and gas exploration drilling by Shell, ConocoPhillips and Statoil.

Dramatic changes

“I’ve never seen a system in which you can have such dramatic changes, environmentally, in such a short distance,” Robert Day, senior scientist with environmental research firm ARB Inc., told the National Marine Fisheries Service’s annual Arctic Open Water Meeting on March 8. Day was referring to differences in the underwater environment between the areas around the ConocoPhillips Devil’s Paw prospect, around the Burger prospect, where Shell plans to drill; and around Statoil’s Chukchi Sea leases. Day referred to the ConocoPhillips area as the “Klondike” area, referencing an earlier name for the ConocoPhillips prospect.

The Klondike area lies about 120 miles west of the Chukchi Sea coastal village of Wainwright. The two other prospects are farther north: The Statoil area is about 100 miles northwest of Wainwright, while Burger lies to the south of the Statoil area and about 60 miles northeast of the Klondike area.

The objective of the industry-funded research is to obtain baseline environmental data; to obtain information needed for permitting and National Environmental Policy Act assessments; and to provide information needed to plan any future industrial operations, Day said. The findings that Day presented to the Open Water Meeting related to research cruises conducted between July and October in the years 2008 to 2010, with research in the Statoil area starting in 2010. However, the research continued in 2011 with an expanded study area, Davis said.

During the cruises, the research scientists used a computer system to merge data from environmental sampling with continuous records of vessel navigation data and other data such as weather information. Data were also obtained from arrays of subsea acoustic recorders.

Day attributed the environmental differences between the three areas in part to a complex interaction between ocean currents, seafloor topography and year-to-year variations in the Arctic weather. At a very simplistic level, the Chukchi Sea, having a sea surface slightly higher at its southern extremity than in the north, can be viewed as a northward inclining table, with relatively warm Bering Sea water flowing north through the Bering Strait, through the Chukchi and into the Arctic Ocean. Day said. That water flow becomes fanned out in an area of large north-south subsea channels, including the Barrow Canyon, off northwest Alaska, and a channel that is more central to the Chukchi Sea shelf. The water tends to flow around some major shoals that form high points in the subsea topography.

During the winter, cold Chukchi Sea water sits under the annual cover of sea ice, resulting in two competing water systems: the cold, static, low salinity water from under the ice, and the warmer, higher salinity water trying to flow north from the Bering Sea. The extent to which the Bering Sea water displaces the cold winter water at a particular location appears to depend on how far south that location is; the relative

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INDUSTRY RESPONSE

ects at Kuparuk. He said geologists, geophysicists, engineers and drillers working the field “tell us we’re opportunity rich in Kuparuk,” but said “we don’t have the kind of investment climate up here that allows us to bring those incremental dollars in. Consequently, we don’t push ahead trying to find a great deal more opportunities up here; we’re just focusing on the opportunities that we have in hand.” And Jepsen said ConocoPhillips would like to see a different tax environment, like that under HB 110, “that is homogenized; it doesn’t try to differentiate between projects."

He urged the committee not “to disturb the system by trying to create favorite children for investments. I think you’re much better off to have a … level playing field for investment decision making.”

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Waters of the Chukchi bring surprises

by ALAN BAILEY
EIA forecasts flat WTI 2012-13 at $106

Henry Hub natural gas spot prices at $2.18 per million Btu lowest average monthly since April 1999, down 32 cents from February

By KRISTEN NELSON

**FINANCE & ECONOMY**

While the U.S. Energy Information Administration expects West Texas Intermediate crude oil prices to remain relatively flat through 2013, averaging about $106 per barrel, it expects Henry Hub spot prices for natural gas to rise in 2013 from the 2012 level. EIA said in its April 10 Short-Term Energy and Summer Fuels Outlook that the Henry Hub spot price for natural gas averaged $2.18 per million Btu in March, down 32 cents from February “and the lowest average monthly price since April 1999.”

The agency expects natural gas prices to average $2.51 per million Btu this year, rising to $3.40 in 2013. Both 2012 and 2013 price forecasts are down from the agency’s March forecast, which called for 2013 prices to average $3.17 this year and $3.96 next year.

**EIA forecasts U.S. crude oil production to increase to 6.02 million bpd this year, the highest level of production since 1998.**

“Prices remain low as production and supplies remain robust,” EIA said.

EIA projects the WTI price discount to average U.S. refiner acquisition cost to narrow from about $7 in the second quarter this year to about $4 per barrel by the fourth quarter of 2013, “as physical pipeline capacity constraints diminish.”

The U.S. refiner acquisition cost of crude oil is expected to average $112 per barrel this year and $110 per barrel in 2013.

**Natural gas production, imports**

Total U.S. marketed natural gas production grew an estimated 4.8 billion cubic feet per day, 7.9 percent, in 2011, “the largest year-over-year volumetric increase in history,” EIA said, with the “strong growth driven in large part by increases in shale oil production.”

The agency said it expects year-over-year production growth to continue this year, but at a lower rate than in 2011, “as low prices reduce new drilling plans.”

EIA said Baker Hughes put the natural gas rig count at 647 on April 5, down from a high in mid-October last year of 936, a reduction which has not yet reflected improved drilling efficiency.

Fewer horizontal natural gas rigs in areas of dry production such as the Haynesville shale probably indicate declines in those areas, the agency said, losses which “are more than offset in the short term by other production from wet plays.”

Gross natural gas pipeline imports are expected to fall to 0.7 bcf a day this year, 7.2 percent, as domestic gas displaces Canadian sources, but EIA said the warm winter in the United States has also added to the decline in imports.

Pipeline gross exports grew by 1 bcf a day last year, primarily to Mexico, and are expected to grow at a slower rate this year and next.

Working natural gas inventories continued to set seasonal record highs due to the warm winter, with working inventories at 2,479 bcf on March 30, up 887 bcf from last year and 934 bcf above the five-year average.

**U.S. crude production growing**

EIA expects crude oil production from areas outside the Organization for the Petroleum Exporting Countries, or OPEC, to increase by $30,000 barrels per day this year and another 180,000 bpd next year, the highest level of production since 1998.

“Prices remain low as production and supplies remain robust,” EIA said. EIA forecasts U.S. crude oil production to increase to 6.02 million bpd this year, the highest level of production since 1998. “The rise in production is driven by increased oil-directed drilling activity, particularly in onshore tight oil formations,” EIA said.

An increase in Lower 48 crude oil production of 450,000 bpd this year will offset declines averaging 30,000 bpd from Alaska and 50,000 bpd from the Gulf of Mexico.

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Contact KRISTEN NELSON

Contact Wesley Loy

**Continued from page 8**

**NPA**

**TransCanada**

There was a time, in the late 1970s and early 1980s, when the NPA had more than 100 staffers. It regulated construction of what’s known as Stage 1, or the “pre-build,” of the gas pipeline in southern Canada to American markets, an NPA fact sheet says.

The project’s long-awaited Stage 2 would link gas reserves at Alaska’s Prudhoe Bay to existing Alberta infrastructure. This is the segment for which TransCanada might make NPA filings by October.

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**Visit the NPA’s website at www.npa.gc.ca**
Bill aims at project-delaying litigation

Rep. Eric Feige seeks bonds from litigants requesting injunctions against development projects; House bill now in Senate Judiciary

By STEFAN MILKOWSKI
For Petroleum News

I n an effort to forestall costly delays to resource development projects, Rep. Eric Feige of Chickaloon is pushing legislation requiring litigants to post bonds covering the cost of lost wages to employees and subcontractors.

"HB 168 seeks to impose a penalty on frivolous suits," Feige wrote in a sponsor statement. "By requiring a bond to be posted in the event of an injunction, the cost to the party bringing the suit is increased.

This bill seeks to level the legal playing field without infringing on any party’s right to bring a legitimate issue to court.

The bond requirement would apply to cases involving an "industrial operation," defined as "construction, energy, or timber activity and oil, gas, and mineral exploration, development, and production."

HB 168 breezed through the House Judiciary Committee last year and passed the House 33-6. It has the support of the Resource Development Council, the Council of Alaska Producers, the Teamsters, and the Alaska State Chamber of Commerce, which has named judicial reform one of three top legislative priorities. The bill also has the support of Gov. Sean Parnell.

"Skin in the game"

Advocates say requiring litigants to have "skin in the game" would discourage groups from suing just to slow projects down and would encourage active involvement early in the permitting process.

"Examples of ideologically-based challenges abound throughout Alaska," wrote RDC’s Carl Portman in testimony on the bill. "The timber industry in Southeast Alaska would be in better shape today if a bond was required before timber sales are enjoined."

Mike Satre of the Council of Alaska Producers testified that the bill would force litigants to recognize the financial implications of their actions and would provide security for Alaskan workers.

Feige testified that he sees HB 168 as a "jobs bill."

"This bill moved out of the Senate Labor and Commerce Committee on March 20. It had its first hearing in the Senate Judiciary Committee on April 11.

Permitting impact?

Committee Chair Sen. Hollis French questioned whether the bill would affect Alaska’s ability to assume permitting primacy from the federal government, by making access to the courts more restrictive in Alaska than federally. He said Rep. Jon Henriksen had vetoed a similar bill in Utah out of concern that it would affect permitting primacy there.

Feige said he didn’t think the bill would affect primacy, and he offered intent language to that effect. French also questioned whether the problem was really as Feige describes. In his sponsor statement, Feige mentioned "several cases" where courts have issued stays or injunctions that delay projects and curtail jobs. In testimony, he mentioned the halted construction of the Pogo Mine in 2004 and an injunction against Shell's offshore drilling project, which he said directly cost him a job.

But those projects all dealt with federal permits, and no one offering public testimony at the April 11 hearing could point to a case in state court where an injunction was later found to be misguided. "The question I keep asking is, Are we doing something wrong that we need to fix?" said French.

In an interview after the hearing, Feige said because companies have so much to lose by an injunction, they often reach settlements. "A lot of stuff never makes it to the court system," he said.

Asked if there were future projects where HB 168 might apply, Feige mentioned the Wishbone Hill coal project near Palmer.

Feige contends that judges are already directed to require bonds from litigants for the cost of damages, and that HB 168 simply directs them to include in their consideration the cost of lost wages to employees and subcontractors. He says judges would still have wide discretion, and that the bill does not change court rules, which would require a two-thirds vote in the Legislature.

Betting on successful outcome

At the Judiciary hearing, critics argued the bill would not affect frivolous lawsuits, which they said a judge would simply dismiss. Instead, it would force litigants with legitimate claims to bet — potentially millions of dollars — on the successful outcome of their cases. "This punishes only Alaskans who bring the strongest cases to court," said Andy Modernow of the Alaska Conservation Alliance.

Tom Waldos, an attorney with Earth Justice, claimed the bill would affect Alaska’s ability to assume permitting primacy from the federal government, by making access to the courts more restrictive in Alaska than federally.

"None of us viewed it as something to hang the bill up on," Feige said later, adding that a reasonable employer would distribute the money.

French held the bill in committee.

Contact Stefan Milkowski at stefanmilkowski@gmail.com
Doyon Drilling worker killed at Nikaitchuq

North Slope Borough police told David James, 56, was struck by falling beam; Doyon, OSHA and NSB police among those investigating

By Lisa Demer

A Doyon Drilling Inc. supervisor was killed the morning of April 9 in an accident on a North Slope offshore drilling pad, Doyon Ltd., a regional Native corporation, said in a written statement.

The company said its board, senior management and staff and Doyon Drilling staff all are saddened and expressed sympathy to James’ family and friends.

“It has been, and always will be, Doyon Drilling’s top priority to send all of our employees home safely,” general manager Ron Wilson said in a statement.

Doyon Drilling is an oil field contractor. The platform is in the Nikaitchuq unit owned and operated by Eni, a major Italian oil company. Production started last February. The field is expected to peak at 28,000 barrels a day, according to the Eni website.

Eni is drilling 32 wells in the area, including 22 from an onshore pad at Ooloktok Point and 30 from Spiy Island. It expects to have drilling completed by 2014. The company says it considers some of the wells to be “leading-edge,” because they extend 4,000 feet vertically and up to 20,000 feet horizontally.

The Nikaitchuq field is Eni’s first as an operator in Alaska.

ALTERNATIVE ENERGY

Utility gets more time on bankruptcy plan

A small Southwest Alaska electric cooperative has been given more time to file an amended bankruptcy reorganization plan.

In a March 28 hearing in Anchorage, U.S. Bankruptcy Judge Donald MacDonald “reluctantly” granted Naknek Electric Association’s motion to be given until June 29 to file the plan.

The co-op in September 2010 filed for Chapter 11 protection from creditors due to complications with a geothermal drilling program.

Naknek Electric, which serves King Salmon and other villages in the Bristol Bay area, embarked on an exploratory geothermal campaign in an effort to find an alternative to burning expensive diesel to generate power.

The co-op said that by the time it filed for bankruptcy, it had incurred about $40 million of debt that was “in one way or another associated with the geothermal project.”

In its initial reorganization plan, filed in September 2011, the co-op proposed possibly selling its drilling rig and discontinuing the geothermal program.

But co-op representatives have continued searching for financing to keep the program alive. In late January, they asked a state legislative committee for $3.2 million to complete the one troublesome geothermal well drilled so far.

“We value our employees very much; they are all dedicated professionals who have worked very hard to help us compete in what is an extremely difficult economic climate.”

Affected employees will have opportunities to apply for other positions within Flint Hills, while employees who end up leaving the company will receive severance packages, Flint Hills says.

The North Pole refinery first went into operation in 1977, a few months after oil started flowing down the trans-Alaska oil pipeline. The refinery, which has gone through several changes of ownership, was expanded over the years, eventually reaching a processing capacity of 215,000 barrels per day. According to the Flint Hills refinery, the refinery now has a maximum capacity of 220,000 barrels per day.

However, Flint Hills has declined to comment on the impact of the crude unit closure on the refinery’s throughput.

High oil costs

But the crude unit closure will involve the loss of 35 to 40 jobs.

“This is the most difficult decision we have had to make in operating this refinery,” said Mike Brose, vice president of Alaska operations and manager of the refinery, when announcing the crude unit closure.

“We value our employees very much; they are all dedicated professionals who have worked very hard to help us compete in what is an extremely difficult economic climate.”

Pipeline lines & downstream

North Pole refinery to close crude unit

Flint Hills says it needs to cut back to a single unit to deal with difficult economics of operating refinery in Alaska’s interior

Flint Hills Resources Alaska is beginning the process of shutting down one of its two operational crude units in its North Pole refinery near Fairbanks in Alaska’s interior, the company said April 10.

The refinery uses as feedstock some of the crude oil passing down the trans-Alaska crude oil pipeline from the North Slope and produces a variety of fuels and other products for use in Alaska.

The refinery is a major supplier of jet fuel for the Ted Stevens Anchorage International Airport, a hub airport for international air freight. The refinery has three crude units, one of which has been shut down since 2010.

Flint Hills says that it will use its remaining crude unit to continue producing jet fuel, gasoline and some specialty fuels for the Alaska market and that it will continue to meet all of its contractual obligations.

Loss of jobs

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High oil costs

But, as oil prices have risen in recent years, the dependency of the refinery on crude oil, both as a feedstock and as a fuel for refining the oil, has taken its toll on the economics of the plant. Flint Hills says that

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Council cites flaws in oil spill plans

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REFINERY CLOSURE

the plant’s remote location also presents economic challenges.

To reduce its operation costs, Flint Hills has been seeking ways of establishing a supply of natural gas as a fuel at the refinery — in August 2011 the company signed a memorandum of agreement with Golden Valley Electric Association to build and operate a liquefied natural gas facility on the North Slope, to enable the trucking of liquefied natural gas to Fairbanks. Flint Hills has also been making modifications to the refinery, to recover heat from the residual oil that it returns to the trans-Alaska pipeline.

Flint Hills also says that the working of the trans-Alaska oil pipeline quality bank, the procedure whereby the value of the oil flowing down the pipeline is adjusted to allow for the different qualities of oil from different North Slope oil fields, operates to the detriment of the refinery. The problem relates to the value assigned to the residual oil that the refinery returns to the pipeline, Flint Hills spokesman Jeff Cook told Petroleum News.

Bose said that the refinery was designed to use crude oil as an energy source.

“Crude oil prices and Alaska North Slope crude prices in particular are very high and are expected to remain that way for the foreseeable future,” Bose said. “In addition, the calculations associated with the quality bank place our refinery in a disadvantaged position. We need to solve these two problems in order to survive, and a single crude unit configuration gives us the best platform to work on these problems.”

By WESLEY LOY
For Petroleum News

An advisory council is raising concerns about proposed oil spill cleanup plans North Slope crude shippers have submitted to state regulators.

Problems include a decrease in contract manpower, and a lack of commercial fishing vessels available to help with cleanup, the Prince William Sound Regional Citizens’ Advisory Council says.

The Valdez-based council is a congressionally mandated nonprofit organization formed after the 1989 Exxon Valdez oil spill. It represents seafood, environmental, Native and recreational interests.

Under state law, oil shippers must have oil discharge prevention and contingency plans, commonly known as C-plans, laying out how they would deploy people and equipment to deal with a major spill.

Shipping companies for North Slope oil producers including ConocoPhillips, BP, ExxonMobil and Chevron, as well as refiner Tesoro, have put in C-plan renewal applications for the foreseeable future.” Bose said. “In addition, the prices are very high and are expected to remain that way for the foreseeable future.”

The proposed C-plans don’t account for a sufficient number of fishing vessels, committing to having only 275 vessels available when ideally about 370 vessels are needed.

The council also questioned the industry’s ability to adequately contain, control and recover the required minimum of 300,000 barrels of oil within 72 hours after an incident. The council analysis said the rapid spread of oil on water wasn’t properly accounted for.

The council also criticized the proposed C-plans for not assigning enough equipment to protect fish hatcheries or other sensitive areas in the event of a spill.

“The overall timing of hatchery protection and sensitive area protection also seems to have slowed down when compared to the 2007 plans,” the council said. ●

Contact Wesley Loy at wloy@petroleumnews.com

Escort tugs need evaluation, council says

Are the tugs used to escort oil tankers in Alaska’s Prince William Sound really up to the job?

The Prince William Sound Regional Citizens’ Advisory Council is raising the question.

The council is calling for tests to make sure the tugs are “sufficiently powerful and stable.”

And the group suggests it’s time to “plan for the possible future phase-in of tugs that meet higher standards.”

The purpose-built tugs operating in support of tankers calling on Valdez to pick up North Slope crude “are now at least 12 years old, and no longer represent state-of-the-art technologies,” the council said in a March 23 submission to the Alaska Department of Environmental Conservation.

The council said it recently funded a study to compare Prince William Sound tugs against other vessels. The group also reviewed a proposed escort vessel system for the oil terminal Enbridge Inc. is pursuing at Kitimat, British Columbia.

Prince William Sound tugs “would not meet the specifications” for the Kitimat terminal, the council said.

Alyeska Pipeline Service Co., which operates the tanker terminal at Valdez, contracts with Crowley Maritime Corp. for a fleet of tugs to escort oil tankers.

see ESCORT TUGS page 14

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Contact editor & masthead at aballey@petroleumnews.com
Qugruk cleanup completed, for now

By ERIC LIDJI
For Petroleum News

Since bringing it under control in March, crews have finished cleaning up a blown out North Slope well, according to the Alaska Department of Environmental Conservation.

A group from Kusquelik Subsistence Oversight Panel Inc., or KSOP, and the village of Nuiqsut visited the site on April 1 and "was satisfied with the work that had been done and said that they did not believe that any further clean up needed to be performed," according to an April 10 DEC situation report. A final inspection team composed of representatives from the North Slope Borough, KSOP, DEC, the Alaska Department of Natural Resources and Repsol toured the pad on April 5 and "agreed that no further clean up actions were required. A team of DEC field monitors left the site on April 6.

Because drilling mud and brackish water can impact tundra plants by changing the salinity of the soil, DEC crews will return to the site this summer for final samples "to confirm the area is clear of residual contamination" and decide on a restoration plan.

A surveying contractor hired by operator Repsol E&P USA Inc. determined that 21,114 gallons of downhole material from the Qugruk No. 2 well sprayed across 23.75 acres of snow-covered tundra, including an area of 16.76 acres misted too lightly to recover.

Alaska Clean Seas, Pacific Environmental Corp and CCI Inc. have been using loaders, excavators, trimmers, skid-steers, hydraulic hammers and snow machines to remove material from the heavier contaminated areas and hand tools in other areas. As of April 10, the crews reported clearing some 6,286 cubic yards of material from the snow-covered tundra around the well site and 2,402 cubic yards of downhole material.

During preliminary clean-up operations before well control, crews removed 116,928 gallons of drilling mud and freshwater from steam used to thaw that mud from the pad. The Qugruk No. 2 well blew out on Feb. 15 when the drill bit hit a shallow pocket of natural gas at about 2,500 feet en route to a deeper oil target at around 7,000 feet.

The gas was diverted away from the rig and crews shut down equipment to avoid igniting gas. The well stopped flowing the next day and there were no injuries, according to DEC.

Following the incident, Repsol suspended its North Slope drilling program and the Alaska Oil and Gas Conservation Commission subsequently withdrew the drilling permits for all three Qugruk pads. Upon request, Repsol reapplied for the permits to drill the Q-1 and Q-4 wells, but decided to plug and abandon the Q-2.

In early March, Repsol restarted drilling operations at its Kachemach 1 ice pad farther south from the Qugruk pads in a geologically dissimilar section of the North Slope.

continued from page 13

ESCORT TUGS

Two tugs accompany each oil-laden tanker through Prince William Sound, with one tug typically tethered to the stern of the tanker, the other towing the tanker to ensure safe passage to the terminals.

The council, in an April 6 letter to Alyeska, recommended “full-scale ballast pull and steering pull tests,” among other steps, to make sure Prince William Sound tugs are fit for escort duty.

In part, the council said, the tugs should be rated for “indirect towing,” whereby the tug can actually turn sideways to brake or control a tanker. The council also recommended upgrades to towline winches aboard the tugs.

The recommendations are based on a council-commissioned analysis from Det Norske Veritas, a Norwegian concern specializing in risk management.
continued from page 4

Housing RQ&A

continued from page 1

SB 192

Senators began working with consultants last summer and work on the bill began in February with hearings. The bill which came out of Senate Resources early March had its first hearing management Finance March 13 and has been on the committee’s agenda pretty continuously since then.

Senate Finance substantially reworked the Resources bill, passing it out April 11. It was expected on the Senate Floor April 12, as this issue of Petroleum News was going to press.

What the bill does

According to highlights from the Senate Bipartisan Working Group, the bill addresses excessive profitability at high oil prices, freezes the state/industry split of profit above $120 a barrel and creates a framework for incentivizing new oil production.

Changes to the bill — the committee adopted version Y on April 11 — included increasing the trigger for incremental production to $90 from $60; extending the reduced tax rates for new production from seven years to 10; and increasing the trigger for when profitability kicks in to $90 from $60.

Special session likely

Gov. Steve Parnell told the Associated Press April 11 that he will call legislators back for a special session to make sure the House has time to evaluate a Senate oil tax bill.

Parnell told AP he also wants action on an in-state gas pipeline bill, as well as on operating and capital budgets and full funding for the state’s performance scholarship program. He said if those items are not completed by the end of session, they could be part of a special session.

The governor told AP that if there is a special session he would prefer that it be “sooner rather than later,” between the end of the session and the end of the month, but said if the Senate bill is “completely different than the language” then that information is gotten to them.

We heard over and over the importance of continued communication and that information is gotten to them. That communication with these coastal communities is extremely important, so that people have a sense they’re being heard, that the issues they’ve brought up are responded to in some fashion, and that information is gotten to them. We heard over and over the importance of continued communication and meetings with communities.

The people of the district off the North Slope and along the northwest coast are split on the issue. There are those that are supportive of the concept and have a sense that it’s done responsibly and we can react accordingly. And there are many that are concerned because of the potential interruption of food security.

I think there’s a way forward. But the one thing we learned in the task force is that the communications with these coastal communities is extremely important, so that people have a sense they’re being heard, that the issues they’ve brought up are responded to in some fashion, and that information is gotten to them. We heard over and over the importance of continued communication and meetings with communities.

The people I represent are most interested in the security of their land, and the Yukon and Kuskokwim rivers that drain into the Bering Sea. Food security is an issue for them.

It’s not that the people of western Alaska don’t want responsible resource development. They do. But they want us to do it right.

Petroleum News: You both advocated for a state coastal management program that gave more power to coastal communities. Why is a program necessary, and what does that mean for the future of the program?

Joule: Just briefly, because we do have a ballot measure that people will have to consider later in the summer. Whether you supported a reauthorization of coastal zone or not, it doesn’t matter what your position is on the ballot measure — you’ll do that inside the voting booth.

If in a couple years there’s buyer’s remorse if the ballot measure doesn’t go forward, because there was not a reauthorization of the coastal zone. I think people are in the process of how we will be.

Petroleum News: Does the language of the ballot measure refer to a specific bill?

Herron: There is a bill (HB 125), introduced by several of us so there was a vehicle in place that was essentially the same as the ballot measure.

Petroleum News: What’s going to be monumental is that we’ve had a completely substitute. I’ve provided it to the sponsor, Rep. Alan Austerman, and the two co-chairs of Resources, and I’ve asked for a hearing, but a hearing has not been scheduled yet.

Petroleum News: Does it concern you to have such complicated and nuanced legislation on a ballot measure, where it has to be summarized in a few paragraphs to voters who might not know the details?

Herron: Well, it’s the process we have. If it’s this or a different subject, yeah, it’s difficult to educate a majority of Alaskans on any issue. This one isn’t going to be any easier than any other one.

Contact Stefan Milkowski at stefan.milkowski@gmail.com

The advice

The Legislative Budget & Audit Committee contracted with PFC Energy for analysis on oil tax issues; Pedro van Meurs also did work for the Senate over the summer and fall and winter.

When Senate Finance heard industry reaction to the bill April 6, Finance co-Chairs Lyman Hoffman, D-Bethel, Paul Berger, R-Fairbanks, and Committee Staffer Rep. Tim K撷取, D-Wasilla, D-YES was prev-

ated assertions by ConocoPhillips Alaska that changes would be required for Alaska’s tax system to provide incentives for investment over a broad range of prices.

Hoffman noted that consultants have said there are no problems with ACES at oil prices of $100 or $110. But both senators worked on fixing ACES at the high end, north of $100 and $110. Are our consultants wrong, he asked?

Scott Jepsen, ConocoPhillips Alaska representative of External Affairs, noted that “the consultants aren’t investing any money into this, this is a group of folks that are looking at the opportunities that we have in the Lower 48 and other places and around the world,” and Alaska does not have the same attractive-

ness for that incremental capital investment as we see in other places.” As of April 9 hearing, Mayer told the committee he noted that in a number of discussions with industry he’d heard remarks that “the committee’s consultants had suggested that it’s not ACES—
Oil & Gas Supply Co. is ‘Amblin for Alzheimer’s’

Oil & Gas Supply Co. said April 10 that it has been a major contributor to Alzheimer’s Resource of Alaska since 2006 and supports programs and services provided by the nonprofit to those individuals affected by Alzheimer’s disease or related dementia in Alaska, or ADRD.

Last year Oil & Gas Supply not only helped sponsor the walk with a major corporate donation, they also started a team and raised an additional $2,300 for the cause. ADRD is a cause that is important to Jackie Brunton, Oil & Gas Supply owner, whose mother was diagnosed with Alzheimer’s years ago. “The education and support I received from this great agency were invaluable to me as a caregiver and gave me the tools I needed to provide my mother with the quality and dignity of life she so deserved,” said Brunton.

This year the walk will be Saturday, May 12 at the Kincaid Chalet. The event is expected to attract up to 300 participants with a fundraising goal of $75,000. All monies raised by the organization stay right here in Alaska, enabling services to be provided throughout the entire state.

To register for the walk or start a team visit https://alaska.myerf.org/fundraiser/Amblin2012/ or to support Brunton’s team click on the Oil & Gas Supply link to the right on the Amblin for Alzheimer’s website. You can also contact Brunton at Oil & Gas Supply, 6108 Tuttle Place, Suite B, Anchorage, Alaska 99507 or call at 907-344-2512 or 250-6170.

Calista shareholder dividends total $4 million

Calista Corp. said April 6 that its board of directors voted April 5 to approve a shareholder dividend distribution totaling $3.99 million to shareholders of record dated March 29. This marks the fifth consecutive yearly dividend increase with distributions since inception at more than $17.4 million. Calista has one of the largest populations of shareholders among the Alaska Native corporations at more than 12,000 individuals. The April distribution equates to $3 per share. Checks were expected to be mailed out by the close of business April 13. “Dividends are only one aspect of the ANCSA mandate to improve the socio-economic lives of shareholders and our communities,” said Michael J. President.

Calista shareholder dividends total $4 million

Calista’s board of directors approved a fourth-quarter dividend of $2 per share, bringing the total dividends distributed since ANCSA to more than $20 per share.

The total dividends paid to shareholders will amount to $4 million. The dividend will be paid on April 13 to shareholders of record at the close of business on March 29. Shareholders will receive $3 per share.

To register for the walk or start a team visit https://alaska.myerf.org/fundraiser/Amblin2012/ or to support Brunton’s team click on the Oil & Gas Supply link to the right on the Amblin for Alzheimer’s website. You can also contact Brunton at Oil & Gas Supply, 6108 Tuttle Place, Suite B, Anchorage, Alaska 99507 or call at 907-344-2512 or 250-6170.

Oil & Gas Supply...
natural gas producer. 

While the Haynesville pushes boldly towards the magic 1 million barrels per day target, the Canol is only just advancing from decades of conventional oil production, fuelled by a war. Norman Wells is a last year’satch which fetched CSS36 million, led by Husky Energy at CSS76 million, with Imperial Oil, Shell Canada and ConocoPhillips Canada, joined by junior explorer MGM Energy, playing key roles. 

By mid-2016 at the latest — when license holders are required to drill their first exploratory well — there should be a clear indication whether the Canol will enter the big time. 

Speculation and competition 

For now, the basin is generating intense speculation and competition. 

John Hogg, MGM Energy’s vice president of exploration, said that when last year’s bidding results were released it “created quite a buzz. … I recognized it was about the new potential of the shales.” He told C1 Energy Group’s Arctic oil and gas symposium in Calgary in March that one of the biggest initial challenges is to overcome the region’s regulatory challenges. 

Hogg said those who have worked in the north over many years “find that it is probably one of the most difficult and unpredictable regulatory regimes (in Canada). The time for reviewing and improving the regulatory process is now; not during the development of the Canol shale resource.” 

He described the Devonian-era Canol shale as a 375 million year old formation, deposited below the water in what was then a warm sea. 

Norman Wells source rock 

The life forms that died created the organic content that made the shale a source rock for the Norman Wells oil field, which has been producing for about 65 years, he said. 

The Canol shale has a high total organic content of 3 percent to 27 percent and an average of 9 percent to 12 percent, which Hogg rated as two to three times the average shale that is exploited in North America. 

He said the resource is liquids-prone and has geochemical characteristics pointing to the production of some oil, with more left to be produced. Hogg said all of the features are “very good when it comes to looking at this shale rock from the point of view of exploration.” 

CSS5 million work commitment 

And MGM has turned its attention to the Canol play, where it has 6362 NWT Ltd. made a work commitment of CSS5 million for three exploration licenses covering about 628,000 acres. 

MGM President Henry Sykes said in a statement in late March the play “continues to show great potential.” “We are currently focused on advancing the regulatory process and operational planning with the intention of drilling a well in the winter of 2012-2013.” “We are also looking for a partner as one option to assist in the development of this exciting shale-oil play,” he said. 

Sykes also said MGM is considering a “a number of alternative means of commercializing” its Mackenzie Delta gas assets, without offering any further hints, although it mirrors the mood among larger operators in Canada’s North who have set aside their hopes of participating in a gas pipeline from the Mackenzie Delta to concentrate on the scramble to enter the oilier Central Mackenzie Valley. 

“The unconventional that we are going after will be more from a liquids perspective than from a gas perspective,” said Clayton Reasor, vice president of corporate and investor relations at ConocoPhillips, whose work commitments involve CSS66.7 million for about 216,000 acres. 

Norman Wells line underutilized 

The Norman Wells oil field was discovered in the 1920s and has produced about 300 million barrels, although current output has dropped by 50 percent to 20,000 barrels per day. 

As a result, a 40,000 bpd Enbridge-operated crude pipeline covering 540 miles from Norman Wells to Zama in northwestem Alberta, and from there to the Edmonton refining hub, is underutilized, helping to spur a shift from conventional dolomite reefs which have failed to yield any new finds to the original source rocks. 

The Canol shales, like their near relatives in the Bakken region, enjoy high porosity and are saturated with liquids, but must be hydraulically fractured because of their low permeability. 

MGM plans involve moving heavy equipment by barge down the Mackenzie River, starting in September. 

Once the land is frozen, MGM has about 100 days to drill, fracture and test a well before the spring thaw. 

MGM has estimated that the cost of drilling, testing and completing its first vertical exploration well could run to CSS25 million. 

Other challenges involve the absence of a winter ice road to the drill sites, a shortage of skilled labor and high standby charges because there is no year-round drilling, along with a minimum regulatory cost of CSS250,000. 

Regulatory phase of 17 months 

Hogg said it is important that holders of exploration rights also need assurances that once they acquire land that they can form a pipeline to market the oil and gas. 

He said the regulatory phase involves six federal, four territorial and two regional regulators or agencies, representing a process stretching over about 17 months. “Any concerns that are raised could stop any portion of the process and could easily cost a full year.” “Despite only preliminary data, Hogg is hopeful the Canol could be twice as productive as other North American shale plays.” 

He told the Arctic symposium that the industry needs a made-in-the-NWT solution to dispose of drilling mud and reclaimed water, drill cuttings and frac fluids and produced water. 

“If we are to bring this project forward, we can’t be transporting all that fluid to Alberta or British Columbia,” Hogg said. It could take up to five years to determine the scope of the play and whether the Canol can overcome its distance from market and northern challenges. 

NWT Industry Minister David Ramsay told the symposium his government is working with the Canadian government to obtaining funding for an all-weather road down the Mackenzie Valley. 

—GARY PARK
to focus on oil rather than natural gas produc-
tion, Hutchings said.

"The principal driver in our desire to sell
these assets at this point is really driv-
ened by that forward strategy, which today
for the company is very much focused on
liquids-rich resource plays," he said, add-
ing that Marathon has no substantive
issue with the current regulatory or fiscal
situation for the Cook Inlet oil and gas
industry.

"With an effective date of Jan. 1, 2012,
the sale includes 17 million barrels of oil
equivalent of net proved reserves across 10
fields in the Cook Inlet, as well as natural
gas storage, and interests in natural gas
pipeline transmission systems," Marathon
said in an April 9 press release. "In 2011
net production averaged approximately 93
million cubic feet of natural gas per day
and 112 barrels of oil per day. Additionally,
Marathon Oil had approximately 12.5 bil-
lion cubic feet of natural gas in storage at
the end of 2011."

The company operates gas fields in the
Beaver Creek, Cannery Loop, Kaslof, Kenai,
Ninilchik, North Trading Bay and Stikine.

The pipeline assets include the Cook
Inlet Gas Gathering System that runs under
the Cook Inlet, the Kenai
Nikiski pipeline on the Kenai Peninsula
and the Beluga pipeline on the west side
of the inlet. The company also owns a gas
storage facility in the Kenai gas field.

The sale does not include Marathon’s
Glacier No. 1 drilling rig, which the com-
pany is marketing separately. And in 2011
Marathon sold its 30 percent share of the
liquefied natural gas plant at Nikiski on
the Kenai Peninsula to ConocoPhillips.

Yet to close

Hutchings said that the sale to Hilcorp
will likely close in the fall, given the time
needed to address issues such as the need
for a regulatory review of the transfer of
ownership of some assets. Hilcorp will
likely retain most of Marathon’s approxi-
mately 62 Alaska personnel, he said.

The financial terms of the sale have not
been disclosed.

However, the acquisition of Marathon’s
assets would appear to be a logical move in
expanding Hilcorp’s already substantial
operations in the Cook Inlet basin.

"It’s something that PFC has ever said either
in formal testimony or in other interac-
tions," Mayer said.

Benchmarking

Referring to a slide benchmarking Alaska
tax rates against other fiscal
regimes, he said what PFC has said is at
$100 per barrel ranges, government take
under ACES is in the mid-70 percent,
$100 per barrel ranges, government take
something that PFC has ever said either in
achieve."

"The sale of Marathon’s Alaska asset
will make Hilcorp and ConocoPhillips the
dominant gas producers in the Cook Inlet
basin. ConocoPhillips operates the Beluga
River and North Cook Inlet gas fields.
Aurora Gas, Armstrong Cook Inlet and
Baucarner Energy also produce Cook Inlet

Cook Inlet milestone

The exit of Marathon from Alaska rep-
resents something of a milestone in the
state’s oil and gas history. The company’s
predecessor, Ohio Oil Co., bought interests
in a number of leases on the Kenai
Peninsula in 1954, with its early assets
covering of the huge Kenai gas field in
1959 and began supplying natural gas to
the Anchorage utility market in 1961.

"In partnership with Unocal (now part of
Chevron), Marathon discovered the
Trading Bay and McArthur River oil fields
offshore in Cook Inlet in 1965. In 1986
Marathon set the Seahead platform, the
largest Cook Inlet offshore platform, for
the McArthur River field. And on the

continued from page 15

SB 192

ty good at $100 a barrel, that it was north
of that where the problem lay, or perhaps
around a particular level of government
take for instance the 75 percent of gov-
ernment take for instance the 75 percent of gov-
ernment take as HB 110 does, or by
reducing government take in more target-
ed ways.

An overall reduction is simpler, he said,
but “the cost of that simplicity is that
one has to move a lot of cash across the
tables or the places in particular Alaska at
the moment is competing with for investment capital.”

Lower 48 states have significantly
closer costs in many cases Alaska, he said,
“and that only enhances their com-
petitiveness compared to Alaska.”

Norway is different than Alaska
because it has an active national oil com-
pany and also participates in equity
through another vehicle, “and is far more
able to ensure constant ongoing invest-
ment in its oil and gas industry taking
those vehicles than a state that doesn’t
have those things has,” Mayer said.

He said PFC has said that “particularly
for new investments, where costs are
very high and projects are economically chal-
lenged, there needs to be significant
movements in government take to enable
those to occur and be incentivized.”

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across much of the central North Slope. The company continued to work, though, Brooks Range Petroleum believes the state needs to give smaller companies incentives to work together, to essentially move up from some of those major companies, like many smaller fish swimming together to appear larger.

**Long-held dream**

If the third phase takes hold, it would fulfill a long-held dream among oil patch entrepreneurs, including John Jay “Bo” Bills Jr. and John Armstrong. They founded the Alaska Venture Capital Group in 1999 after watching majors pass over smaller North Slope fields that would be “company makers” in almost any other part of the country.

The company spent the next five years buying acreage, and then in 2001, it started drilling across the North Slope and creating a joint venture of independents to fund an exploration campaign. In 2006, it created Brooks Range Petroleum to operate activities on behalf of the joint venture. Today, Alaska Venture Capital Group owns leases in the Arctic National Wildlife Refuge, but previous incarnations also included the Calgary independents TG World Energy Inc. and Bow Valley Energy Ltd. (Currently, that’s going to work through Ramshorn Investments eventually bought Bow Valley and ultimately chose to sell its Alaska assets back to the joint venture to focus on the North Sea and Africa.)

**Seven holes in five winters**

Once getting its acreage, partners and financing in place, the company, led by Brooks Range Petroleum quickly became one of the most active explorers on the North Slope.

In 2003, the group focused on the Gwydyr Bay region north of the Prudhoe Bay unit, an area long known to contain numerous smaller fields by traditional standards. It acquired 130 square miles of 3-D seismic in the area and drilled the North Shore No. 1 and Sak River No. 1 wells. While Sak River No. 1 proved to be a dry hole, North Shore No. 1 found 70 feet of oil-charged Ivishak sandstone and flowed at 2,092 barrels of oil per day.

In 2008, the group focused on its leases near Nuiqsut. It shot 220 square miles of 3-D seismic in the area and drilled the North Shore No. 3 delineation well, but did not release results from either well.

That year, the group also acquired the North Trotula Unit that became Mustang.

In 2011, the group returned to Gwydyr Bay, drilling the sak River No. 1A side track and the North Shore No. 3 delineation well that confirmed the presence of the Alaska Venture Group in the North Slope. ^The group began studying development of its East Bank asset in 2007, and then began drilling the North Slope fields that would be “company makers” in almost any other part of the country.

The company spent the next five years buying acreage, and then in 2001, it started drilling across the North Slope and creating a joint venture of independents to fund an exploration campaign. In 2006, it created Brooks Range Petroleum to operate activities on behalf of the joint venture. Today, Alaska Venture Capital Group owns leases in the Arctic National Wildlife Refuge, but previous incarnations also included the Calgary independents TG World Energy Inc. and Bow Valley Energy Ltd. (Currently, that’s going to work through Ramshorn Investments eventually bought Bow Valley and ultimately chose to sell its Alaska assets back to the joint venture to focus on the North Sea and Africa.)

Once getting its acreage, partners and financing in place, the company, led by Brooks Range Petroleum quickly became one of the most active explorers on the North Slope.

In 2003, the group focused on the Gwydyr Bay region north of the Prudhoe Bay unit, an area long known to contain numerous smaller fields by traditional standards. It acquired 130 square miles of 3-D seismic in the area and drilled the North Shore No. 1 and Sak River No. 1 wells. While Sak River No. 1 proved to be a dry hole, North Shore No. 1 found 70 feet of oil-charged Ivishak sandstone and flowed at 2,092 barrels of oil per day.

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The facility would be open to all pro-
ducers as long as capacity existed, and could accommodate additional producers in the future through expansions or back out clauses. The optional credit would allow devel-
opers to take the tax break in return for set terms.

Cooperation is especially important for source-rock development, Thompson said. “If the source rock potential on the North Slope is to be truly unlocked to its full potential, all in industry will need to work together and in unison with the state of Alaska. In particular, one of the biggest challenges facing potential development of thou-
sands of source rock producing wells is the transportation logistics,” he said.

Because source rock development requires more drilling than conventional exploration, Thompson favors multi-well pads spaced about three miles apart and connected by relatively short gravel roads, similar to a scheme outlined by state engineers.

That’s where the Field of Dreams phi-
losophy comes into play, he said.

Because of the logistics of moving rigs, equipment and supplies to that grid of remote pads, Thompson said that plan-
ing and possibly building environment-
ally friendly roads in advance of devel-
opment “could be the single most impor-
tant step to move the momentum of source rock development from this and next year’s ‘proof of concept’ to the fol-
lowing years’ full-scale, rapid develop-
ment in the source rock faraway.”

The Thompson Plan

Additionally, Thompson proposed six other ideas for improving North Slope access.

Those include big issues such as reducing or eliminating or bracketing the progression rate on production taxes to give operators more of the upside during high oil prices, and fiscal certainty for future natural gas production to allow producers to reclaim costs.

It also includes two issues unique to independents. The first is extending the Smaller Producer Tax Credit to 2021. The credit pays up to $12 million per year to companies that produce less than 50,000 barrels of oil equivalent per day and (an increasingly smaller) credit for companies that produce up to 100,000 barrels of oil equivalent per day), but is set to expire in 2016. The second is allowing exploration companies to be fully reimbursed for tax credits collected before production begins, rather than at 50 percent.

Thompson also supported Gov. Sean Parnell’s proposal for a 30 percent credit for well work to encourage infield devel-
opment at legacy fields, and proposed a three-year tax-holiday for viscous oil pro-
duction brought online by 2016 and a five-year tax-holiday for unconventional shale and low permeability developments brought online by 2021.

The BRPC management team

Today, Alaska Venture Capital Group is led by Managing Director and former Arctic Pipeline Group President Mark Edger Dune.

Brooks Range Petroleum is lead by Darrah, its president and chief executive officer, and by Armfield, its chief operat-
ing officer. The management team also includes:

- Vice President of Exploration Larry Vendl, who worked on the delineation and development of Prudhoe Bay in the 1980s and helped BP develop the Milne Point unit;

- Chief Geophysicist Larry Smith, who came to Alaska in 1997 as part of the team
Union Oil Co. of California assembled to reinvestigate its exploration in the Cook Inlet basin;

- Senior Geoscience Advisor Doug Hastings, who played a role in the discov-
er of the Alpine and Tarn fields for ARCO Alaska during its 25 years on the North Slope;

- Engineering and Development Manager Mark Wiggin, a 30-year veteran of the Slope;

- Controller Tom Hahmern, who managed development projects in Ukraine before working for the Arctic Builders Source and Mikunda Cotrell Accounting & Consulting.

- Drilling Manager Dan Shearer, another 30-year veteran of the Alaska oil and gas industry who helped bring the Alpine field online during his time with M-I Swaco.

- Special Projects Manager Laurette Rose, who splits time between the North Slope during the winter months and Anchorage for the remainder of the year for the company.

He said the commercial viability of the MGP has diminished, but the project “must be competitive with new sources of supply to North America” to proceed.

NWT Premier Bob McLeod said the scaling back will have a significant impact on the Beaufort region, where businesses have invested heavily in antic-
ipation of a pipeline that could generate billions of dollars.

APG President Bob Reid told a Calgary conference in February that the MGP was not economic at then-prevail-
ing gas prices of US$4, which have since shrunk by 50 percent, but he held out hope that the gas might be needed by 2020. In November, the National Energy Board also forecasted prices strong enough to justify developing Arctic gas by 2020.

But the ConocoPhillips spokesman in Canada said the forecasts “don’t look

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