Spartan 151 loaded

Escopeta’s jack-up rig on heavy lift vessel, scheduled to sail March 18

By ERIC LIDJI
For Petroleum News

Es
copeta Oil has loaded the Spartan 151 jack-
up rig onto a heavy lift vessel at a dock in
Freeport, Texas. The vessel is scheduled to set sail
on Friday, March 18, Escopeta President Danny
Davis told Petroleum News March 17 as this edi-
tion went to press.

It will be the first time in more than a decade
that a jack-up rig is headed to Alaska. But
Escopeta must overcome a few more hurdles
before it can begin its exploration campaign in
upper Cook Inlet.

The ship will sail around the tip of South
America on its way to Cook Inlet. Once the jack-
up is unloaded, it must be outfitted with additional
equipment before it can begin drilling.

On March 9, two officials from the Alaska Oil
and Gas Conservation Commission flew to Texas
to inspect the Spartan 151 but, as expected, said
they needed to inspect it again after it arrives in
Alaska and blowout prevention equipment is
installed and tested.

In February, Davis announced Escopeta was
purchasing a 15,000-pound blowout preventer to
use on the Spartan 151, a major step-up in the
equipment previously used on the rig in the Gulf of
Santo.

The ship must sail around the tip of South
America on its way to Cook Inlet.

BRPC spuds North Tarn

Joint venture begins work on the only North Slope exploration well for 2010-11

By ERIC LIDJI
For Petroleum News

Brooks Range Petroleum Corp. spud its North
Tarn No. 1 exploration well in the central North
Slope of Alaska on March 13, the local independent
said.

North Tarn No. 1 is on state land east of the
Miluveach River, about two miles west of the
Kuparuk River unit. BRPC spud the well using
Nabors rig 9ES and accessed the well site using a
winter ice road and pad system built by Peak Oilfield
Services.

BRPC plans to drill the well to a total measured
depth of 6,640 feet to target both the Brookian for-
mation and the deeper Kuparuk formation. The
Brookian is the same formation producing at Tarn,
the Kuparuk River unit satellite just to the south,
while the Kuparuk is the main formation producing at
the prolific Kuparuk River unit to the east.

BRPC estimates that the Brookian reservoir could
contain some 35 million barrels of oil and that the
Kuparuk reservoir could contain an additional 6 mil-
lion barrels of oil. BRPC previously told Petroleum
News that it believes the smaller Brookian formation
presents a better bet for initial development because
of the complex geology of the Brookian.

BRPC hopes to complete operations at North Tarn
before the end of 2011.

Keeping all options open

ConocoPhillips plans to preserve Cook Inlet LNG plant for possible future use

By ALAN BAILEY
Petroleum News

When ConocoPhillips announced in February that it
would close the LNG plant that it operates on Alaska’s
Kenai Peninsula, the company said that it would begin moth-
balling the plant after it offloads its last consignment of LNG,
probably in April or May. And at an Anchorage Energy Task
Force meeting on March 15 Dan Clark, manager of Cook Inlet
assets for ConocoPhillips Alaska, said that the company plans to
put the plant into a “preserved condition.”

“Our intent is to preserve the plant so that whatever future
opportunities might come up, whether it be future exports or
an import situation, the plant would be in a position to be ready,”
Clark said. Those opportunities could include conversion of the
facility for importing LNG, to bolster local utility gas produc-

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SIDEBAR, Page 27: Accommodating Susitna hydropower

Fiscal framework negotiations next for Mackenzie Gas Project

BP starting heavy oil facility to test production feasibility

SIDEBAR, Page 26: Those pesky oil bacteria at work

ALASKA SHALE REPORT
9  Why Alaska sees hope in source rocks
State petroleum geologist tells lawmakers that North Slope source rocks resemble some of the hottest shale plays in North America
9  Duncan: Our timing was fortuitous
10  Oil makes a grab for shale crown
11  Great Bear scored, but didn’t win it all
Although Great Bear well-positioned, Duncan and Decker say there’s plenty of room for other players in North Slope shale plays
12  Brooks Range joins Alaska shale game
14  Twenty new drilling rigs not impossible
15  Cook Inlet companies eye unconventionals
16  USGS assessing unconventional resources
Agency investigating Alaska potential for developing unconventional plays such as shale oil, shale gas, CBM

ALTERNATIVE ENERGY
5  Troubled Alaska power utility forges on
Naknek Electric, mired in bankruptcy, obtains permit to drill second geothermal well as flow testing continues on initial hole

EXPLORATION & PRODUCTION
8  Doyon plans new Nenana seismic survey

FINANCE & ECONOMY
5  Parnell: Investment goal of tax change
Governor defends changes in ACES, calls $10B loss ‘fantasy scenario’ based on no increased investment, no legislative action
8  Marks: Progressivity dysfunctional
22  Miller CEO hails Alaska energy climate
Parent company of Cook Inlet Energy announces receipt of $2 million state payment; also recoups $1.5M in tariff deal

GOVERNMENT
4  Doogan: Let ACES tax system ride
Anchorage Democrat says credits show companies using system, believes state should hold off on changes, see what companies do next
5  Canada’s northern regulatory cost burden
21  Salazar names ocean energy advisory committee members
21  Ulmer appointed to chair of USARC
22  ACMIP issues still at play in Juneau

PIPELINES & DOWNSTREAM
7  Industry watchdog doing maintenance audit
Review will assess upkeep at Valdez Marine Terminal; former Alyeska Pipeline executive Dan Hisey hired to write report due in June

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## Alaska - Mackenzie Rig Report

### 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>
</tr>
</thead>
<tbody>
<tr>
<td>Doyon Drilling</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Deico 1250 U1</td>
<td>14 (SCR/TD)</td>
<td>Prudhoe Bay W-202</td>
<td>BP</td>
</tr>
<tr>
<td>Sky Top Bremer NE-12</td>
<td>15 (SCR/TD)</td>
<td>Kuparuk 21-106</td>
<td>ConocoPhillips</td>
</tr>
<tr>
<td>Deico 1000 U1</td>
<td>16 (SCR/TD)</td>
<td>Milne Point MPC-2201</td>
<td>BP</td>
</tr>
<tr>
<td>Deico 12000 UEBD</td>
<td>19 (SCR/TD)</td>
<td>Alpine CD3-125</td>
<td>ConocoPhillips</td>
</tr>
<tr>
<td>OIME 2000 TS</td>
<td>141 (SCR/TD)</td>
<td>Alpine CD3-188</td>
<td>ConocoPhillips</td>
</tr>
<tr>
<td>TSM 7000 Arctic Wolf #2</td>
<td></td>
<td>Going to Nisku, AB</td>
<td>Fee/Available</td>
</tr>
</tbody>
</table>

### Nabors Alaska Drilling

<table>
<thead>
<tr>
<th>Rig Type</th>
<th>Rig No.</th>
<th>Rig Location/Activity</th>
<th>Operator or Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Trans-cean rig</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CDX-1 (CT)</td>
<td></td>
<td>Stacked, Prudhoe Bay</td>
<td>Available</td>
</tr>
<tr>
<td>AC Coiled Hybrid</td>
<td>CDX-2</td>
<td>Kuparuk 1E-08</td>
<td>ConocoPhillips</td>
</tr>
<tr>
<td>Deico 1000 U1</td>
<td>2-ES</td>
<td>Prudhoe Bay Stacked out</td>
<td>Available</td>
</tr>
<tr>
<td>Deico 1000 U1</td>
<td>9-ES (SCR/TD)</td>
<td>Mobilizing to North Tan #1</td>
<td>Brooks Range Petroleum</td>
</tr>
<tr>
<td>Oilwell 700 E</td>
<td>4-ES (SCR)</td>
<td>Milne Point MP-65</td>
<td>BP</td>
</tr>
<tr>
<td>Deico 1000 U1</td>
<td>7-ES (SCR/TD)</td>
<td>Prudhoe Bay DS 05-07</td>
<td>BP</td>
</tr>
<tr>
<td>Oilwell 2000 Hercules</td>
<td>14-E (SCR)</td>
<td>Prudhoe Bay Stacked out</td>
<td>Available</td>
</tr>
<tr>
<td>Oilwell 2000 Hercules</td>
<td>16-E (SCR)</td>
<td>Prudhoe Bay Stacked out</td>
<td>Available</td>
</tr>
<tr>
<td>Oilwell 2000 Hercules</td>
<td>17-E (SCR/TD)</td>
<td>Prudhoe Bay Stacked out</td>
<td>Available</td>
</tr>
<tr>
<td>Emisco Electroid Gest - 2</td>
<td>18-E (SCR)</td>
<td>Stacked, Deadhorse</td>
<td>Available</td>
</tr>
<tr>
<td>Emisco Electroid-Verso TD3</td>
<td>22-E (SCR/TD)</td>
<td>Stacked, Milne Point</td>
<td>Available</td>
</tr>
<tr>
<td>Emisco Electroid-Verso TD3</td>
<td>28-E (SCR)</td>
<td>Stacked, Deadhorse</td>
<td>Available</td>
</tr>
<tr>
<td>Academy AC Electric Carrying 1050</td>
<td>105-E (SCR/TD)</td>
<td>Stacked at Deadhorse</td>
<td>Available</td>
</tr>
<tr>
<td>Academy AC Electric mixing 1060</td>
<td>196-E (SCR/TD)</td>
<td>Stacked at Deadhorse</td>
<td>Available</td>
</tr>
<tr>
<td>OIME 2000</td>
<td>24-E</td>
<td>Gilikok Point OP 16-09</td>
<td>ENI</td>
</tr>
</tbody>
</table>

### Nordic Calista Services

<table>
<thead>
<tr>
<th>Rig Type</th>
<th>Rig No.</th>
<th>Rig Location/Activity</th>
<th>Operator or Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Superior 700 U1</td>
<td>1 (SCR/TCD)</td>
<td>Prudhoe Bay Drill Site PT40L1</td>
<td>BP</td>
</tr>
<tr>
<td>Superior 700 U1</td>
<td>2 (SCR/TCD)</td>
<td>Prudhoe Bay Drill Site S-01C</td>
<td>BP</td>
</tr>
<tr>
<td>Icaco 990</td>
<td>3 (SCR/TCD)</td>
<td>Kuparuk Well 2V-09</td>
<td>ConocoPhillips</td>
</tr>
</tbody>
</table>

### North Slope - Offshore

#### Nabors Alaska Drilling

<table>
<thead>
<tr>
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<th>Rig Location/Activity</th>
<th>Operator or Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>OIME 1000</td>
<td>19-E (SCR)</td>
<td>Oooguruk ODST-46i</td>
<td>Pioneer Natural Resources</td>
</tr>
<tr>
<td>Oilwell 2000</td>
<td>33-E</td>
<td>Prudhoe Bay Stacked out</td>
<td>Available</td>
</tr>
</tbody>
</table>

### Cook Inlet Basin – Onshore

#### Aurora Wolf Service

<table>
<thead>
<tr>
<th>Rig Type</th>
<th>Rig No.</th>
<th>Rig Location/Activity</th>
<th>Operator or Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Francis 300 Sts. Explorer II</td>
<td>AWS 1</td>
<td>Stacked out on the west side of Cook Inlet near Tyonek</td>
<td>Available</td>
</tr>
</tbody>
</table>

### Cook Inlet Energy

<table>
<thead>
<tr>
<th>Rig Type</th>
<th>Rig No.</th>
<th>Rig Location/Activity</th>
<th>Operator or Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Atlas Copco RD20</td>
<td>34</td>
<td>Undergoing winterization at W. McArthur River Unit</td>
<td>Cook Inlet Energy</td>
</tr>
</tbody>
</table>

### Doyon Drilling

<table>
<thead>
<tr>
<th>Rig Type</th>
<th>Rig No.</th>
<th>Rig Location/Activity</th>
<th>Operator or Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>TSM 7000 Arctic Fox</td>
<td>1</td>
<td>Beluga Stacked</td>
<td>Available</td>
</tr>
</tbody>
</table>

### Marathon Oil Co. (Inlet Drilling Alaska labor contractor)

<table>
<thead>
<tr>
<th>Rig Type</th>
<th>Rig No.</th>
<th>Rig Location/Activity</th>
<th>Operator or Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Taylor</td>
<td>Glacer 1</td>
<td>Mowing to stack out in Kamai</td>
<td>Available</td>
</tr>
</tbody>
</table>

### Cook Inlet Basin – Offshore

#### Nabors Alaska Drilling

<table>
<thead>
<tr>
<th>Rig Type</th>
<th>Rig No.</th>
<th>Rig Location/Activity</th>
<th>Operator or Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Continental Emisco E3000</td>
<td>273</td>
<td>Stacked, Kamai</td>
<td>Available</td>
</tr>
<tr>
<td>Francis</td>
<td>26</td>
<td>Stacked</td>
<td>Available</td>
</tr>
<tr>
<td>EDCO 2100 E</td>
<td>429-E (SCR)</td>
<td>Stacked, removed from Osprey platform</td>
<td>Available</td>
</tr>
<tr>
<td>Regulator 850</td>
<td>129</td>
<td>Kamai Stacked out</td>
<td>Available</td>
</tr>
</tbody>
</table>

### Baker Hughes North America rotary rig counts*

<table>
<thead>
<tr>
<th>Rig Type</th>
<th>Rig No.</th>
<th>Rig Location/Activity</th>
<th>Operator or Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>M-11 StavHead Platform</td>
<td>408</td>
<td>Alaska’s North Slope</td>
<td>Chevron</td>
</tr>
<tr>
<td>A</td>
<td>11320</td>
<td>National 110 A Coil tubing cleanout planned off Platform</td>
<td>XTO Energy</td>
</tr>
<tr>
<td>1TD</td>
<td>110</td>
<td>National 110 C (TD)</td>
<td>XTO</td>
</tr>
</tbody>
</table>

### Mackenzie Rig Status

#### Canadian Beaufort Sea

<table>
<thead>
<tr>
<th>Rig No.</th>
<th>Rig Location/Activity</th>
<th>Operator or Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>SDC Drilling Inc.</td>
<td>SDC CANMAR Stand Rig #2 SDC</td>
<td>Set down at Roland Bay</td>
</tr>
</tbody>
</table>

### Central Mackenzie Valley

<table>
<thead>
<tr>
<th>Rig No.</th>
<th>Rig Location/Activity</th>
<th>Operator or Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oilwell 500</td>
<td>51</td>
<td>Has left the NWT</td>
</tr>
</tbody>
</table>

---

*This rig report was prepared by Marti Reeve.*

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**The Alaska - Mackenzie Rig Report**

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**Baker Hughes North America rotary rig counts**

<table>
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<th>Operator or Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>US</td>
<td>1,171</td>
<td>1,707</td>
<td>1,407</td>
</tr>
<tr>
<td>Canada</td>
<td>628</td>
<td>625</td>
<td>479</td>
</tr>
<tr>
<td>Gulf</td>
<td>25</td>
<td>25</td>
<td>49</td>
</tr>
</tbody>
</table>

**Highest/Lowest**

<table>
<thead>
<tr>
<th>Rig Type</th>
<th>Rig No.</th>
<th>Rig Location/Activity</th>
<th>Operator or Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>US/Highest</td>
<td>4530</td>
<td>December 1981</td>
<td>Baker Hughes</td>
</tr>
<tr>
<td>US/Lowest</td>
<td>488</td>
<td>April 1999</td>
<td>Baker Hughes</td>
</tr>
<tr>
<td>Canada/Highest</td>
<td>558</td>
<td>January 2000</td>
<td>Baker Hughes</td>
</tr>
<tr>
<td>Canada/Lowest</td>
<td>29</td>
<td>April 1992</td>
<td>Baker Hughes</td>
</tr>
</tbody>
</table>

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*The Alaska - Mackenzie Rig Report is sponsored by:*
Doogan wants to let ACES tax system ride

Anchorage Democrat says credits show companies using system, believes state should hold off on changes, see what companies do next

By STEVE QUINN
For Petroleum News

S
State Rep. Mike Doogan is used to being in the minority. After all, he’s a Democrat in Alaska. Doogan arrived to the Capitol for his first term in 2007 armed with his signature sarcastic touch that can lighten a tense mood created by the divisive oil and gas tax debate. The man who once invoked the term “hum-fuzzled” in a previous tax discussion now sits on the House Finance and Legislative Budget and Audit Com- mittees. The Finance Committee has begun reviewing Gov. Sean Parnell’s tax rewrite plan, House Bill 110. Doogan sat down with Petroleum News to discuss oil and gas issues.

Petroleum News: There are a lot of ideas floating around the building about what needs to be done with the state’s tax system. What do you feel should be done right now?

Doogan: To be honest with you I think it should be left alone right now. I’m not sure where the dividing lines are, but we have written those taxes a lot. In my view we should wait and see what they do. We know some things that we’ve done are working to the extent that we will split out nearly a billion dollars in tax rebates both for the big producers and smaller producers out there trying to find oil. We have no idea what they’ve done. If you decide you’re going to do something because you want to have a certain affect and you don’t wait to see whether it has that affect, you’re just wasting your time. What we’ve done is making some pretty substantial changes in the new oil tax regime. And it’s my view it’s time to see what they do first.

Petroleum News: That was the argument against having ACES break up the bill, I’ve sat in a couple of committee meetings, I still don’t know what it’s going to be. Doogan: I wouldn’t have argued with that position at that time. We had a very popular governor who wanted a change. They were capable of making rational arguments in favor of making those changes. It was a combination of policy and politics just like anything else. I decided to go along with that and I did. Now we have a governor elected for the first time and he wants a change, but he doesn’t have the kinds of arguments in favor of change that she did. I haven’t actually been able to sit and listen to the entire case being made yet, but so far what I’ve heard and what I’ve read, it is not convincing to me.

Petroleum News: The other argument against what’s going on is that it’s moving too fast, pushed through committees without enough discussion.

Doogan: I’ve got to tell you. The way the House Resources Committee handled the ACES discussion with the exception of LB&A before you guys were there was a no recommendation on that bill (four no recommendations and one amend). In talking to my colleagues in that committee, no one seemed to under- stand what it would do or whether it was a good idea. They sort of got pushed pretty hard by leadership to move that bill along.

Petroleum News: ACES only took 39 days with three committees on each side hearing the bill, plus a full day of discussion with LB&A before you guys gavelled in. That’s pretty quick, too, isn’t it?

Doogan: Yeah, but the issues were a lot more clear cut in ACES. It wasn’t complicated. As I sit here now, I’ve read the bill, I’ve sat in a couple of commit- tees, I don’t understand what it’s going to cost the state, or that it’s going to cost that much and what it’s going to do. The ACES discussion with the exception of the Senate when you would click in the higher tax rates, it wasn’t complicat- ed. It was to that extent to what it was you were doing and what effect it would have.

Petroleum News: Last year the Legislature found creative ways to drive business to Cook Inlet. Are there some creative options beyond cut this and drop that?

Doogan: With Cook Inlet, you’ve got a pretty small basin. You sort of know where you are likely to find oil and gas. The problems there aren’t discovering stuff. The problem is what do you do with it, once you’ve got it. Right now we are pricing ourselves out of the market and I think we can absorb. Once the plant in Kenai shuts down, you’re going to have a lot more hydrocarbons than you’ll know what to do with. The problem we’ve got on the North Slope is that the oil production keeps going down 5, 6 or 7 percent every year. That’s going to be a problem because you’re not going to be able to run the pipeline. State revenue, employ- ment, a lot of things are going to suffer because of that. There is the possibility you are going to produce oil offshore. That oil is presumptively, they will have to build a spur and run that oil down the trans-Alaska pipeline. If you are capable of competitive production in NPF-A, that’s still more oil. Then you’ve got heavy oil. The situation on the North Slope is not that there is not enough oil. The problem is the producers want more money to produce it. That’s not a function of their cost, though it is going to be more expensive to produce the heavy oil. What they want is a lot more money to do what they would do otherwise. Their rap is Alaska, you’re pricing yourself out of the market. My response is good luck producing that oil on Sakhir Island when the political system goes south. Have fun in Venezuela. Have a good time when you’re in places where you’ve got to air- lift your employees out of the area because they are getting shot at.

Petroleum News: You’ve got findings with the federal government. Every state has them. But you’ve got these, regardless of what side of resource argument you’ve on, it inhibits the state’s ability to put oil up in the pipeline. What would you like to see this administration do?

Doogan: It needs to take a more real- istic view of what oil production in Alaska is. Among other things, how it is now. It’s pretty cheap oil. It’s very secure oil. It’s expandable oil. You can get more if you put more effort into it. A national

...
The Canadian government is pondering ways to improve its northern regulatory processes, a federal official told a northern gas symposium in Calgary earlier in March where participants got a detailed insight into the costs and challenges faced by E&P companies.

Stephen Traynor, director of resource policy and programs for Indian and Northern Affairs Canada, said an action plan announced last May by then-Indian and Northern Affairs Minister Chuck Strahl has been allocated C$11 million over two years to achieve a more efficient and effective regime through legislative and regulatory changes.

He said environmental monitoring programs will also be enhanced in the Northwest Territories and Nunavut, where C$8 million will be spent over two years.

"There no way that we can be as competitive, the state needs to create new opportunities for new fields," he said.

PROGRESSIVITY Bracketed

Progressivity is also bracketed in the governor's bill. The bracket proposal for progressivity is that in U.S. tax rates: A 15 percent rate is charged on the first portion of income; higher rates are only paid on portions of higher income.

"Progressivity is also bracketed in the governor's bill, the bracket proposal for progressivity is like that in U.S. tax rates: A given rate is charged on the first portion of income: higher rates are only paid on portions of higher income."—Gov. Sean Parnell.

Paradise going down

The bill breaks out new production from fields that aren't currently in units — for a lower base tax rate, 15 percent compared to 25 percent for existing fields, to encourage exploration.

"The state has a world-class resource and unless its tax rate is competitive, the state won't attract capital to develop that resource, he said.

Uncertain passage

Obtaining a permit for any drilling or seismic program is more than C$250,000, Hogg said, adding: "Both the regulatory cost and the timelines are, we think, a deterrent to industry and there are many regulators (federal, territorial and local) compared to other Canadian regimes.”

He said approval for an exploratory well in the NWT can take six to 15 months, compared with six to eight weeks in Alberta, while permitting a seismic program can take four to 12 months in the north, compared with two months in Western Canada.

Contact Gary Park through publisher@petroleumnews.com
Troubled Alaska power utility forge on

Naknek Electric, mired in bankruptcy, obtains permit to drill second geothermal well as flow testing continues on initial hole

By WESLEY LOY
For Petroleum News

A small electric cooperative in south-western Alaska has obtained a state permit to drill a second geothermal well.

Meanwhile, work continues on the utility’s first well — a project that forced the Naknek Electric Cooperative into Chapter 11 bankruptcy reorganization due to cost overruns.

The co-op is attempting to forge ahead in hopes of establishing a geothermal energy source, providing relief from the high cost of diesel to generate electricity. Naknek Electric serves the villages of King Salmon, Naknek and South Naknek in the salmon-rich Bristol Bay region.

Testing first well

A challenge for the utility has been perfecting its first well, to include flush-out drilling mud and cuttings and testing the well’s flow and temperature to determine its strength as a geothermal producer.

To complete the job, Naknek Electric needed to borrow additional money despite its bankruptcy filing.

In December, a bankruptcy judge in Anchorage approved a $1.5 million loan from the National Rural Utilities Cooperative Finance Corp., a private, nonprofit lender based in Herndon, Va.

The same lender financed Naknek Electric’s purchase of a rig to carry out the co-op’s plan to drill multiple geothermal wells. According to a “status report” the co-op filed Feb. 24 in the bankruptcy court, Naknek Electric used the loan to purchase, ship and operate a compressor and air booster to clean out the well.

“Over the last three weeks, the Debtor has boosted water from as deep as 4,500 feet and expects to reach the 7,000 feet level and the slotted liner within the next week,” the status report said. “The water being pumped from the well is very dirty — the Debtor believes that is a good sign.”

The report indicates it’s not yet clear whether Naknek Electric is on a successful “geothermal path, or will end up with an “all diesel outcome.”

Permit for second well approved

The Alaska Oil and Gas Conservation Commission, which regulates drilling, on Feb. 8 approved a permit for a second exploratory geothermal well — the Naknek G-2 well. But drilling has not yet begun on the second well, as the rig remains over the G-1 well while testing proceeds, said Erik LeRoy, an Anchorage attorney representing Naknek Electric in the bankruptcy case.

“Within a month, we’ll have the answer as to whether we have a viable well there,” LeRoy told Petroleum News. The G-1 well site is a few miles north-east of King Salmon.

Naknek Electric hasn’t yet have the financing to start a second well, LeRoy said.

The co-op has mapped out a plan to obtain financing. In court filings, the utility has said it intends to apply for a $52 million loan guarantee from the U.S. Department of Agriculture’s Rural Utilities Service.

The co-op would then apply to the Federal Financing Bank, a government corporation, for a loan backed by the Rural Utilities Service guarantee, the Feb. 24 status report said.

Naknek Electric filed for Chapter 11 protection from creditors on Sept. 29, 2010, citing assets of $10 million to $50 million and liabilities in the same range.

Unexpected costs and other problems with the geothermal drilling venture precipitated the filing.

The co-op began looking at geothermal several years ago, as the boundary of the volcanic Katmai National Park and Preserve is just a few miles from NEA’s electric lines.

Its vision is to build a 10-megawatt geothermal power plant to supply villages in the region.

The co-op’s residential and business members in December took a vote signaling continued support for the geothermal project.

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continued from page 5

TAX DEBATE

another issue.

Senate Finance Committee co-Chair Bert Stedman, R-Sitka, has said that there are reports on fiscal issues which won’t be ready until June, well after the end of the session April 17.

Austerman said the Legislature probably wouldn’t call itself back into session — a situation in which all issues are on the table — but would wait for the governor to call a special session and set the agenda.

He said that if the ACES revision passes the House and the Senate is just a few days from completion, “it could happen that we extend the session.” But if the reports are needed or if the bill is bogged down in the Senate, Austerman said, a special session later in the summer makes sense.

He said preliminary discussions indicate a preference for waiting until after the reports are in, or just before they are due so that the Legislature would be in session when they come out.

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JACK-UP RIG
Available for offshore drilling in Cook Inlet

> Arrives Cook Inlet early May 2011
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> Drilling depth rating: 20,000 ft.
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> 2,000 HP draw works
> Top drive, Varco TDS-3
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Contact Kristen Nelson
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PETROLEUM NEWS • WEEK OF MARCH 20, 2011

6

A L T E R N A T I V E  E N E R G Y
Industry watchdog doing maintenance audit

Review will assess upkeep at Valdez Marine Terminal; former Alyeska Pipeline executive Dan Hisey hired to write report due in June

By WESLEY LOY
For Petroleum News

A nonprofit organization that acts as watchdog over Alaska’s oil tanker port at Valdez is undertaking a “maintenance audit” of the facility. The Valdez Marine Terminal is where tank ships pick up loads of North Slope crude oil for delivery to predominantly West Coast refineries.

The Prince William Sound Regional Citizens’ Advisory Council, based in Valdez, decided at its September 2010 board meeting to conduct the audit of maintenance practices at the terminal. Recent problems along the 800-mile oil pipeline that ends at Valdez helped inspire the maintenance audit, said RCAC spokesman Stan Jones.

Those problems include an extended shutdown of the pipeline in January following discovery of an oil leak at Pump Station 1 on the North Slope, and an overflow of crude from a holding tank in May 2010 at Pump Station 9 south of Fairbanks.

The RCAC, a congressionally mandated organization created after the 1989 Exxon Valdez oil spill, doesn’t have oversight of the pipeline, just the terminal. The council says it has identified a number of maintenance concerns at the facility.

Anchorage-based Alyeska Pipeline Service Co. operates both the pipeline and terminal on behalf of owners BP, ConocoPhillips, ExxonMobil, Chevron and Koch Industries.

An Alyeska spokeswoman did not respond to a request for comment on the maintenance audit.

Two-stage review

“Staff and volunteers became concerned about the status of maintenance at the VMT after a number of perhaps maintenance issues became visible,” an RCAC briefing paper on the maintenance audit says. “As a whole, these concerns appear to be associated with deferral of preventive maintenance.”

The concerns have to do with certain valves, the terminal’s electrical systems, the loading arms that deliver crude to tankers, the condition of storage tanks and the integrity of “secondary containment cells.”

The briefing paper also notes “the considerable turnover in VMT staff during the past three years.”

Jones said the maintenance audit will occur in two stages. First will be a review of maintenance “paperwork” to gain a sense of terminal upkeep.

Then comes selection of a couple of major systems at the terminal for a closer, physical examination, Jones said.

The RCAC has awarded a contract to Dan Hisey of Bellingham, Wash., to conduct the maintenance audit. Hisey is quite familiar with the terminal, having previously worked as chief operating officer for Alyeska. He left the firm in 2005.

In a March 15 interview with Petroleum News, Hisey said Alyeska, when it renewed the pipeline right of way in 2003 for another 30 years of operation, adopted a process known as “reliability-centered maintenance” or RCM. It was a step Hisey said he endorsed while at Alyeska.

RCM is a respected maintenance strategy generally defined as a way to ensure that assets keep doing what their users want them to do.

The maintenance audit will seek to verify that systems at the Valdez Marine Terminal are receiving proper maintenance either through RCM, for the larger systems, or “other maintenance paradigms” used for smaller and less complicated systems, the RCAC’s briefing paper says.

Hisey said he didn’t have any specific systems in mind for up-close examination.

Some important systems at the terminal deal with power generation, vapor control, treatment of ballast water from tankers and the berth loading arms.

Another former Alyeska manager, Darcy Hammond, will help with the maintenance audit. Hisey said Hammond, who retired from Alyeska in December 2010, spent years working with RCM on the pipeline.

Hisey said he’s hopeful the maintenance audit will be useful not only for the RCAC, but for Alyeska as well.

The final audit report is expected by June 30.

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Marks: Progressivity dysfunctional

Petroleum economist, contracting for LB&A, tells legislators Alaska not competitive for investment with comparable oil provinces

By KRISTEN NIELSON

Petroleum economist Roger Marks, under contract to the Alaska Legislature’s Budget and Audit Committee, told the House Finance Committee March 15 that he believes the progressivity structure within ACES is dysfunctional. He said this has concerned him since progressivity was enacted as part of the Petroleum Production Tax in 2006. ACES, Alaska’s Clear and Equitable Share, enacted in 2007, made progressivity more aggressive, Marks said.

Marks was testifying on House Bill 110, Gov. Sean Parnell’s proposal to reduce oil and gas taxes by changing how progressivity is applied, capping it and establishing a lower base rate for new fields.

There’s nothing wrong with the principle of progressivity, Marks said — you pay less tax when you have less income and more tax when you have more income. But progressivity in Alaska’s tax system is not like the bracketed system in the U.S. tax code for individual taxpayers, where higher tax levels only apply to incremental amounts of income. With ACES, when progressivity kicks in at net profits above $30 a barrel on crude oil, the highest rate is applied to every dollar of value.

This is reflected in the marginal tax rate, he said: at $90 a barrel the marginal tax rate is 80 percent, so producers get only 20 cents of the marginal dollar from 89 to 90.

Because of the high marginal tax rate, Marks said, producers don’t make that much money as prices go up. That’s a problem because when producers evaluate projects they look to the high side and with that high side suppressed in ACES, a project might not happen.

Alaska v. other jurisdictions

Marks compared Alaska to a group of jurisdictions based on comparable tax and royalty regimes (as opposed to jurisdictions with production sharing regimes) and comparable resources. Except for Alaska, he said, none of these have progressivity. And at $100 a barrel, Alaska’s rate is the highest except for Norway, where most of the equity production is owned by Statoil.

As for fixing ACES, Marks told legislators he doesn’t believe you can fix ACES with more credits: Tax dwarfs credits, he said.

EXPLORATION & PRODUCTION

Doyon plans new Nenana seismic survey

As part of a continuing search for oil and natural gas in the Nenana basin, in Interior Alaska, about 50 miles southwest of Fairbanks, Doyon Ltd. is planning to carry out a 2-D seismic survey in the northern part of the basin during the winter of 2012, the Alaska Native regional corporation said March 16. Doyon will primarily conduct the survey on state land within the area of a state exploration license that Doyon holds. However, some Doyon-owned land and some land owned by Toghotthele Corp., the village corporation for the Nenana village, may be involved in the survey, Doyon said.

A partnership consisting of Doyon, Rampart Energy Co., Arctic Slope Regional Corp., Usibelli Energy LLC and Cedar Creek Oil & Gas Co. has been conducting an exploration program in the Nenana basin and in 2009 drilled the 11,000-foot Numivaq No. 1 well near Nenana. Doyon says that, although that well demonstrated the existence of an active petroleum system in the basin, the well did not encounter an economic accumulation of natural gas.

Doyon says that it has taken over from Rampart as operator of the Nenana exploration program and that, so far, Doyon is the only member of the partnership to commit to the new seismic survey. The regional corporation says that it is prepared to proceed with the survey without the participation of some or all or the other members of the partnership.

James Merry, Doyon senior vice president, lands and natural resources, told Petroleum News March 16 that the northern part of the basin, where the new survey will take place, is the deepest and broadest part of the basin. Analogous freshwater basins elsewhere in the world tend to have some of their most prolific petroleum plays in the basin centers, Merry said.

Doyon has licensed and re-interpreted some gravity and magnetic data for the basin, but there is no existing seismic data for the northern part of the basin, he said.

—ALAN BAILEY

Learn more. View Responsible Development, a video showcasing BBNC’s land and resource vision at www.bbncc.net.
than 500,000 acres in the State of Alaska’s annual North Slope lease sale, is about to change."

As for Eagle Ford being the hottest shale oil play, he says, “We believe that Eagle Ford shale formation in South Texas, Alaska North Slope resembles the hot rocks resemble some of the hottest shale plays in North America because natural fracturing can make recovery possible. So there are usually an “oil window” and orange weathering is characteristic of lushous intervals in this succession. Stratigraphic younging direction is to the right. View to west.

Duncan: Our timing was fortuitous

Great Bear carefully selected shale oil acreage won in 2010 North Slope areawide lease sale prize was three of richest source rocks in world

By KAY CASHMAN
Petroleum News

According to Great Bear Petroleum’s top executive, Alaska has three of the most prolific, world class, source rocks in the world. Individually, Ed Duncan says, “as source rocks, they are superior to the Eagle Ford shale play in Texas, currently considered the hottest conventional oil play in the world.” As for Eagle Ford being the hottest shale oil play, he says, “We believe that is about to change.”

Great Bear entered Alaska in October by placing winning bids on more than 500,000 acres in the State of Alaska’s annual North Slope lease sale, see GREAT BEAR TIMING page 18

Why Alaska sees hope in source rocks

State petroleum geologist tells lawmakers that North Slope source rocks resemble some of the hottest shale plays in North America

by ERIC LIDJI
For Petroleum News

The State of Alaska is “cautiously optimistic” about oil development from source rocks.

“Optimistic” because the geology of the Alaska North Slope resembles the hot Eagle Ford shale formation in South Texas, and Great Bear Petroleum’s leases are “well positioned” to develop that geology, a Division of Oil and Gas petroleum geologist recently told state lawmakers.

“Cautiously” because developing source rocks is an entirely new concept in Alaska that will require a lot of equipment, crews and water, and some trial and error.

“If these production pilots and exploration success do occur then full-scale development, if it were to occur, could be quite a whirlwind,” Paul Decker said on Feb. 23. “But, you know, things remain to be seen. But at this point I think we’re cautiously optimistic.”

The play Great Bear is proposing to develop at its new 537,500-acre North Slope lease position is so new for Alaska that it doesn’t even have an agreed upon name, but Decker is calling it “source-reservoir oil,” meaning that the source rock is also the reservoir, because the rocks are so tight that they hold onto the oil they generate like a traditional geologic trap.

What makes for good rocks?

The North Slope is home to three “productive” source rock intervals that are candidates for development: the Shublik, the Kingak and the GRZ/Hue shale system, from deepest to shallowest. These source rocks exist some 8,000 to 13,000 feet underground.

The factors that make source rocks good candidates for development include the organic chemistry — the ingredients for making oil, elements like carbon and hydrogen — and the thermal maturity — the underground heat needed to turn those elements into oil.

For source rocks to become the “kitchen” where oil and gas gets “cooked,” they must be deep enough for the heat of the earth to reach the proper temperatures. Shallow rocks are too cool, or “immature,” and won’t generate oil and gas for ages, but in the hotter depths below those immature rocks are usually an “oil window” and a deeper “gas window.”

The tectonic history is also important, because natural fracturing can make recovery easier and needs to be well understood in order to design, drill, and complete the
Oil makes a grab for shale crown

Lower 48 shale game started out as gas play, but low gas prices, new technology have firms chasing higher value oil, natural gas liquids

By ERIC UDOR
For Petroleum News

The potential for a shale oil boom on the North Slope of Alaska is based on slightly different market factors than the current rush on similar formations across the Lower 48.

The interest in oil-bearing source rocks on the North Slope is based in part of infrastructure. The lack of a natural gas pipeline makes oil the only sure bet in northern Alaska, while declining throughput on the trans-Alaska oil pipeline is creating an incentive — and a public need — for producers to find new volumes of oil.

In the Lower 48, though, recent interest in shale oil is about prices. When shale gas exploration exploded in 2008, oil topped $150 a barrel and natural gas topped $13 per thousand cubic feet, but today oil is $100 a barrel and natural gas is less than $4 per mcf.

Oil has always been more valuable than gas, but technological constraints kept companies from pursuing it until Petrohawk cracked the code in the Eagle Ford in 2008.

The recent shift became clear as companies released their annual reports this year.

Chesapeake Energy, which calls itself “America’s Champion of Natural Gas,” doubled its oil production in 2010 and said it didn’t plan to transition away from oil even if natural gas prices improve in the next few years. “We can drill a natural gas well and receive around $4 per unit of production or we can drill an oil well and receive around $15 per unit of production,” CEO Aubrey McClendon told investors in late February.

Range Resources recently sold its Barnett Shale properties in North Texas to focus on Appalachia, where three stacked shale plays — the Marcellus, Upper Devonian and Utica — create economies of scale by offering liquids-rich shale gas formations.

After watching gas volumes drop except at liquids-rich plays like the Granite Wash tight sands in Oklahoma, MarkWest Energy Partners, a midstream company, wants to connect liquids operations from Pennsylvania through Kentucky and down to Gulf Coast markets.

The major service companies see the writing on the wall, too. “With natural gas price forecasts from the Energy Information Agency for 2011 slipping by nearly a third compared to initial projections made at the beginning of the year, an increasing portion of the drilling and completion activity in shale reservoirs has shifted to liquid and condensate-rich plays in North America,” Schlumberger wrote in a year-end filing.

Baker Hughes noted that recent spending on shale gas is based on temporary market oddities: hedging leftover from times of higher prices, the need to drill wells to meet lease terms, joint venture capital coming from overseas companies looking to gain technical know-how and experience and boosts from associated liquids production.

Cracking the nut

To tap natural gas trapped in underground source rock (mostly shale) where hydrocarbons are trapped (only a small percentage ever escapes), producers drill down and horizontally into the tight rock, then pump water, sand and chemicals into the hole to crack the shale and allow natural gas to flow up.

Because oil molecules are sticky and larger than gas molecules, engineers thought the process wouldn’t work to squeeze oil out fast enough to make it economical. But drillers learned how to increase the number of cracks in the rock and use different chemicals to free up oil at low cost.

“We’ve completely transformed the natural gas industry, and I wouldn’t be surprised if we transform the oil business in the next few years too,” McClendon said.

Petroleum engineers first used the method to unlock oil from source rock in 2007 from the Bakken Shale, a 25,000-square-mile formation under North Dakota and Montana.

A huge increase in interest followed a 2008 U.S. Geologic Survey study suggesting that the Bakken contained 3 billion to 4.3 billion barrels of oil, a 25-fold increase over the previous USGS estimate, made in 1995.

That increase is the result of one word: recoverable. Improvements in technology between 1995 and 2008 made it possible for companies to first extract natural gas and then, in 2007, begin to extract liquids.

On to the Eagle Ford shale

Once the odd-man-out as an oily shale play, the Bakken is now a trailblazer. Producers are increasingly focused on the oil and natural gas liquids potential of shale gas plays.


In just this past year liquids production in the Bakken rose 50 percent to 458,000 barrels a day, according to Bentek Energy, an energy analysis firm.

In the Eagle Ford shale of South Texas, oil production jumped from 300,000 barrels in 2008 to nearly 2.6 million barrels in 2010 and condensate production jumped from some 500,000 barrels in 2009 to nearly 3.3 million barrels in 2010, according to the Railroad Commission of Texas, the main permitting and statistical agency in the state.

Those increases dwarf the not-to-shabby four-fold jump in natural gas production last year.

see SHALE CROWN page 11

CASE STUDY: Bakken Shale

Huge Positive Impact on North Dakota Economy

- Largest “continuous” oil accumulation ever assessed by USGS with estimated mean recoverable oil reserves: 3.7 bn bbls
- Potential huge upside in a second oil-rich shale reserve (Three Forks) that lies below Bakken Shale
- North Dakota has since surpassed Louisiana as 4th largest oil-producing state in U.S.
- A recent North Dakota University study identified substantial positive impact from oil & gas development
  - Nearly 13,000 new jobs created between 2005–2009
  - Direct economic impact grew from US$1.3bn in 2005 to US$4.6bn in 2009
  - No. of active wells rose from 3,987 in 2005 to 6,190 in 2009
  - Each new well has an estimated US$3mn annual impact and creates 47 new jobs
  - Lowest unemployment rate in the nation (3.6%)
  - Forecast budget surplus of US$7bn in June 2011
  - State estimated to collect over US$2bn in oil taxes during the next budget period (Jul 2011-Jun 2013)
Great Bear scored, but didn’t win it all

Although Great Bear well-positioned, Duncan and Decker say there’s plenty of room for other players in North Slope shale plays

By KAY CASHMAN
Petroleum News

W ill there be room for other companies to develop shale plays on Alaska’s North Slope or did Great Bear Bear Petroleum win most of the acreage in the oil maturation window?

“By no means did Great Bear win all of the acreage that would be prospective, that would appear to be in the oil maturation window,” Alaska Division of Oil and Gas geologist Paul Decker told Petroleum News.

“I think they are very well-positioned geologically,” he said, referring to the 500,000 acres plus the newly formed independent was high bidder on in the October State of Alaska North Slope oil and gas lease sale. (See maps on page 19.)

But it’s “a question of geology versus ‘close-ology,’” Decker said. “Based on thermal maturity, the North Slope source rock plays likely extend far beyond Great Bear’s acreage position, particularly to the west. However, from the perspective of needing to build out year-round access and infrastructure tie-backs, someplace very close to the Dalton Highway, TAPS, and infrastructure tie-backs, someplace...
Brooks Range joins Alaska shale game

Local independent has 100,000 acres-plus under lease on North Slope in maturation window of two or three world class source rocks

By KAY CASHMAN
Petroleum News

An Alaska-based joint venture that is drilling the state’s only exploration well on the North Slope this winter says it has more than 100,000 acres under lease west of the Kuparuk oil field in the maturation window of two, possibly three, world class source rocks — the Shublik, Kingak and possibly the HRZ shales.

Ken Thompson, managing director of Alaska Venture Capital Group, or AVCG, conversed via e-mail with Petroleum News in mid-March about the company’s plans to find a partner with capital and expertise in Lower 48 shale plays.

In 2006, AVCG formed the joint venture and formed Brooks Range Petroleum Corp., or BRPC, the Alaska operating entity for the working interest owners, who are currently Kansas-based AVCG, which holds a 50 percent working interest in the JV’s 240,000 acres on the North Slope and nearshore Beaufort Sea; TG World Energy, a small Calgary public corporation; and Ramshorn Investments, a wholly owned subsidiary of Nabors Drilling USA, out of Houston.

The new partner will replace Calgary-based Bow Valley Energy Ltd.

“About a year ago or so, we had a company that was a great partner of ours out of Calgary called Bow Valley,” Thompson told Alaska lawmakers in February. “Bow Valley was a small public company. It was acquired by another larger public company in the UK, out of England, called Dana Petroleum.”

Dana Petroleum came to “the conclusion that the fiscal regime in Alaska was tougher than the UK … and so they decided to focus solely on the UK and told us they did not want to invest in Alaska, so we acquired their interest (about 20 percent), running our interest from 30 percent up to the current 50 percent,” Thompson said.

Looking for a partner with shale oil expertise

“My job in the last … nine months has been to pound the pavement, make a lot of contacts and get our … next investor … that can bring capital, as well as expertise, to us.”

In the same period of time the partners were assessing their acreage for source rock potential, Thompson told lawmakers.

“Starting with our working interest owners’ meeting in Anchorage on July 20, 2010, we discussed the source rock potential and began some of our geologic assessment on AVCG et al acreage and surrounding areas. We feel our JV’s almost 100,000 acres to the west around Tofkat, Big Island and even our Southern Miluveach unit area has source rock potential being in the right maturation and depth window. And we are also studying source rock and low-permeability
sands potential in our Beechey Point unit,” Thompson told Petroleum News March 11, when asked to elaborate on what he and Bart Arntfield, vice president of operations for BRPC, told lawmakers Feb. 18 at a House Resources Committee meeting.

Thompson also explained why A VCG and its JV partners did not go after additional acreage with shale oil potential at the State of Alaska’s annual North Slope area-wide lease sale in October, which was when Great Bear Petroleum entered the state, the highest bidder on more than 500,000 acres.

A VCG and its partners thought they had enough acreage, Thompson said. “To get started in our assessment and possible future development, we thought our JV’s almost 100,000 acres out west and overall almost 250,000 acre spread across the North Slope was enough for our JV budget, so we did not bid aggressively at the last October lease sale.”

He also said the JV partners “have made great progress on a comprehensive well log assessment and we plan visual core studies in 2011. Could these source rock shales and/or lower-permeability sands in these areas on the North Slope be the next Bakken or the next Eagle Ford development? A VCG and our JV partners plan to find out!”

**JV’s focus on next frontiers**

Thompson said A VCG and its partners focus “is on what we call the next frontiers for major developments on the North Slope,” which “fall into two categories for what we do.”

One, he said, is exploration for smaller fields. Smaller being “in the 25-to-50 million barrel range,” noting it was possible they would find something larger, “but for now we’re focused on those.

Both in his days with ARCO and more recently with A VCG, looking at seismic, he “saw a lot of” 25-50 million barrel fields. (Thompson was president of ARCO Alaska before its last president, Kevin O. Meyers; then chairman and CEO of ARCO Alaska and one of four top executive vice presidents at corporate before the company’s Alaska assets were sold to Phillips Petroleum and the main company acquired by BP)

“We believe there’s a lot of potential production in low-permeability sands; there are a couple of resources, they’re more expensive to develop, but on our Southern Miliravech unit to the west ... we have identified about 1 billion barrels in place, maybe about only 20 percent of that’s recoverable, but it’s ... more expensive to develop.”

The second frontier for major developments that his company and its partners are “excited about” is the “oil-source shales,” believing the JV’s acreage holds “significant potential” for shale plays.

Other sources of oil on and offshore the North Slope are better suited for the majors, Thompson said, referring to heavy oil extraction and exploration and development in the federal waters of the outer continental shelf of the Beaufort and Chukchi seas.

The BRPC partners talked about the potential of their source rock acreage with more than 75 companies in their booth at the North American Prospect Expo, or NAPIE, in February. They were there, Thompson said, “specifically to find a partner to join our JV with the skills, experience and technology in source rock shales as well as completions and stimulations technologies for low-permeability sands.”

Company officials also touted “a number of conventional leads and prospects,” he said.

**Six companies want more information**

Six companies, he said, “have asked BRPC to send them more information and to possibly schedule technical sessions to further review our conventional leads and prospects and the source rock potential”;

Two more international majors, two large U.S. independents and two small/medium-sized U.S. independents.

“Two more companies — a large independent and small independent — said they may be interested after visiting with their senior management further, and will let us know. Incidentally, all six of the companies that told us at the booth they wanted more information, expressed interest in the unconventional resources monitoring showing our acreage being in the good maturation windows of the Shubik, Knigak, Pebble Shale and HRZ shale intervals,” Thompson said. (See montage attached to this article.)

**And then there was the tax issue**

A key thing the JV partners manning the NAPIE booth heard from “most of the companies that stopped by, including those who want to follow up with us,” was that “they would not have stopped — they would have kept on walking by our booth — were it not for reports in the oil industry press about Gov. Parnell’s bill to change Alaska’s ACES (production) tax structure to be more reasonable.”

“In particular,” Thompson said in an e-mail to Petroleum News, “they liked the capital tax credits for development and lower tax rate and lower cap for new fields. We also let the companies know we were hoping for the credits to be reim-bursed in a year instead of over two years, which helps independents quickly plow the capital back into seismic and drilling.

Extension of the ‘small producer tax credit’ from May 2016 to May 2021 also attracted interest as a positive for investment.

“Quite honestly, if the Legislature makes progress in March adopting the positive changes to ACES, I believe we’ll find the partner we’re hoping for with capital and technology. If ACES’ changes do not occur, I’m not as positive. Somehow, the State needs to adopt one common goal and technology. If ACES’ changes do not occur, I’m not as positive. Somehow, the State needs to adopt one common goal with industry: ‘NO DECLINE.’”

“I believe the conventional prospects left on the North Slope, the huge viscous oil base, the large potential in low-permeability sands, and the source rock potential all could add up to a leveling of oil production for the state. Instead of fighting over a fixed pie of revenues, the State of Alaska and industry could each enjoy a fair share of a much bigger pie of revenues,” Thompson said.

**Regional, shared processing facilities**

In his presentation to Alaska lawmakers, Thompson also brought up the “con- cept of regional processing facilities that we would like to construct that would allow smaller fields — no matter who operates them — to bring ... (their production) into our regional facilities. Now that could be helpful, too, to stopping, leveling the decline.”

With the exception of Eni’s new Nikaitchaq oil field, all producing fields in northern Alaska are operated by two companies: BP and ConocoPhillips. Although oil production is down, most of the legacy fields are close to, or at, capacity for water and/or natural gas handling, which means the owners of those facilities have to back out their own oil to make room for third party oil.

According to the U.S. Department of Energy’s Energy Information Administration forecasts, the U.S. will still depend on oil and natural gas for 60-65% of its domestic energy consumption in 2025.

The U.S. is currently importing 56-58% of its oil, much of it from regions of questionable stability and regimes not always friendly to our country.

Prudhoe Bay was initially estimated to hold 9.6 billion barrels of oil. So far, Prudhoe Bay has produced over 15.9 billion barrels of oil. Alaska continues to be the new frontier for oil and gas production.

**Alaska has the resources. Alaska has the experience.**

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———

**Contact Kay Cashman at publisher@petroleumnews.com**
Stable flow channels mean increased production

Encana used the HiWAY* flow-channel hydraulic fracturing technique to improve productivity in the Jonah field near Pinedale, Wyoming. The results:
- 24% more gas production than an offset well
- 14% more production than the campaign’s expected best producer (which had 40% more net pay) after 180 days.

HiWAY hydraulic fracturing technique creates flow channels to maximize the deliverability of the reservoir. There’s nothing between the reservoir and the well, so reservoir pressure alone determines flow.

www.slb.com/HiWAY

“Tough, but not impossible,” says Nabor

Petroleum News asked Dave Hebert at Nabors Alaska Drilling if Nabors could deliver 20 new rigs in 12 months because Great Bear is hoping to sanction development by 2013. Three years ago Nabors delivered the first purpose-built AC rigs for the North Slope in 13 months, from design to delivery. Two years ago the company delivered CDR-2 to ConocoPhillips at Kapusk; it was the first purpose-built coiled tubing rig designed for the Arctic. It took 18 months, from design to delivery.

Hebert said it would be “tough, but not impossible,” to provide a one-year turnaround on rigs for Great Bear.

“A lot would depend on the rig design, and if all 20 rigs were essentially the same. We certainly have a lot of options for rig construction at our disposal,” he says. See NEW Rigs page 15.
Cook Inlet companies eye unconventional

By KAY CASHMAN
Petroleum News

While most of the focus in Alaska is on shale oil plays on the North Slope, at least two oil and gas companies in the Cook Inlet basin are looking at checking out the source rock, or shale, in their acreage — Aurora Gas and Escopeta Oil.

As this section in Petroleum News went into production on March 17 morning (see page 1 article for latest news), Escopeta had loaded the Spartan 151 jack-up rig onto a heavy lift vessel at a dock in Freeport, Texas, and was expecting to set sail for Alaska late that afternoon or the next morning.

Escopeta President Danny Davis told Petroleum News that he intends to check out the source rock in his Kitchen Lights unit wells, while looking for conventional oil and gas targets.

“We’re going to take a look at the source rock as best as we can with the jack-up,” Davis said. If it looks promising for an unconventional resource play, which is what Great Bear Petroleum is chasing on the North Slope, Escopeta is going to further check it out once it gets a production platform in place.

And at an Anchorage Chamber of Commerce meeting on Feb. 7, Aurora Gas President Scott Pföff said that last summer Aurora successfully tried using hydraulic fracturing in a well in its Three Mile Creek field. The technique, similar to the “fracking” done in Lower 48 shale gas wells, was applied to the field reservoir in a conventional gas well, with the effect of boosting gas production, Pföff later told Petroleum News. Aurora hopes to use the same technology in other wells and is also interested in the potential to use modern fracking techniques in other Cook Inlet situations, such as in tight gas sands or perhaps in gas source rocks, Pföff said.

Aurora has for some time been interested in the potential to develop coalbed methane in and around its leases, especially given that those leases are in remote locations, near the pipeline infrastructure but far from population centers.

Pföff said the company estimates there is a coalbed methane resource equivalent to at least a 10-year gas supply for Southcentral Alaska just in the areas around Aurora’s leases.

“The resource potential is huge,” he said, also commenting that any development would need to be carried out in a way that avoids the pitfalls encountered in the past with Alaska coalbed methane proposals.

Contact Kay Cashman at publisher@petroleumnews.com
USGS assessing unconventional resources

Agency is investigating the Alaska potential for developing unconventional plays such as shale oil, shale gas and coalbed methane

BY ALAN BAILEY

While much oil and gas interest in North America has focused recently on new so-called unconventional oil and gas plays, especially involving the extraction of hydrocarbon resources directly from oil and gas shales, the Alaska oil industry has continued along a route of seeking and developing oil from conventional porous and permeable reservoir rocks.

But with Great Bear Petroleum forging ahead with plans to extract oil directly from source rocks on the North Slope, Alaska looks set to join the unconventional oil and gas bandwagon.

And the U.S. Geological Survey, the federal agency that has for many years conducted assessments of Alaska’s conventional onshore oil and gas resources, is now turning its attention to estimating how much unconventional oil and gas might be accessible in northern Alaska and in the Cook Inlet basin.

The agency hopes to complete its Cook Inlet assessment sometime in the fall, USGS geologist Dave Houseknecht told Petroleum News Feb. 8.

Trapped in the rock

Unlike a conventional oil and gas play, where hydrocarbons migrate into a porous source rock to become trapped under an impervious seal rock, an unconventional play, sometimes referred to as a “continuous” play, involves a rock unit saturated with oil or gas over a broad area, with the fabric of the rock itself, rather than an overlying seal rock, trapping the hydrocarbons in place.

The much publicized “fracking” techniques used in this type of play release the hydrocarbons by smashing open the rock fabric.

Estimating the producible volumes of hydrocarbon resources in this type of unconventional play involves assessing three factors: the extent and thickness of the hydrocarbon bearing rock unit, the mechanical and oil production properties of the rock; and the likely success rates for well production from the rock.

Houseknecht explained. Essentially, a geologist conducting the assessment will use the rock properties to estimate the sizes of cells from which individual wells might be able to drain hydrocarbons and will use the hydrocarbon production characteristics of the rock to estimate ultimate production volumes for the wells.

The geologist will then statistically combine possible ranges of cell sizes and likely production volume ranges, together with ranges in the estimated extent of the complete rock unit, to derive a range of potential, extractable hydrocarbons in the play as a whole.

USGS conducted an assessment of North Slope coalbed methane resources in 2006. And, although there are likely to be substantial unconventional North Slope resources in impermeable, “tight” sands, USGS needs access to appropriate 3-D seismic data to delineate the tight sand bodies, Houseknecht said.

There are probably resources in tight sands, even within existing North Slope oil and gas productions units, but individual sand bodies are probably limited in extent, he said.

Focus on source rock

So, the agency is focusing on potential oil and gas production direct from source rocks, starting with the Cretaceous Gamma Ray Zone and Hue shale, and the Triassic Shublik formation, two prominent source rock intervals that have generated much oil in the North Slope oil fields.

But, given the total lack of any track record of unconventional oil and gas production on the North Slope, estimating the rock’s production characteristics, the parameters needed to estimate the well drainage cell sizes and well productivity, is one of the biggest challenges in conducting an unconventional resource assessment in Alaska, Houseknecht said.

Essentially, the geologists have to find analogous rocks from the Lower 48, rocks that have been used for unconventional production and that appear to have some what similar characteristics to those on the North Slope, in order to infer the required North Slope production characteristics.

Quite a bit is, however, already known about one key rock property: the distribution of thermal maturity, the measure of the extent to which the rock has been heated to generate oil or natural gas. In general, for example, the thermal maturity is relatively low on the crest of the Barrow arch, a major geologic structure along the Beaufort Sea coast, but increases to the south.

Gamma ray response

For the Cretaceous sources USGS is using the gamma ray response, a hydrocarbon content indicator, from existing well logs to infer hydrocarbon-rich rock depths and thicknesses at different locations, Houseknecht said. And the good news is that the thickest high-gamma-ray concentrations occur along a trend of thermal maturity appropriate for oil generation, he said.

However, a prevalence of carbonate minerals has distorted the gamma ray responses in the Shublik, causing the USGS geologists to resort to a more complex procedure to locate the likely sweet spots in the Shublik source — using data from the Phoenix well, offshore north of the Columbia River Delta, USGS is correlating the thickness of the likely prime hydrocarbon-bearing zone of the Shublik across multiple wells.

And there is evidence from existing well penetrations on the North Slope that the Shublik is fractured and is brittle enough for fracture stimulation.

see USGS ASSESSMENT page 17
On the Web
See previous Petroleum News coverage:


“Independents: There are ways to stem declining oil flow in line” in Feb. 27, 2011 issue at http://www.petroleumnews.com/pnads/81724688.shtml


continued from page 16

USGS ASSESSMENT
Houseknecht said.

There’s encouragement but quite a bit of uncertainty, he said.

Cook Inlet basin
In the Cook Inlet basin, USGS has already committed to an assessment of conventional resources but is now also assessing coalbed methane resources and potential gas production from impermeable or “tight” gas sands. Direct gas production from source rocks, in particular from rocks in the Jurassic Tuxedni group, the main oil source for the Cook Inlet oil fields, is also a possibility, although the paucity of well penetrations into this deeply buried rock unit make it impossible at present to make a quantitative assessment of this play, Houseknecht said.

With massive quantities of Cook Inlet basin coal, much of it in the form of pod-like accumulations rather than continuous coal seams, the potential for coalbed methane production particularly intrigues the USGS geologists and is a significant focus of the Cook Inlet assessment. As with the northern Alaska source rocks, the lack of any production track record in the region drives the need to seek analogous coals elsewhere in order to infer Cook Inlet coal production characteristics. But USGS has a substantial database of coalbed methane production data from North America and the gas production characteristics of many coals tend to be somewhat similar, Houseknecht said.

The USGS geologists have plotted zones where Cook Inlet well data indicate an abundance of thick coal seams, to identify the likely “sweet spots” for coalbed methane production. A large area of territory down the west side of the Cook Inlet seems especially promising.●

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The Eagle Ford shale represents the best analogue to Great Bear’s North Alaskan opportunity. Great Bear has not one shale opportunity, but three, all of which are superior to the Eagle Ford.

<table>
<thead>
<tr>
<th>Key Technique/Comps</th>
<th>Shublik</th>
<th>Kiguk</th>
<th>Hue</th>
<th>Eagle Ford</th>
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<td>North Alaska</td>
<td>South Texas</td>
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<td>2,500-3,000</td>
<td>2,000-2,500</td>
<td>3,000-4,500</td>
</tr>
</tbody>
</table>

Terms:
- *Calculated from average TOC by measurements
- TOC= Total Organic Carbon
- Vitrinite Reflectance (% R) is a measure of thermal maturity

At the moment the Eagle Ford is the "hottest unconventional oil shale play in the world.” We believe that is about to change.


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GREAT BEAR TIMING

acres Duncan says contains a chunk of the geologic “kitchen” that generated the 100 billion barrels of oil that millions of years ago migrated north into traps along northern Alaska’s coast. Those traps include the giant reservoirs of Prudhoe Bay, the largest producing oil field in North America, and Kuparuk, the second largest onshore oil field.

If production begins in 2013 as planned, in a conservatively scaled project of 200 wells a year, Great Bear says production from its acreage alone at 200,000 barrels per day by 2020: 350,000 bpd by 2035; 450,000 bpd by 2041; peaking at 600,000 bpd in 2056, with a sustained long-term production of 450,000 barrels per day out as far as 2074.

Decker said it appeared Great Bear had “very carefully selected” its acreage position. “They are pretty well positioned, I would say, to pick up the appropriate thermal mature zone for the Triassic and lower Jurassic Kiguk.” The same, he said, was true for the youngest and shallowest source rock, the Cretaceous-age Hue shale, also called the GRZ, HRZ and Pebble shale.

That’s from exploiting just two of three stacked shale plays in a measured drillout program of 45 years. When Alaska lawmakers recently asked him if Great Bear could bump the number of wells up to 1,000 a year in order to get a million barrels of oil into the trans-Alaska oil pipeline, Duncan said yes, if he had the support of all the stakeholders in such an accelerated program.

So, why is Duncan certain that his company’s acreage holds billions of barrels of recoverable oil?

A careful, informed selection; not a land grab

The geology of the North Slope is well known and understood, documented by seismic, numerous field studies and well data, Duncan said. So when his company bid on 537,600 acres in last year’s North Slope lease sale, it was not making a “blind land grab,” a statement confirmed by one of the State of Alaska’s leading geologists, Paul Decker, in February testimony before the Alaska Senate Resources Committee, and in an interview with Petroleum News.

Decker said it appeared Great Bear had “very carefully selected” its acreage position.

“They are pretty well positioned, I would say, to pick up the appropriate thermal mature zone for the Triassic and lower Jurassic Kiguk.”

The same, he said, was true for the youngest and shallowest source rock, the Cretaceous-age Hue shale, also called the GRZ, HRZ and Pebble shale: “Great Bear again is well positioned… for this zone as well.”

Indeed, the use of a major basin model that traced the source of the oil in the giant Prudhoe Bay field, and others, was of great help to Duncan.

The report was created by the U.S. Geological Survey. Ken Peters, a former USGS geochemist who worked closely with USGS geologist Ken Bird to create
SOURCE ROCKS

wells most effectively.

Clues in Texas and N. Dakota

Trying to analyze the source rocks on the North Slope, the most comparable basins are the Eagle Ford shale in Texas and the Bakken shale in North Dakota. On average, North Slope source rocks aren’t as organically rich as the Bakken or the best parts of the Eagle Ford, but they are generally thicker. The Shublik rocks appear to be brittle like the Eagle Ford and the Bakken, but typical Shublik-sourced oil is somewhat heavier. The Kingak and GRZ/Hue appear to be less brittle than the Eagle Ford and Bakken, but are known to generate somewhat lighter oil than the Shublik.

“We expect that the Eagle Ford is going to be a pretty good place to look to answer questions that we don’t yet know from direct evidence from our own source rock,” Decker said.

Does that mean Alaska is as prolific as the Eagle Ford or the Bakken?

Decker said it’s still too soon to say, but noted that a U.S. Geological Survey assessment of the unconventional oil and gas resources in Arctic Alaska slated for release next year should shed some light on just how much oil is down there.

“We are very encouraged from what we know right now, but the proof is in the drilling,” Decker said.

Currently, only Great Bear Petroleum is looking to explore source rocks, but if it can successfully develop the resource it would likely create a rush on the North Slope. Great Bear President and COO Ed Duncan told lawmakers that he believes his leases alone could contain some 2 billion barrels of oil and 12 trillion cubic feet of natural gas.

The learning curve ahead

With unconventional oil plays, though, the trick is recovery.

Unlike a conventional reservoir, there are no “dry holes” in source rocks because the rocks are saturated with oil or gas. The question is whether the oil can be recovered.

Decker said success on the North Slope would depend on gathering enough good data about the source rocks to support a pilot project. “We are going to need to get that learning curve and lower the cost of drilling wells. It is partly learning. It’s partly just getting enough equipment up there I think. But we need to lower those costs,” he said.

A pilot project would help craft an Alaska model for development. Drillers in the Bakken Shale typically drill from five-acre pads spaced every 640 acres. From each pad, one horizontal or multilateral well extends up to two miles in length. Spacing is much tighter in the Eagle Ford, between 125 and 140 acres per well, and would likely be tighter in Alaska, as well, with multiple horizontal wells drilled from each pad. Great Bear plans to use one-acre pads every 120 to 160 acres.

Because source rocks don’t yield their resources like conventional resources, drillers must fracture and stimulate the rocks with large amounts of water and sand. Production rates usually decline quickly over the first two years, but decline more slowly over the next decade or more.

Decker said Alaska needs more equipment, more crews, a sufficient water supply, transparent fracturing practices to guarantee that permafrost and drinking water supplies are adequately protected and new all-seasons roads to allow for year-round surface access.
continued from page 18

GREAT BEAR TIMING

the model.

“The model illustrated the oil in reservoirs along the Barrow Arch, including Prudhoe and Kuparuk was generated 75 to 78 percent in the Shublik and Kingak, and the balance was from sources HRZ and Hue shales,” Duncan said.

“Based on their model, and on a lot of our work over the year (preceding the October lease sale), the kitchen area where the source rock is mature … is the area we have leased …”

“… There are massive amounts of very, very good technical information and studies on this basin. I kept reviewing everything, looking for critical problems, talking to the best geoscientists that I knew of … We knew where the source rocks were, we knew their thermal maturity. I went over all of it several times alone and with colleagues,” Duncan said.

“I am quietly confident … had we not made our move in this lease sale we would have been locked out of it by next. Our timing was fortuitous,” Duncan said, echoing the sentiments of the early leaseholders in the Bakken, Eagle Ford and other shale plays in the Lower 48.

Matching geology with technology for BP

Considering the job Duncan did for Sohio (now BP) in Alaska, from 1982 to the late 1980s, it’s not surprising that Great Bear was first to pick up leases targeting an oil shale play in Alaska’s Brookian Foredeep, also known as the Colville basin, which lies north of the Brooks Range.

A project supervisor and geologist with the Sohio exploration group, Duncan was in charge of everything on and offshore between the Colville River and the Canadian border, tasked with matching the geology of an area or prospect with advances in technology that might make it economically viable.

Not only was he well versed in the North Slope’s petroleum systems, but he was trained to watch for the convergence of technology and geology, which he saw initially with Petrohawk Energy’s advances in well design at Eagle Ford, involving everything from increased lateral lengths to less restrictive choke sizes, tighter perforation cluster spacing, increased proppant and the use of new vegetable based fracking gels to overcome concerns about the use of toxic chemicals in hydraulic fracking operations.

Geology, technology surmountable challenges

Duncan asserts the challenge of producing oil and gas from North Slope source rocks in Great Bear’s leases has little to do with the area’s geology.

“The challenge is not the geology; it’s well understood here. The challenge for the play is: Is it operationally doable on the slope,” he said in a recent interview with Petroleum News.

The answer, Duncan said, is yes.

“We got past that issue pretty quickly,” he said.

“There’s always a chance the rocks just won’t perform the way we want them to. We don’t expect that. That’s way outside our prediction range of outcomes. Also, there’s a chance the rocks will perform well beyond what we might imagine from an analog perspective,” Duncan said.

“We maintain the technology and the geology are a perfect match — or will be as soon as his associates have tweaked their well design.

“We have some technical uncertainties to address — that’s one of the reasons we want to do our core holes soon,” Duncan said, referring to the holes Great Bear has tentatively scheduled for late fall.

“We need to design our fracs. Our first four planned full production test wells have large R&D research element in them. We’ll perfect a method very quickly in the first few wells, then we go into factory drilling, and the costs go down at that point.

“That’s the operational model that has been developed in the Lower 48,” he said, explaining that he expects the wells to be roughly 9,000 to 11,000 feet deep with 4,000 to 6,000 foot laterals.

“We’ll drill down to the source rock and then run the laterals along the source rock strata and using state-of-the-art rock fracturing techniques to cause oil to flow direct from the source,” Duncan said in the interview, repeating much of the same to legislators in his Feb. 26 presentation.

The Shublik, then the Shublik again

In phases one and two, Great Bear will target the deepest and oldest of the three source rocks, the Triassic-age Shublik formation. In the process the company will drill past the Jurassic-age Kingak shale and the Cretaceous-age Hue shales.

“They are co-located meaning more or less on top of one another,” Duncan said. “From a drilling depth perspective we will drill down through the HRZ on the way down to the Kingak, on the way down to the Shublik.

“In phase one, the spacing between the wells (about four to a pad) will be 150 acres. In phases two and three, the company will use the same one-acre pads it used for phase one, but it will likely reduce spacing between wells to 80 acres (resulting in about 8 wells per pad),” Duncan said.

In phase three, sometime in the first 30 years from when development drilling gets under way — in 2013, if Duncan has his way — Great Bear will target one of the other two source rocks.

“The richest source rock on the North Slope and one of the richest source rocks in North America — in fact, one of the richest source rocks in the world — is the Shublik formation,” Duncan told legislators. “Its regional extent, its quality, is extraordinary. And that is our primary target.

“But, again, I can’t emphasize enough: we believe that the Kingak and the Hue individually could supply an unconventional resource development on their own. The fact that we have three on the North Slope provides … an extraordinary opportunity. You don’t get that in south Texas, you don’t get this in the Bakken and you really don’t get that in the Marcellus.”

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Salazar names ocean energy advisory committee members

Interior’s Ocean Energy Safety Advisory Committee to provide guidance on offshore drilling safety, well containment, and spill response.

The permanent advisory body consists of leading scientific, engineering, and technical experts who will provide critical guidance on improving offshore drilling safety, well containment, and spill response.

The committee has 15 members representing federal agencies, the offshore oil and gas industry, academia, national labs and various research organizations.

Representing the offshore industry are: Charlie Williams, chief scientist for well engineering and production technology, Shell Oil Co.; Paul Siegelle, Chevron’s Energy Technology Company; Joseph Gebara, senior manager, structural engineer, Technip USA Inc.; and Don Jacobsen, senior vice president operations, Noble Drilling Services Inc.

Members representing the academic community and nongovernmental organizations are: Nancy Leveson, professor, system safety and process safety, Massachusetts Institute of Technology; Richard Sears, senior science and engineering advisor and chief scientist, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling; Tad Patzek, professor and chairman, Department of Petroleum and Geosystems Engineering, University of Texas at Austin; and Lois Epstein, Arctic program manager, The Wilderness Society.

Federal Government designees on the committee are: Walter Cruickshank, deputy director, BOEMRE; Christopher Smith, deputy assistant secretary for oil and natural gas in the Office of Fossil Energy, Department of Energy; Capt. Patrick Little, commanding officer, Marine Safety Center, U.S. Coast Guard; Mathy Stanislaus, assistant administrator for Solid Waste and Emergency Response, Environmental Protection Agency; David Jacobsen, senior vice president operations, Noble Drilling Services Inc.; Don Gebara, senior manager, structural engineer, Technip USA Inc.; and Don Gebara, senior manager, structural engineer, Technip USA Inc.

Representing the public and private sectors who are keenly interested in the Arctic are: Tom Fritsch, president, Noble Drilling Services Inc.; and Steve Hickman, a geophysicist with the U.S. Geological Survey.

The committee’s current goals for the $400 million U.S. Arctic Research Program include an expanded federal emphasis on Arctic climate and Arctic Ocean research; improved oil spill prevention and response in ice-covered waters; and strengthened research into Arctic human health, indigenous languages and cultures.

“I am honored to serve as chair of the USARC, particularly during this time of increased attention on the Arctic and the rapid changes being observed in the region,” Ulmer said on March 10 in response to her appointment. “I look forward to working with the other commissioners and staff, and the many people in the public and private sectors who are keenly interested in the Arctic.”

“Fran brings an intimate knowledge of the Arctic’s environment, efforts to promote economic development in the region and the need for the U.S. to be a leader in the Arctic,” said Sen. Mark Begich, D-Alaska. “Having her as chair of the commission will help further our nation’s efforts to expand our role and harness our potential as an Arctic nation.”

—ALAN BAILEY

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GOVERNMENT

ACMP issues still at play in Juneau
The Alaska Coastal Management Program terminates July 1 unless extended by the Legislature.

The House Resources Committee is in the midst of hearings on a bill from the administration to extend the program for six years; an audit of the program by the Legislative Audit Division recommended a four-year extension; a bill by the Senate Finance Committee would extend the program by one year.

Finance co-Chair Lyman Hoffman, D-Bethel, said March 15 at a Senate Bipartisan Working Group press availability that he doesn’t think there is adequate time this year to address coastal zone issues, which is “why I’m supporting a one-year extension.”

If the program isn’t extended, “I guess we could address starting from scratch and building up a new program next year,” Hoffman said, adding that Alaskans, “particularly on the coast, I think unanimously are interested in more participation.”

Senate President Gary Stevens, R-Kodiak, agreed that the issue is an important one about which communities are quite concerned and want to be at the table.

“So there’s a long ways to go on that issue,” Stevens said.

In House Resources, hearings on House Bill 106, the governor’s bill to extend the program, are scheduled through March 25, and Resources co-Chair Paul Seaton, R-Homer, said March 16 that a committee substitute had been prepared.

In addition to earlier testimony from Randy Bates, director of the Department of Natural Resources’ Division of Coastal and Ocean Management, the committee heard from Legislative Auditor Pat Davidson on March 11 and from Glenn Gray, a consultant representing coastal districts, on March 16.

See coverage of the March 11 and March 16 and upcoming hearings in the March 27 issue of Petroleum News.

—KRISTEN NELSON

F I N A N C E & E C O N O M Y

Miller CEO hails Alaska energy climate
Parent company of Cook Inlet Energy announces receipt of $2 million state payment; also recoups $1.5M in tariff deal

Miller Energy Resources, which operates in Alaska via subsidiary Cook Inlet Energy LLC, recently announced it had received a tax credit payment of more than $2 million from the state.

The payment “validates Alaska as one of the most favorable development environments for energy today,” said Scott Boruff, Miller’s chief executive, in a Feb. 10 press release.

The payment “represents the combination of two submissions that covered the time period from December 2009 through July 2010 and in the first of several anticipated reimbursements under these new laws, as we are currently preparing our next applications for submission,” Boruff said.

He added that planned capital expenditures over the next 12 months “should also yield several million dollars in additional refund payments.”

Miller Energy trades as Miller Petroleum Inc. (MILL) on the Nasdaq stock exchange.

The company entered the Alaska scene in late 2009, when it financed Cook Inlet Energy’s purchase of an assortment of oil and gas properties previously operated by California-based Pacific Energy Resources Ltd., which liquidated through bankruptcy.

After a protest to the Regulatory Commission of Alaska, Cook Inlet Energy worked out a tariff settlement with CIPL in late 2010.

Contact Wesley Loy at wloy@petroleumnews.com
continued from page 1

**JACK-UP RIG**

Mexico — and the largest blowout preventer ever employed in Cook Inlet. The blowout preventer and all of its components added an additional $1.5 million to the cost of the program, Davis said at the time, noting it would be installed in Alaska.

He notified AOGCC the rig wouldn’t be fully assembled until it arrived in the state, which was acknowledged in a Feb. 25 letter from AOGCC to Davis, deferring inspection until the Spartan 151 was in Alaska.

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**Under an agreement with the Alaska Division of Oil and Gas, Escopeta must have the rig bound for Alaska by March 30 and must start drilling its first well by Oct. 31.**

Nonetheless, the preliminary inspection was made by AOGCC on March 9, at Davis’ invitation.

“At the time of inspection, Spartan 151 was undergoing modifications for Alaska operations,” Commissioners John Norman and Cathy Forster told Davis in a March 16 letter following the first inspection. “Key well blowout control equipment was missing from the rig. Commission representatives were advised that the missing equipment would be installed on the drilling unit when it arrives in Alaska. As such, a complete inspection of Spartan 151 was not possible.”

Under an agreement with the Alaska Division of Oil and Gas, Escopeta must have the rig bound for Alaska by March 30 and must start drilling its first well by Oct. 31.

The company wants to drill Kitchen Lights, an offshore unit in the upper Cook Inlet.

Escopeta is one of two independent oil companies looking to bring a jack-up rig to the Cook Inlet. Buccaneer Alaska is working on a financing plan with the Alaska Industrial Development and Export Authority and should have a deal ready for AIDEA board review soon.

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*PETROLEUM NEWS • WEEK OF MARCH 20, 2011*
Stoel Rives welcomes Iversen as tax partner

Stoel Rives, a full-service U.S. business law firm, said March 14 that it is pleased to announce Jonathan E. Iversen has joined its Anchorage office as a partner in the Litigation group.

Iversen focuses his practice on litigating tax matters. Before joining Stoel Rives, he served as director of the Tax Division of the Department of Revenue for the State of Alaska from 2007 to 2011. He has deep experience in complex tax matters and has litigated and negotiated settlements of major tax and royalty cases. Iversen served as a core team member in drafting Alaska’s oil and gas production tax and property tax laws and regulations. His practice also has an emphasis on oil and gas exploration, development and production matters, including royalties, leasing and unitization.

"Many of our resource industry clients frequently face significant tax disputes with the state. Adding Jon enables us to help them avoid, negotiate or, if necessary, litigate those disputes," said Anchorage office managing partner James E. Torgerson. "Jon has unparalleled insight into the development and structure of the state’s current tax regime. We’re delighted that he has joined us.”

Solstice names Tauke as production artist

Solstice Advertising, an Anchorage-based full-service advertising agency, said March 14 that it is pleased to announce Laura Tauke as its new production artist.

As a freelance graphic designer, Tauke’s talent has shined with her exhibit and design work at the Alaska SeaLife Center, the Academy of Hair Design and GrassRoots: A Fair Trade Store — just to name a few. Additionally, she co-owned and designed the original Alaska Outlaw Cards, a smashingly successful tourist knick-knack available at retail shops all over the state.

Following her childhood love of logos and brands and her dream to create her own, Tauke studied abroad in Rome, Italy, and received her bachelor of fine arts in graphic design from the College of Design at Iowa State University. Working first in Madison, Wis., before moving to Alaska to seek adventure, she brings an exciting and professional creative edge to the Solstice team, along with an eye for detail that helps clients’ projects break through the clutter.

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Laura Tauke
B and most of StatOil is owned by Norwegian. With higher oil prices, there is a greater schism between Alaska and the rest of the world, he said, so the higher the price of oil gets, the less competitive Alaska is, resulting in less oil being produced.

Companies have made billions of dollars in Alaska, Marks said, but the issue isn’t how much they can make in Alaska, it’s how much more money they could make in other places.

On the issue of ConocoPhillips’ Alaska profits compared to the Lower 48, Marks said it’s about the difference between oil and gas. In Alaska the company’s assets are more than 90 percent oil, compared to about one-third oil in the Lower 48 where the company primarily has natural gas assets and internationally, where the company has about 50-50 oil to gas. ConocoPhillips is relatively more profitable in Alaska because they have relatively more oil, he said, which is much more valuable than gas.

The worldwide competition for investment dollars, Marks said, is oil vs. oil.

Lots of money

Alaska is making lots of money now, Marks said, so what is the problem? When ACES passed in 2007 there was a lot of entrenched activity on the North Slope that wasn’t going anywhere. But people haven’t focused on what’s happening to production, he said.

Both the Department of Revenue and the Department of Natural Resources do production forecasts. DNR’s forecast has gone out to 2020 since 2000, and while it isn’t annual, there have been six forecasts since 2002, Marks said.

Marks compared a 2006 DNR forecast, the last prior to passage of PPT, in which projected production of 880,000 barrels per day was projected for 2010, dropping to some 675,000 bpd by 2020, which production of almost 900,000 bpd in 2010 was based on $50 per barrel oil, he said. With prices much higher than that, you’d think companies would want to produce more oil, but as oil prices go up, Alaska becomes relatively less competitive, Marks said.

He said the drop in DNR’s production forecast reflects a drop in investment, because developing individual fault blocks within core fields and developing heavy oil requires capital investment.

More money better than less

Marks said a basic cornerstone of economic theory is that more money is better than less money, so companies will do what makes them more money and ACES has created a structure that causes people to invest elsewhere.

As for fixing ACES, Marks told legislators he doesn’t believe you can fix ACES with more credits: Tax dwarfs credits, he said.

The problem is that taxes are too high, and you can’t fix too-high taxes by tinkering with credits — you need to fix the tax, he said.

And the problem isn’t progressivity, but with how progressivity is structured.

Marks noted that while the state has made changes in oil and gas taxes in the past, those changes have always decreased taxes, and said he appreciates it’s a hard-wringing experience.

He said he’s done his best to lay out the rationale for why lowering taxes makes sense — if people can make more money elsewhere they’ll go elsewhere.

But he noted that nationally both presidents Kennedy and Reagan proposed tax reductions which passed and the economy rebounded in both cases.

Alaska’s resource base is good, he said, so the question is do people have reason to come in and develop that oil vs. oil that they can develop in other places.

Contact Kristen Nelson
knelson@petroleumnews.com

Global Diving & Salvage responds to tsunami damage

Global Diving & Salvage Inc. said March 14 that it was engaged by the U.S. Coast Guard to respond to the destruction inflicted to Crescent City, Calif., by the 8-foot tsunami tidal surges generated by the 8.9 magnitude earthquake near Japan. The aftermaths of the tsunami impacted several areas along the West Coast of the United States causing significant damage to marine facilities and vessels unable to escape the onslaught.

Global has been tasked to assist with the removal of fuel, lubricants and other pollution threats from several of the stricken vessels that were sunk or severely damaged during the event. In response Global has mobilized diving and pollution mitigation equipment from their two California offices. Should conditions warrant, Global has the ability to cascade additional resources and personnel from several other company locations.

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

Meet Ed Becker

Meet Ed Becker
              ED HAS HIS HANDS FULL —

AND THAT’S BEFORE WEATHER THROWS HIM A CURVE.

As Assistant Principal and Activities Director of Tokumpaniguk School in Stebbins, Ed thinks of Era as a vital player in his community. "Era is a lifeline. They bring supplies and people to Stebbins, but they also offer the students their first exposure to life outside the village. That’s huge."

By working with Era to fly some of his 214 students to athletic and academic events, Ed can think less about getting to activities on time and more about the Grizzlies bringing home a win.

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Laptops for Foster Kids

Do you have an extra laptop you’d be willing to part with? No, I’m not adding to my own stockpile of consumer electronics or trying to strike it rich on the pawn shop circuit. Rep. Les Gara is working with Facing Foster Care Alaska to collect laptops for foster youth.

Laptops are a critical tool for foster youth to keep up with schoolwork and stay connected with family and friends while they are moved to different homes and schools.

If you are interested in donating a laptop, please make sure it is in excellent working order; is no more than 4 years old; has a word processing program; and does not need any repairs.

For more information, or to donate a laptop, please contact either Rep. Gara’s office at (907) 465-2647, or Amanda Metivier at Facing Foster Care Alaska at (907) 230-8237.
HEAVY OIL

at the bottom of a well, sucks a mixture of sand and oil to the surface from an unconsolidated sand reservoir, such as the Ugnu. The slurry of sand and oil reaching the wellhead is pumped to a heated separation tank, where the sand sinks out of the oil for removal and disposal.

Successful test

In 2008 BP successfully tested the CHOPS technique in a single well at S-pad, using standard oilfield equipment to process the produced material. But the new facility represents a considerable scaling up of that initial test, with the installation of custom-built heavy-oil production equipment. That equipment includes a system for minimizing fire risks by heating the facility’s separation tanks indirectly using a closed loop of circulating fluid.

BP had hoped to bring the facility into operation in May 2010 but it has taken until now to bring everything together, BP spokesman Steve Rinchert told Petroleum News March 14. The company expects to bring the first CHOPS well on line in mid-April, Rinchert said.

BP has drilled four wells for the testing at the new facility, with two of the wells being horizontal, West said. BP will put processed oil into the flow line for the Milne Point field, with waste sand being trucked to the Prudhoe Bay grind-and-inject facility for disposal.

The purpose of operating the pilot facility is to test the technical viability of heavy oil production, with the eventual aim of assessing the commercial feasibility of a future full-scale plant.

“We’re not quite sure what it is going to take commercially to make this work,” West said. “What we are focused on right now is proving technical viability.”

Needs light oil

Heavy oil, with a consistency of molasses, cannot flow unaided down a pipeline for transportation to market. And, although it might be possible to flow the product either by upgrading the oil in a North Slope refinery or by heating the transportation pipeline, BP does not view these options as commercially feasible, thus leaving the dilution of heavy oil production with light oil as the only commercial option for shipping the heavy oil from the slope.

“We are not quite sure what it is going to take commercially to make this work,” —ALAN BAILEY

Those pesky oil bacteria at work

Heavy oil, such as that found in the Ugnu formation on Alaska’s North Slope, is formed when bacteria gobble up the lighter, hydrogen-intensive components of regular light oil, leaving behind a residue of the heavier oil components and producing large volumes of methane in the process, Eric West, manager of BP’s Alaska renewal team, told a group of state legislators during a presentation on heavy oil on March 10 in Juneau.

The bacteria cannot survive the relatively high temperatures encountered in the deeply buried reservoir rocks of oil fields such as Prudhoe Bay and Kuparuk, so that the oil in these fields has remained relatively light, easily flowing up wells and through pipeline systems.

But over time, some oil has spilled from these deep field reservoirs, percolating upwards through the rock strata into relatively shallow rock formations such as the West Sak-Schrader Bluff and the Ugnu, West said. And the shallower the resulting oil pools, the cooler the oil becomes. Conversely, the cooler the oil, the more active and abundant the bacteria become in chomping at the light oil components.

The West Sak-Schrader Bluff formation now hosts what BP refers to as viscous oil, oil with a consistency of maple syrup that can be produced, especially through horizontal wells that access large sections of reservoir. Heavy oil, with the consistency of molasses and unable to flow unaided, is found in the shallower Ugnu formation.

The methane from the bacterial flows upwards to the base of the permafrost, where it combines with water to form methane hydrate, a potential future source of commercial natural gas.

—ALAN BAILEY

But commercial production of heavy oil will face some significant challenges. Heavy oil has less of the light, high-hydrogen components, valued for refining into high-value products such as gasoline, than does light oil, thus giving the heavy oil a lower market value than its lighter cousin. In addition, the production and usage of heavy oil would involve the use of the same value chain of pipelines, oil tankers, refineries and so on as light oil, but with new (and costly) technology bolted on — heavy oil is unlikely to ever be more economic than light oil, West said.

“Heavy oil is not light oil that happens to weigh more,” West said. “It is in fact a different commodity. It has different technical challenges.”

And although BP’s test facility should this year provide some clarity over what the physics of heavy oil production from the Ugnu works, it will likely take another couple of years, and perhaps another pilot project, to flesh out the production characteristics of the heavy oil resource, he said.

On the other hand, the heavy oil production, at its peak, could add 250,000 barrels per day to overall North Slope production.

“There should be able to deliver that, it represents a renaissance and rejuvenation of the Alaska North Slope fluids business,” West said. “It’s a really large resource and we are committed to making it work.”

—ALAN BAILEY

Contact Alan Bailey at abailey@petroleumnews.com

MARCH 20, 2011
Critical time

Carri Lockhart, production manager for Marathon Oil Co. in Alaska, agreed, saying that the winter of 2011-12 will be the critical time for gas deliverability — the rate at which gas can be delivered. Much will hinge on whether the weather remains mild. Supply issues will be reversed when well flow slackens in the summer, ConocoPhillips has accelerated again to an annual rate of about 11 percent this winter, Clark said.

“Next winter there’s going to be a challenge in any circumstance, regardless of what the market does and everything else,” Clark said.

Daniel Helmick, manager of regulatory affairs for Municipal Light & Power, said that the utilities would not be surprised if they need to import LNG by 2013 or 2014.

LNG imports

Lee Thibert, senior vice president of Chugach Electric Association, said that the Southcentral utilities are working together on various options to address the tightening gas supply situation, with the conversion of the LNG plant for import of LNG being one of the possibilities.

“We’re all working very diligently, trying to look at all the options … trying to get something decided here, hopefully this summer,” Thibert said.

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energy in focus

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It’s a small market. There’s no doubt about it,” Lockhart said. “Cook Inlet will always be challenged in that regard of not having a massive market that’s fully open, like in the Lower 48.”

Lockhart said that, in addition to maintaining its gas storage facility in the Kenai gas field to bolster winter gas deliverability, Marathon has worked on its gas wells to enable the curtailment of gas production in the summer to lower levels than would otherwise be possible without damaging the wells. The company is also installing a bidirectional meter in the Kenai Niskik pipeline on the Kenai Peninsula, to allow more flexible use of its storage facility, Lockhart said.

Daniel Helmick, manager of regulatory affairs for Municipal Light & Power, said that gas demand slackens in the summer, ConocoPhillips will preferentially maintain production from those gas wells that produce water along with gas, because those wells are most likely to suffer damage if shut-in.

Colleen Starring, president of Enstar Natural Gas Co., said that any damage to wells following well shut-ins could jeopardize Enstar’s ability to buy gas at short notice, to meet high winter demand.

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continued from page 1

NORTH TARN

No. 1 by mid-April, but also said it could also end up drilling a sidetrack to the well this winter, depending on results.

“The BRPC Group is optimistically looking forward to see the results of the North Tarn No. 1 exploration well,” said Jim Winegamer, vice president of land and external affairs for BRPC. “The North Tarn No. 1 exploration well is the only exploration well being drilled on the North Slope this season; therefore, the BRPC Group holds the title on the North Tarn’s exploration company. We’d rather share that title with many more companies.”

— Jim Winegamer, vice president of land and external affairs for BRPC

continued from page 1

MAC GAS

That opens the way for negotiations to resume on a federal fiscal framework, the completion of engineering and field work and a start to the process of obtaining about 6,300 permits and authorizations.

The partnership has until the end of 2013 to decide whether to give the final go-ahead and to end of the 2015 to start construction, which would likely bring the project onstream in the 2018-20 period, delivering 1.2 billion cubic feet per day to southern markets.

Imperial looking for balance

The partners are Imperial Oil 34.4 percent, Aboriginal Pipeline Group 33.3 percent, ConocoPhillips Canada 15.7 percent, Shell Canada 11.4 percent and ExxonMobil Canada 5.2 percent.

Imperial is “very pleased” to have the regulatory approval and will now focus on seeking an agreement with the Canadian government on a fiscal framework to “provide an appropriate balance of risk and benefit” for both sides, a spokesman said, while emphasizing that there is a long road ahead.

Doug Matthews, a Calgary oil and gas analyst, told the Canadian Broadcasting Corp. earlier this year that the Canadian government has failed to sell the MGP to taxpayers.

“I think there’s very little support, certainly within the federal government, for significant financial injections into this project. And that’s just too bad,” he said. “You’re hard pressed to think back to a cabinet minister really going public with strong support for the MGP.”

Despite recent signs of renewed support for the MGP, FirstEnergy Capital analyst Steven Paget said the outlook for the North American gas market is more crucial than the regulatory formalities.

He said shale gas projects, which are much closer to existing infrastructure and major population centers than the MGP, are likely to proceed first.

Paget said the MGP would need gas prices of $6-$8 per thousand cubic feet to proceed and that is not likely before at least 2015 and, according to Canadian Natural Resources, possibly as late as 2018.

Alberta Energy Minister Ron Liepert said the current price of gas does not justify either the Mackenzie or Alaska pipelines.

“There are challenges to overcome and they are economic rather than environmental or land concern issues,” he said. Joe Marushack, Canadian president for ConocoPhillips, said earlier in March the MGP is a “pretty tough project” given where gas prices stand.

— GARY PARK