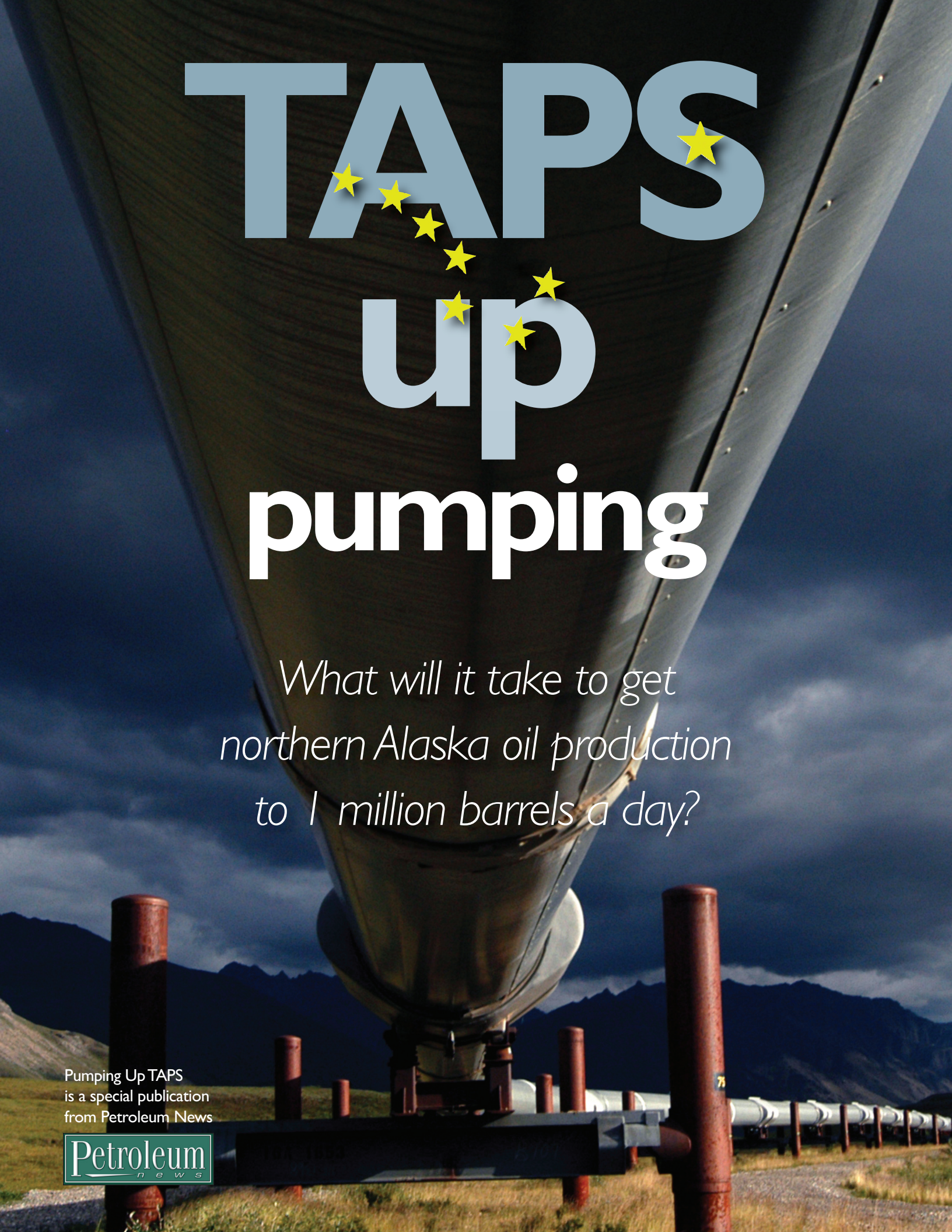

TAPS up pumping

What will it take to get northern Alaska oil production to 1 million barrels a day?

Pumping Up TAPS
is a special publication
from Petroleum News

Petroleum news

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Less about pumping up than stabilizing flow

By KAY CASHMAN
Executive editor & publisher of Petroleum News

This magazine started out as an attempt to identify the potential sources of oil that could meet Gov. Sean Parnell's goal of getting 1 million barrels of North Slope oil per day in the Trans Alaska Pipeline System, or TAPS, within 10 years.

But it soon became more about whether it was possible to stem the decline from an expected average production in 2011 of 605,000 bpd to 530,000 bpd in 2020, as projected in the Alaska Department of Revenue's spring 2011 forecast.


KAY **CASHMAN**

What I learned in my research was that it might be possible to meet the governor's goal in a 10-year period, but only if production from Alaska's source rocks and offshore comes off without any major hitches or delays.

Not wanting to bet on something exciting, but completely untried on the North Slope, and with geologic, technical, economic and political challenges, I decided not to include shale oil in production numbers for the next decade.

Shell, the lead company in northern Alaska's offshore development, could conceivably have one or two Beaufort Sea fields in production in 2021, but even Shell predicts the start of its outer continental shelf Chukchi oil production is at least 10 years out IF it can drill in the open water season of 2012 and there are no more permitting, lawsuit or other delays.

That's more than a long shot, so I excluded the OCS.

Explorers such as Repsol and Brooks Range Petroleum will certainly play a part in putting new oil in the pipeline, so they were included — sort of, as it's not clear they will develop and produce all their discoveries without a change in Alaska's production tax.

BP and ConocoPhillips, which operate the fields currently producing 98 percent of the oil going into TAPS, could step up production in their legacy fields and increase investment in heavy oil, but the opposite is actually happening — both companies are unwilling to increase their capital investment because they say Alaska's production tax, commonly known as ACES, is a disincentive. Until it is changed —until the governor's legislation, House Bill 110, has passed into law — the companies say they will not be stepping up investment.

Worse, BP predicts the decline in North Slope production will be greater than Revenue projected because 52 percent of the oil between 2011 and 2020 in the state's spring 2011 forecast was from projects not yet sanctioned, and many of those were BP or ConocoPhillips projects that are now on hold. Revenue's fall forecast was due out after all pages except the On Deadline section of this magazine had gone to press. I expected output of 474,000 bpd in 2020, which was the last year in the spring forecast, but you can find out for sure by checking page 8.

So, this magazine became more about investigating whether the decline in North Slope oil production can be halted, especially without the cooperation of BP and ConocoPhillips, than it did about achieving the governor's goal.

Increase in tariff would hurt investment

Less oil in TAPS means less revenue for the state and possible mechanical problems in the line.

But trying to keep production flat at 605,000 bpd is not just about protecting state revenues or avoiding unexpected flow problems; it's also about the trans-Alaska pipeline tariff for non-TAPS owners, such as Repsol, Pioneer Natural Resources, Savant, Brooks Range, Eni, Linc, UltraStar, Great Bear, Shell, Statoil, ASRC Exploration and others. The tariff will undoubtedly go up as system costs are shared among fewer and fewer barrels of oil, which is a disincentive for non-TAPS owners to produce oil on the North Slope.

And if TAPS operator Alyeska Pipeline Service Co.'s low flow impact study is correct (see story on page 23), there is a whole list of mitigation measures that Alyeska will have to implement to keep the pipeline operating as throughput drops below 600,000 barrels a day — costly mitigations that could also raise the tariff.

Subsidiaries of the North Slope's largest producers, BP, ConocoPhillips and ExxonMobil, own large chunks of TAPS, so a higher tariff is not going to necessarily sour them on Alaska. But it has driven off other operators in the past, including Conoco before it was ConocoPhillips and owned ARCO Alaska's share of TAPS — just as a drop in the tariff due to agency and court decisions helped attract new players to Alaska, starting in 2000.

So, this magazine became more about investigating whether the decline in North Slope oil production can be halted, especially without the cooperation of BP and ConocoPhillips, than it did about achieving the governor's goal.

The first article, an analysis by me, is titled, "First, can the decline be halted? BP, Conoco operate 98 percent of northern Alaska oil production: can it be done without them?"

The next three articles deal with related subjects — oil prices, drilling rig shortages, and TAPS potential low-flow issues.

The next article is about the governor's five-point strategy to achieve his goal, followed by articles about the various sources of oil that could help stem the decline and/or reach the 1 million bpd target.

Finally, there is a group of opinion and analysis pieces that cover everything from impediments to filling TAPS by Jim Weeks, to Rep. Les Gara's position that HB 110 is a giveaway, to Dan Dickinson's five not-so easy pieces to put 1 million barrels in the pipeline, and more.

In the end, we have a photo layout about TAPS, from construction, to start-up, and snapshots of the last 34 years of operation.

I hope you enjoy this magazine, and find it helpful in understanding the incredible challenge in pumping up TAPS.

Pumping Up TAPS

Released Jan. 6, 2012

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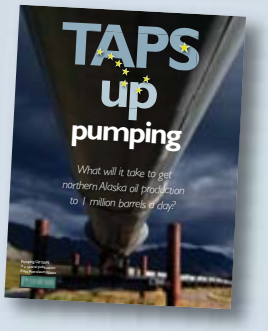

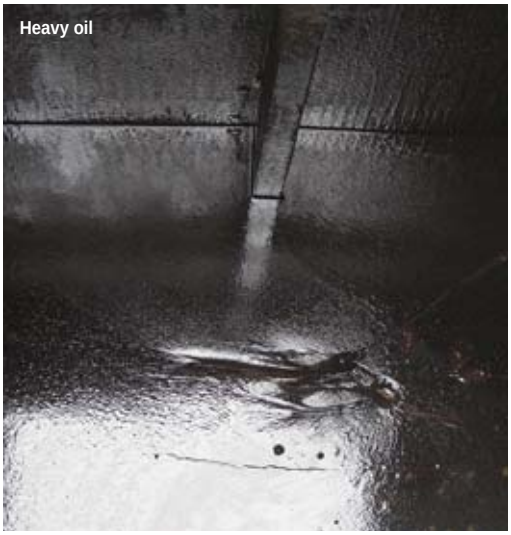
Heavy oil


The Oooguruk field


Parnell


Sullivan


Shell's Frontier Discoverer

Petroleum news

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Production drops to 458,000 bpd

Revenue's fall forecast for North Slope crude down considerably from spring forecast

By KRISTEN NELSON
Petroleum News

The Alaska Department of Revenue's fall forecast shows a sharp decrease in forecast production compared to the spring forecast, with Alaska North Slope crude oil volumes dropping below 600,000 barrels per day beginning in the current fiscal year, 2012. In the spring forecast, Revenue was projecting production of more than 600,000 bpd through fiscal year 2017. (See story on page 10.)

The final year of the spring forecast, FY 2020, shows production of 530,000 bpd; the fall forecast shows projected production dropping to 486,000 — the first projection below 500,000 bpd — in FY 2020. Production falls to 458,000 by FY 2021.

One change between spring and fall is when production is expected from BP Exploration (Alaska)'s Liberty prospect east of Endicott and from ConocoPhillips Alaska's west side CD-5 project in the National Petroleum Reserve Alaska.

In the spring, Liberty production was shown as beginning in FY 2013. The fall forecast wraps Liberty into an offshore category which includes Northstar, Liberty, Nikaitchuq and Oooguruk, and while Liberty isn't noted separately, the first uptick in production from the offshore category comes in FY 2016, peaking in 2017. The spring forecast showed a similar pattern, with Liberty production beginning in one year and peaking in the next and the uptick volumes are similar to standalone Liberty forecast from the spring forecast, which showed a peak of 39,000 bpd.

NPR-A production, shown in the spring forecast as beginning in FY 2015, is shown in the fall forecast as beginning in 2017 and peaking in FY 2019.

The final year of the spring forecast, FY 2020, shows production of 530,000 bpd; the fall forecast shows projected production dropping to 486,000 — the first projection below 500,000 bpd — in FY 2020. Production falls to 458,000 by FY 2021.

Only Kuparuk the same

For producing fields, only the Kuparuk forecast remains the same, 87,000 bpd in FY 2012, dropping down through 83,000 and 81,000 bpd in FY 2014, with some differences in the out years, but nothing substantial.

Prudhoe Bay stood by itself in the spring forecast; in the fall forecast it includes production from Milne Point, so while Prudhoe numbers would appear to be up, they are actually down compared to the combined Prudhoe-Milne spring forecasts.

Prudhoe is forecast to produce 276,000 bpd in FY 2012, down from 297,000 in the spring forecast. The FY 2013 fall forecast shows 269,000 bpd, down from 284,000 in the spring forecast; the downward trend (both overall and compared to the spring forecast) continues through 2020, the last comparison year.

Prudhoe Bay satellites are also forecast to produce less in the fall forecast, from 37,000 bpd in 2012 to 16,000 bpd in 2020 in the spring forecast down to 36,000 bpd for 2012 in the fall forecast and dropping off to 18,000 bpd in 2020 in the fall forecast compared to 27,000 bpd in the spring forecast.

A change in direction for ConocoPhillips?

ConocoPhillips' participation in the State of Alaska's Dec. 7 North Slope and Beaufort Sea areawide lease sales raised eyebrows since by 2002 the newly merged ConocoPhillips, which had picked up ARCO's Alaska assets two years earlier through Phillips, had begun concentrating on finding "new" oil in its legacy units in the state, such as Prudhoe and Kuparuk. The company was still exploring, but on federal acreage, looking for big fields and dropping its state exploration acreage unless it was close to one of its producing units.

Over the next decade ConocoPhillips dropped even its Beaufort Sea federal leases and pulled back from wildcat exploration in the National Petroleum Reserve-Alaska, concentrating on its step-out development of the Colville River unit into NPR-A.

It looked to its federal leases in the Chukchi Sea for its next giant oil discovery in Alaska.

So, given its position on Alaska's current production tax, ConocoPhillips participation in the latest lease sales was a bit of a shocker.

The company bid unsuccessfully in partnership with Exxon on just one tract in the Beaufort Sea sale, but was high bidder on 35 tracts in the North Slope sale, with the bulk of the tracts in a large block south of Point Thomson and Badami on the eastern North Slope in the Slugger/Jacob's Ladder area. (In October, Alaska Venture Capital Group, or AVCG, relinquished a number of leases in the area from its proposed Greater Bullen unit, and some Anadarko leases in the area expired this year.)

Subject to economic evaluation

Although some of the bidders in the sale appear to have been consolidating existing lease positions, ConocoPhillips was clearly establishing a new position in known, but undeveloped, areas of interest.

"That's acreage that we have looked at in the past and when it became available we chose to bid on it," ConocoPhillips Exploration Manager Michael Faust told Petroleum News senior reporter Alan Bailey after the lease sale.

The region is prospective for oil — to the north of ConocoPhillips' new leases AVCG's operating company, Brooks Range Petroleum, is hoping to develop some known oil resources between the Point Thomson and Badami oil fields.

But Faust said the acquisition of state onshore leases to the

continued on next page

Stedman's position softening, interested in legacy field incentives

Editor's note: The following is an update to the Stedman sidebar on page 53.

Sen. Bert Stedman, R-Sitka and co-chair of the powerful Finance Committee, was surveyed in early December by the Associated Press, along with the 19 other members of the Alaska Senate, about Gov. Sean Parnell's legislation to cut oil production taxes in the upcoming legislative session. The House has already passed the legislation, HB 110, but Stedman and other senators wanted more information before they moved to change the state's production tax.

Stedman told AP that he plans to look at range of issues, including progressivity, tax credits and whether the state should continue taxing oil and gas production together.

Stedman also is interested in potential incentives to boost incremental production from Prudhoe and Kuparuk, AP reported. He said those fields, and possibly Alpine, are key to increased production through the trans-Alaska oil pipeline that delivers North Slope crude to tidewater.

Work has continued on the oil tax issue during the interim, and the upcoming 90-day session, which starts in January, is ample to move legislation, if that's what lawmakers decide is best for the state, he said.

"But we want to be careful we don't make the situation worse," Stedman said.

In addition to co-chairing Finance, Stedman sits on the Resources Committee, which probably will hear the governor's bill, and is a member of the Rules Committee, which will have the final decision on moving it to the Senate floor for a vote.

—Kay Cashman

CHANGE *continued from page 8*

east of Prudhoe Bay does not mark some new strategic direction for ConocoPhillips — the lease purchase was simply a case of snapping up some attractive acreage that became available.

The company will now evaluate the leases, identifying drillable prospects that can be added to the company's worldwide portfolio of exploration opportunities, Faust said.

The company already owns 3-D seismic data for the area, ConocoPhillips Land Manager David Brown told Bailey.

Faust said that funding to drill would depend on how the prospects in the leases compare with exploration opportunities elsewhere, and that the state's ACES production tax would be a factor in that comparison — ConocoPhillips wants to see changes in the progressivity elements of ACES.

—Kay Cashman

Editor's note: The Dec. 7 lease sale brought three new players to the North Slope, and added acreage to existing leaseholders' portfolios. In addition to ConocoPhillips' surprising exploration acreage grab, Shell picked up a substantial block of leases in state waters on the west side of Harrison Bay — the first state leases in recent history that Shell has owned offshore the North Slope. The tracts were previously leased by Talisman subsidiary FEX and will likely not go into production in the next decade because they are too far west of existing infrastructure. See articles and a map in the Dec. 11 edition of Petroleum News.

First, can the decline be halted?

BP, Conoco operate 98% of northern Alaska oil production: can it be done without them?

ANALYSIS By KAY CASHMAN
Petroleum News

Before determining if it's possible to increase flow in the trans-Alaska oil pipeline from projected 2011 levels of about 605,000 barrels a day to 1 million barrels, the governor's goal, it's important to first determine if the decline in North Slope production can be halted — specifically, stabilized without increases in investment from the region's two major operators, BP and ConocoPhillips, which with ExxonMobil and their smaller partners account for almost 98 percent of the liquids in the pipeline.

Executives from BP and ConocoPhillips say they do not expect to increase their capital spending in Alaska until the state's production tax is reduced.

BP, ConocoPhillips and ExxonMobil, the largest producers in the fields BP and ConocoPhillips operate, say the state's production tax — Alaska's Clear and Equitable Share, or ACES — takes away the incentive to invest at high oil prices, which they are ably demonstrating is true by not increasing capital investment in their North Slope legacy fields.

GOV. SEAN **PARNELL**

JUDY PATRICK

TROND-ERIK **JOHANSEN**

All three producers support Gov. Sean Parnell's proposed legislation to, as they describe it, "reform" ACES. House Bill 110 reduces the tax by changing how progressivity is applied, capping it and establishing a lower base rate for new fields.

HB 110's companion bill in the Senate, SB 49, went nowhere during the first regular session of this two-year legislative term, but is expected to be the major focus of that body in January, when the Legislature convenes.

Detractors of HB 110 say ACES is working, BP and ConocoPhillips are making big profits in Alaska, and that the two largest operators are holding the state hostage with the tax bill.

It doesn't matter who's right

I say, it doesn't matter who is right.

The fact is, without added investment by the three largest producers on the North Slope, their production, at least, is going to fall.

But if there are "improvements in the fiscal regime" in Alaska, ConocoPhillips Alaska President Trond-Erik Johansen said Nov. 16, "you will see more action. … You will see more drilling; you will see more projects. … That's just the way capitalism works."

So, let's look at current and projected oil production for the North Slope. (For simplicity's sake, in this article the "North Slope" includes all oil fields north of the Brooks Range in Alaska, including offshore pools.)

State says 12.4%; BP says 25%

In November, North Slope production averaged 624,687 barrels per day, down 6,850 barrels from the 631,537 bpd in November 2010, which is slightly more than a 1 percent drop, month to month. Over the last year throughput in the trans-Alaska oil pipeline dropped 7-8 percent, Johansen said.

The Alaska Department of Revenue's spring 2011 forecast predicts production will drop from a daily average of 605,000 barrels

continued on page 12

Trans-Alaska oil pipeline

JUDY PATRICK

North Slope producing units, operators

Unit	Operator
Badami	Savant
Colville River	ConocoPhillips
Endicott/Duck Island	BP
Kuparuk River	ConocoPhillips
Milne Point	BP
Nikaitchuq	Eni
Northstar	BP
Oooguruk	Pioneer
Prudhoe Bay	BP

What is a unit?

A unit is composed of a group of leases covering all or part of an accumulation(s) of oil or gas. The lessees agree to operate the leases as a single unit, under an approved plan of exploration or plan of development from state and/or federal authorities. Updated plans have to be submitted annually by the designated operator of the unit. Lessees have to apply to the appropriate government agency to form a unit. For the State of Alaska, the supervising agency is the Division of Oil and Gas in the Alaska Department of Natural Resources. The only federal producing unit north of the Brooks Range is the Northstar unit, which is jointly managed by the Bureau of Ocean Energy Management (formerly the U.S. Minerals Management Service), part of the U.S. Department of the Interior, and the state Division of Oil and Gas.


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a day in 2011 to 530,000 barrels a day by 2020, a decline of 12.4 percent.

But Claire Fitzpatrick, chief financial officer and senior vice president of BP Exploration (Alaska), predicts a 25 percent drop in oil production between now and 2020 for BP-operated fields on the North Slope, and a 7-8 percent decline in the next couple of years.

Fitzpatrick reminded attendees of the mid-November Resource Development Council conference that fields operated by BP account for about two-thirds of current North Slope production, meaning she's in a position to know how much oil is likely to be produced.

What's the difference?

Why the big difference between the Department of Revenue and BP's production estimates for 2020?

According to Fitzpatrick, Revenue's estimates include some "big buts" — that 52 percent of the department's forecast for 2020 is from projects under development or evaluation, including projects in existing producing fields. (See figures 6, 7, and 9 from Revenue's spring 2011 forecast, which support what she says.)

JUDY PATRICK

CLAIRE **FITZPATRICK**

A lot of the "under development" has not yet had final investment decisions from the owner companies, she says.

So, Fitzpatrick concludes, more than half the oil the state is banking on in 2020 comes with a big "If."

That means that more than half the production in the spring forecast — and therefore a big chunk of projected state revenues — depends on investments yet to be made.

"I don't know what the next DOR forecast is going to show in terms of decline over that timeframe. I do know what my forecast shows, and we are showing a steeper decline over that period than I was at this time last year," Fitzpatrick says.

"We've reviewed our plans and activities much more rigorously in terms of what's possible versus what's realistic in the current business climate," she says, meaning some of the projects BP talked to Revenue about prior to the spring forecast are now off the table.

On Dec. 1, Revenue officials confirmed that the latest Revenue forecast, due to be released in mid-December, will reflect a much lower production rate in 2020. (Pumping up TAPS goes to press on Dec. 9, but we're holding space in the On Deadline section near the beginning of this magazine to report on Revenue's latest forecast.)

Still, some new oil will most certainly be produced, with or without, a tax change. The ExxonMobil-operated Point Thomson field, for example, will likely be produced under a settlement agreement with the state of Alaska — that's 2,000 barrels a day in 2015 and 9,000 barrels thereafter, per Revenue's spring 2011 forecast.

And after all ConocoPhillips' work to get approval to build a bridge across the Colville River in order to start producing oil from CD5 in the National Petroleum Reserve-Alaska, where it is eligible for ACES tax credits, it's safe to assume ConocoPhillips will move forward with NPR-A exploration and development. In Revenue's spring 2011 forecast, that's 10,000 barrels a day in 2015, 65,000 barrels by 2020, including production from Linc Energy's Umiat oil field.

Even BP expects to proceed with its Liberty project in federal waters, which Revenue shows at 5,000 barrels a day in 2013, then peaking in 2014 at 39,000 barrels, and dropping to 14,000 barrels in 2020.

Still, a 25 percent drop in two-thirds of 98 percent of North Slope production by 2020 is considerable. And BP, remember, has to approve most of the investments in the ConocoPhillips-operated fields because it's a working interest owner in many of them. ("Has to approve" is not a legal mandate; but the unit owner relationship is much like a marriage. "Sure you can buy that pool table, honey, but….")

Oil BP, Revenue not including

Production from the only oil fields not operated by BP or ConocoPhillips on the North Slope — Eni's Nikaitchuq unit, Pioneer Natural Resources' Oooguruk unit and Savant's Badami unit — are included in the Department of Revenue's forecast.

Revenue's projections put Oooguruk and Nikaitchuq at a combined daily average of 19,000 barrels in 2012, up from 12,258 in November, and peaking at 38,000 barrels a day in 2014.

But Pioneer's Nuna development, which is inside the Oooguruk unit, and Savant's Red Wolf prospect, part of the Badami unit, are not in the forecast.

More important, not a drop of oil from the North Slope's active explorers — Repsol, Brooks Range Petroleum, UltraStar Exploration, ASRC Exploration and Great Bear Petroleum — is included in Revenue's forecast, per Victoria Ferguson, a petroleum econo-

continued on page 14

State spring revenue forecast

Figure 6. Alaska North Slope Production, FY 2010 and Forecasted FY 2010-2020 (1)
Million barrels/day

Fiscal Year	Currently Producing	Under Development	Under Evaluation	Total ANS
2010	0.644	0.000	0.000	0.644
2011	0.578	0.027	0.000	0.605
2012	0.517	0.087	0.006	0.610
2013	0.461	0.124	0.019	0.603
2014	0.425	0.177	0.028	0.630
2015	0.385	0.185	0.044	0.614
2016	0.353	0.186	0.090	0.629
2017	0.322	0.177	0.121	0.619
2018	0.296	0.168	0.133	0.598
2019	0.273	0.161	0.129	0.564
2020	0.254	0.155	0.121	0.530

Figure 7. New Oil as a Percentage of Total Oil (2)
Million barrels/day

Fiscal Year	Total New Oil	ANS Total	Percent New Oil
2011	0.027	0.605	4.5%
2012	0.093	0.610	15.3%
2013	0.143	0.603	23.7%
2014	0.205	0.630	32.5%
2015	0.229	0.614	37.3%
2016	0.276	0.629	43.9%
2017	0.297	0.619	48.0%
2018	0.302	0.598	50.5%
2019	0.290	0.564	51.5%
2020	0.276	0.530	52.0%

(1) Some of the oil forecasted in the Under Development and Under Evaluation categories are from new projects in fields currently producing.

(2) "New Oil" is the sum of the Under Development and Under Evaluation categories.

DECLINE *continued from page 12*

mist with the department.

With the exception of ASRC, all these companies are planning to drill exploration wells this winter; although as of Dec. 1, two of the explorers will probably not be able to find drilling rigs, bumping their wells to the winter season of 2012-13.

Potential production from these seven companies' projects, some of which are unitized and have been previously drilled, do not meet Revenue's standards for inclusion in its forecasts, Ferguson says, providing a list of those standards:

A. Reservoir delineation through new penetrations, drill stem testing and seismic.

B. The reservoir should be fairly well defined and proved to have productive capabilities

C. The operator should have fairly concrete development plans in place.

Great Bear production excluded

Despite the Parnell administration's enthusiasm for Great Bear's source rock exploitation plans, the company has to prove it can produce oil from the formations on the North Slope, Ferguson says.

"Since production from source rock is considered unconventional, we will wait for some extensive, definitive production data from a pilot project before we forecast any significant production from the Great Bear properties," she says.

Those standards make sense when you're looking for absolutes. Even ignoring Great Bear's very bold production estimates makes sense, although its project could potentially reverse the decline on its own, and more, within the 2015 to 2020 timeframe.

Still, Great Bear is proposing to produce oil from source rock; something that has never before been done on the North Slope. And given the difference in the cost of operating in northern Alaska versus in North Dakota's Bakken or Texas' Eagle Ford shale plays, Great Bear might need the tax breaks in the governor's bill to make its Alaska project economic.

Ed Duncan, Great Bear's president and chief operating officer, told legislators in February that competition for capital is on a global scale, and while Alaska presents an opportunity for oil and gas investment, "we also see a great opportunity for Alaska to improve its position globally" by making the tax changes proposed in HB 110.

Alaska is prospective for development because "it has some of the best rocks in one of the best petroleum provinces in the world." But, Duncan says, "it also has some fiscal terms that are suppressing development."

The risk in Great Bear's source rock exploitation plans is not technical but "commercial viability in competition for capital (because it) requires capital to make this play really happen," he says, describing the play as both capital intensive and labor intensive.

"This is an opportunity to deliver a play that has long-lived production; manageable risk; allows the state to forecast forward revenue; (and) has tremendous job growth associated with it — if we can make it happen."

The objective of Great Bear's exploration and evaluation program is to run short tests on at least four wells, with those tests potentially leading to the sanctioning of a pilot plant to more fully determine the production characteristics of the rocks, Duncan told Petroleum News in November.

It will be necessary to obtain at least a one-year production profile, determining parameters such as production decay characteristics, as well as assessing the economic feasibility of oil production from the rocks, before making a decision to move to full field development, which he says could occur in 2015.

A 123,000 barrel a day difference

If you're looking to leave ACES as is, you have to know whether the other explorers, all of which have access to adequate funding and two of which are already producing oil in the region, have a chance of filling the gap between 2011's projected average of 605,000 barrels of oil flowing through the Trans-Alaska Pipeline System, or TAPS, and what will be running through it daily in 2020.

Cutting another 8 percent off 605,000 barrels a day in deference to Fitzpatrick, another 48,000 barrels are deducted from Revenue's projected 530,000 barrels, for a drop to 482,000 barrels a day between now and 2020.

That's a difference of about 123,000 barrels a day. (Maybe more, maybe less: Remember to check out the On Deadline section at the front of this magazine with Revenue's latest forecast.)

In 10 years, Alaska might see some federal outer continental shelf production from Shell, but Shell says that's only if nothing goes wrong between now and then, and it can drill in 2012. It would be foolish to count on Beaufort and Chukchi OCS oil in the next decade, but if Shell picks up Beaufort Sea leases in the Dec. 7 state sale,

State spring revenue forecast

Figure 9.
Crude Oil Production, FY 2010 & Forecasted FY 2011-2020

million barrels/day

FY	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Prudhoe Bay (1)	0.277	0.271	0.272	0.259	0.256	0.243	0.231	0.218	0.208	0.198	0.189
PBU Satellites (2)	0.036	0.030	0.037	0.048	0.050	0.050	0.049	0.042	0.036	0.031	0.027
GPMA (3)	0.034	0.031	0.031	0.029	0.026	0.024	0.022	0.020	0.018	0.017	0.016
Kuparuk	0.099	0.091	0.087	0.084	0.081	0.079	0.077	0.075	0.072	0.069	0.067
Kuparuk Satellites (4)	0.035	0.032	0.031	0.028	0.026	0.023	0.023	0.033	0.031	0.028	0.025
Milne Point (5)	0.028	0.025	0.025	0.025	0.025	0.026	0.028	0.028	0.028	0.027	0.024
Endicott (6)	0.013	0.015	0.017	0.016	0.016	0.016	0.017	0.014	0.012	0.011	0.010
Liberty	0.000	0.000	0.000	0.005	0.039	0.037	0.029	0.024	0.020	0.017	0.014
Alpine (7)	0.058	0.057	0.053	0.045	0.043	0.044	0.040	0.036	0.032	0.029	0.027
Fiord (8)	0.024	0.026	0.026	0.022	0.019	0.016	0.016	0.021	0.027	0.026	0.022
Nanuq (9)	0.011	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
NPR-A (10)	0.000	0.000	0.000	0.000	0.000	0.010	0.047	0.057	0.064	0.065	0.065
Offshore (11)	0.009	0.012	0.019	0.031	0.038	0.037	0.035	0.035	0.035	0.033	0.031
Pt.Thomson	0.000	0.000	0.000	0.000	0.000	0.002	0.009	0.009	0.009	0.009	0.009
Northstar (12)	0.020	0.015	0.013	0.011	0.009	0.007	0.006	0.005	0.005	0.004	0.004
Pt.Thomson Satellites	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total ANS	**0.644**	**0.605**	**0.610**	**0.603**	**0.630**	**0.614**	**0.629**	**0.619**	**0.598**	**0.564**	**0.530**
Cook Inlet	**0.009**	**0.010**	**0.009**	**0.008**	**0.008**	**0.007**	**0.007**	**0.006**	**0.006**	**0.006**	**0.005**
Total Alaska	**0.653**	**0.615**	**0.620**	**0.612**	**0.638**	**0.622**	**0.636**	**0.626**	**0.604**	**0.570**	**0.536**

(1) Includes NGLs from Central Gas Facility shipped to TAPS
(2) Aurora, Borealis, Midnight Sun, Orion and Polaris
(3) Lisburne, Niakuk, North Prudhoe Bay State, Point McIntyre, Raven, West Beach and West Niakuk
(4) Meltwater, Tabasco, Tarn and West Sak
(5) Includes Sag River and Schrader Bluff
(6) Includes Badami, Eider and Sag Delta
(7) Includes Qannik
(8) Fiord, Fiord-Kuparuk, and Fiord West
(9) Nanuq and Nanuq-Kuparuk
(10) Includes Alpine West NPR-A
(11) Known Offshore includes Nikaitchuq and Oooguruk
(12) Includes OCS production.

as rumored, then it's possible (see On Deadline).

And trying to keep production flat is not just about state revenues; it's also about the trans-Alaska pipeline tariff for non-TAPS owners, such as Repsol, Brooks Range Petroleum, Linc, Great Bear and others. The tariff will undoubtedly go up as the cost of the system is shared among fewer and fewer barrels of oil, another disincentive for non-TAPS owners to produce oil on the North Slope.

And if TAPS operator Alyeska Pipeline Service Co.'s low flow impact study is correct (see story on page 23), there is a whole list of mitigation measures that Alyeska will have to implement to keep the pipeline operating as throughput drops below 600,000 barrels a day — costly mitigations that could also raise the tariff.

BP, ConocoPhillips and ExxonMobil own the largest percentages of TAPS, so a higher tariff is not going to sour them on Alaska, as a pumped up tariff has in the past with several oil companies, including Conoco before it merged with Phillips, which in turn purchased the assets of ARCO Alaska.

Repsol hoping for 119,000 bpd

So, excluding Great Bear's potential production, let's look at possible production in the next 10 years from other explorers, starting with Repsol, which has about 20 prospects on just under 500,000 acres that were identified by minority partners Armstrong Oil & Gas's North Slope subsidiary 70 & 148 and GMT Exploration.

Oil production from Repsol's first five exploration projects is scheduled to come online between 2015 and 2018, peaking at 119,000 barrels a day in 2017 or 2018.

The company appears to be drilling its low-to-moderate risk prospects first, although one of the initial five drilling sites was switched out for another where several leases are set to expire.

If the company is only able to permit and drill four of those projects this winter, it is likely to drill the prospect it dropped next winter, along with several others, delaying one project's production by a year.

Armstrong expects changes in ACES

With at least 119,000 barrels a day in the pipe by 2018 or 2019, it appears Repsol will nearly singlehandedly save the day for Alaska.

But what wasn't said in Repsol's March 7 press release announcing its deal with Armstrong and GMT was a single word about ACES, although the company did say one of the reasons it entered into the $768 million transaction is because the Parnell administration is looking at ways to make the state more for attractive for oil and gas investment versus trying to squeeze more tax dollars from industry.

Just three weeks before the long-awaited deal closed Armstrong Vice President Ed Kerr submitted a letter to the co-chairs of the Alaska Legislature's House Resources Committee, saying that the governor's bill, "HB 110 will have a significant impact on our capital expenditures and future activities in Alaska. The improved fiscal terms as proposed by HB 110, particularly the portions of the bill that apply to activities outside of existing units, will give us the needed incentive to not only drill multiple new wildcat and delineation wells, but the motivation to drive certain projects to development."

Kerr said Armstrong has "more than a dozen ideas outside of existing producing units" on its project list, ideas it hopes to drill and test.

"In many cases we know the oil is in place. The improved fiscal

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Four years of stability

Long-term outlook will depend on Western energy policies and global political unrest

By ROSE RAGSDALE
For Petroleum News

The volatility of recent years might suggest that all bets are off when it comes to oil prices in the medium and distant future. But the next three to four years could provide the world with a much-needed respite from the rollercoaster ride that transported crude prices to an all-time high of $147 per barrel in July 2008 before plunging them in a free fall to nearly $30 a barrel in December of that same year.

Since then, prices have rollicked along with far less dramatic hiccups. Light, sweet crude is currently trading near $100 a barrel, and analysts have noted a price increase by nearly a third between mid-October and mid-November.

Another bumpy ride?


JUDY PATRICK
ROGER **HERRERA**

Are we headed for another bumpy ride in which some forecasters have already predicted that prices could climb as high as $200 a barrel in 2012 if a host of major world events converge?

The economic, political and technological forces that have always driven oil prices will continue to do so in the future, but with a difference, longtime oil industry analyst Roger A. Herrera told Petroleum News Nov. 28.

"In 2008 the first recent economic recession, I could argue, was triggered by the high price of oil. It was affecting everything we were doing," Herrera said. "However, today oil is a follower, not a leader. That was forcefully demonstrated during the battle in Libya a few months ago when 1 billion barrels per day of oil production effectively dried up and there was virtually no effect on world oil prices."

Herrera, who shared his latest analysis of the various forces that will affect petroleum prices in the New Year and beyond, has spent more than 40 years observing oil prices.

He started his career as a petroleum industry geologist in Alaska, and then worked around the world, in places such as Peru, East and West Africa, Greece, Canada's Arctic Islands, Colombia, Papua-New Guinea, Libya and Barbados before returning to Alaska in 1975, where he became increasingly involved in the federal politics of oil production in the northernmost state.

Herrera spent a lot of time in Washington, D.C., on issues such as offshore exploration and opening the 1002 area of the Arctic National Wildlife Refuge to energy exploration.

From time to time during the past decade and a half, Herrera has been interviewed by Petroleum News. Each time, he has accurately predicted the direction of oil prices.

Economy, politics will drive prices

He told Petroleum News that he suspects forecasting oil prices today may be "foolhardy," but he would attempt to do so anyway.

Herrera said the future of oil prices rests on what happens with the world's economy, which is currently beleaguered by the European debt crisis and the huge U.S. debt, and with political unrest in the Middle East.

"That won't change in the short term, and one would have to be a very big optimist to think it will change in the long term," he said.

To expect the new governments in Greece, Italy and a number of other, smaller European countries to solve their problems "is naïve" and to solve them in the short term "is even more naïve."

"So I think oil prices will stay at the current level of between $80-$100 per barrel for the foreseeable future," he said.

One caveat

Herrera did add one caveat to his price prediction: Unexpected events in the global political situation.

Iran's nuclear weapons capability, the perennial strife between Sunni and Shiite factions in Iraq or something else could create a new crisis in the Middle East that shuts down the Strait of Hormuz or somehow limits the oil output of Saudi Arabia or other Middle Eastern countries.

"If that happens, oil prices will increase but more importantly, it will increase the depth of world economic problems and prolong our agony into the future," Herrera said.

He also said oil demand from China is unlikely to change this scenario because that country has embarked on huge internal energy schemes to quench its thirst for oil. These include developing its own hydrocarbon resources and new nuclear power facilities when the rest of the world is shunning that energy source.

"China is going to do reasonable things for its own energy needs by other means than decadent use of energy like the West," Herrera said.

Because China has avoided imitating wasteful energy policies of the West, he said the Asian country will have an easier time of meeting its future energy needs.

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A NOTE TO READERS

Oil prices play a role

Oil prices play a role in the attractiveness of Alaska's fiscal regime.

When the current production tax was passed, oil companies were concerned about low oil prices and the impact of ACES on their profits.

Almost no one was looking at the possibility of $100-plus oil.

Petroleum News' favorite oil price guru has always been Roger Herrera. He's always been right, even when world renowned commodity authorities were not.

So once again we asked him to show us the future of oil prices.

—Kay Cashman

STABILITY *continued from page 16*

In 2010, the U.S. and China were responsible for 32 percent of global oil demand, while the 17 countries using the euro accounted for about 12 percent, according to BP Plc's Statistical Review of World Energy released June 8.

Conservation could improve outlook

As for other factors, Herrera said he does not envision oil prices being artificially manipulated in the future, as they have been in the past by OPEC countries. "I just don't see that happening," he said.

"I'd rather say that we will work things out with the economic situation in the next three to four years, and there will be no major crisis in the Middle East. We will return to economic growth and begin to drive up oil prices again," he said. "After four years, higher oil prices will inevitably dampen growth in the world economy, and what happens then will depend on what we've learned in the medium term."

Sensible energy policies, including meaningful conservation measures, could improve the outlook for oil prices.

"If we persist in the excesses that we've indulged in, we will continue to go from the giddy heights to the dismal depths," he said. "If we get out of this depressing economic situation by doing sensible things and then go on to do the same old, wasteful things that we did before, nothing will change."

Herrera said he has given up on waiting for a "magic bullet" that will solve the energy dilemma. "I remember when I was in college years ago and people were talking about putting water into a fuel cell and running a car. Well, it's not going to happen. So just forget it and get on with life and making sensible decisions," he urged.

"If we persist in the excesses that we've indulged in, we will continue to go from the giddy heights to the dismal depths. If we get out of this depressing economic situation by doing sensible things and then go on to do the same old, wasteful things that we did before, nothing will change."

—Roger A. Herrera, oil industry analyst

Energy supply problems ahead

As for the effects of peak oil, Herrera said responsible forecasters believe that global oil production peaked in 2005 and since has rolled along a plateau of relatively minor ups and downs.

"When all these political and economic problems work themselves out, I don't think the energy supply will be present to meet that growth," he said. "There will be nothing to rescue us. Once we get into the growth scenario, oil prices will go up, and they will go higher than $150 per barrel because of inflation."

When asked if oil prices will fall below $80 per barrel for a significant period of time in the future, Herrera said that is not likely.

"I personally don't think so, unless we go into a recession that makes the 1920s look mild," he said. "I just don't see that happening.

"There are no sunny skies ahead. We are in a different energy era. We will see lots of surprises, and they won't be pleasant," added Herrera.

Editor's note: This story was written for Pumping up TAPS, but published in Petroleum News in December 2011.

Tight situation on North Slope

Alaska oil explorers hit the limit on rig availability for winter drilling

By ALAN BAILEY & KAY CASHMAN
Petroleum News, Dec. 4, 2011

The surge in exploration activity planned for Alaska this winter has placed a major strain on the supply of drilling rigs suitable for use in the demanding conditions of a long Arctic winter. At last count four companies with exploration drilling plans — Linc Energy, Savant Alaska, UltraStar Exploration and Great Bear Petroleum — had yet to sign contracts for drilling rig use. And given the relatively small inventory of Arctic rigs it seems highly improbable that all of these companies will end up drilling in the coming months, assuming that companies with rig contracts do in fact proceed with their planned drilling.


FORREST CRANE
DAVE **HEBERT**


FORREST CRANE
RON **WILSON**

Three other companies, Repsol, Brooks Range Petroleum and Pioneer Natural Resources have seven rigs under contract for this coming winter exploration season: Repsol expects to drill 12 wells; Brooks Range, two wells, plus re-enter a third; and Pioneer, two wells.

Nabors operates 12 rigs

On Nov. 29, David Hebert, general manager of Nabors Alaska Drilling, talked to Petroleum News about some of the issues involved in supplying rigs for Arctic Alaska exploration. Nabors currently operates 12 rigs that are suitable for Arctic use and that are in a fully operational status, Hebert said. An additional Nabors rig on the Kenai Peninsula has not been winterized for the Arctic.

Two of the Arctic rigs are workover rigs for in-field use, while another has a design that is not especially suitable for exploration drilling.

Any of the other active rigs could potentially be used for exploration drilling, but three of those rigs are under contract for development drilling in North Slope oil fields during the winter. Another rig is drilling wells for Cook Inlet Natural Gas Storage Alaska's new natural gas storage facility on the Kenai Peninsula.

All six remaining Arctic rigs are already contracted for winter exploration drilling, Hebert said. However, Repsol, a company that has contracted for the use of four Nabors rigs during the winter, has recently informed Nabors that it will not in fact require one of those rigs, thus putting one rig back on the market, he said.

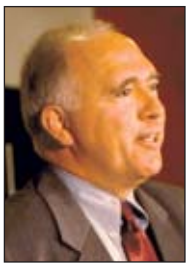
However, specific rigs are only suitable for certain types of exploration drilling

continued on next page

Four-month jobs tough sell

The surge in North Slope exploration activity has produced another problem: convincing experienced rig workers who have left the state for the Bakken shale fields, or elsewhere, to quit their jobs and come back to Alaska for a mere 3-4 months.

Or training new workers but only being able to guarantee them a few months of work a year in one of the harshest environments in the world.



JUDY PATRICK

JIM **WEEKS**

In most regions of the country exploration drilling is allowed year-round, using temporary gravel roads to reach road-less tracts of land.

But temporary gravel roads are rejected by state, federal and borough regulatory agencies in Alaska, which prefer winter ice roads and pads, thus limiting the annual exploration season to 3-4 months.

Jim Weeks, managing member of Alaska independent UltraStar Exploration and former ARCO Alaska executive, recently wrote a letter for an early November special meeting of the House Resource Committee, meeting to hear testimony on impediments to filling the Trans Alaska Pipeline System, or TAPS.

Weeks proposes a change to the current lease form by the Division of Oil and Gas that requires the use of ice roads and pads, saying allowing temporary year-round gravel roads could lower the cost of exploration — and speed up both exploration and development of new fields.

"As it now is, the successful bidder at a lease sale is awarded a contract to explore, develop and extract oil and gas from that lease," Weeks wrote. "The contract stipulates that there will be no exploration on the lease except from approved ice roads and pads, built only when there is sufficient snow cover and frozen depth to carry the heavy loading of drilling rigs and equipment.

"This restricts the exploration drilling window to generally mid-January to no later than about April 15, depending upon the status of the well," he said.

"So there is essentially a 90 day period in which to construct the ice road and pad and move in the rig and associated 50 truckloads of parts, plus camps, shops, generators, fuel storage tanks and other supporting facilities," restricting the number of wells that can be drilled each year.

"Companies like Repsol, with nearly 400,000 acres to explore and delineate, will require multiple years to prove up commercial reserves and make plans for development. So it will need to re-build the needed ice roads and pads multiple times before development decisions are made. Linc Energy faces a similar challenge at Umiat," Weeks said.

"The state should let private industry decide the most efficient and lowest cost manner to conduct exploration," he said. "Ice roads and pads may be the best way forward for close in exploration. But for access to locations further from the road system, re-building ice roads every year for several years gets pretty expensive."

If existing, or newly constructed permanent or semi-permanent gravel roads, airstrips and drilling pads would be more cost effective, they should be allowed, Weeks said.

Year-round access to leases being explored would shorten the time to production by years, he said.

"The ability to drill throughout the year will also significantly shave the winter peaking demand for drilling equipment, materials and manpower, thereby further reducing costs," for the operators.

"An all-weather road to the location of the drilling also provides year round access for emergency response equipment and personnel, adding another level of safety to the already very high operating standards for humans and the environment," Weeks said.

—Kay Cashman

RIG AVAILABILITY *continued from page 19*

project — the question of whether a particular rig is available for a particular project will depend on both the design of the rig and the nature of the project, he explained.

"It requires matching a certain rig to a certain type of location."

Nabors has three rig types

In particular, the weight and means of transportation of a rig impacts the type of drilling site that a rig can reach, Hebert said.

Essentially, Nabors operates three rig types: large wheeled, self-propelled rigs that can traverse ice roads but that cannot cross ice bridges over waterways; truck-pulled rigs that require ice roads but can cross a heavy-duty ice bridge; and modular rigs that can be broken down into truck loads for transportation to remote sites, crossing floating ice bridges en route if necessary.

Nabors has an additional wheeled, self-propelled rig that is currently mothballed and would require at least two months of work to bring back into service, Hebert said, adding that Nabors is not in an immediate position to activate that rig, given the company's current workload.

A second mothballed rig requires substantial refurbishment involving quite a few months of work, he said. And, although Nabors has other mothballed rigs in Alaska, these rigs require major refurbishment, involving many millions of dollars in expense. Given the substantial cost and time required to bring any of these rigs into operation, an exploration company would have to make a firm commitment for rig use well in advance of a drilling operation, Hebert said.

"That would take some sizable commitment on someone's part," he said. "That would not be something that most (drilling) contractors would speculate on."

Winterization has to be done correctly

Another way of increasing the size of the active Alaska drilling rig fleet would be to bring rigs from Canada or from the Lower 48. However, winterizing a rig for use in northern Alaska's extreme climate is a major exercise, involving significant cost and time, Hebert cautioned.

"It can be done, but it has to be done correctly," he said.

Rig winterization involves attention to many details — for example, electrical wiring and hydraulic hosing needs to be Arctic rated, especially given the likelihood of having to transport an unheated rig over a lengthy ice road in extreme cold before a

drilling operation starts. Even rigs from Canada require customization for Alaska conditions, Hebert said.

Again, a firm contractual commitment well in advance of when a rig is needed would be essential to embarking on a rig winterization project. And the rig market outside Alaska is tight, potentially making rig acquisition difficult.

Bringing in new rigs is also an option.

Three and a half years ago Nabors delivered the first purpose-built AC rigs for the North Slope in 13 months, from design to delivery. Two and a half years ago the company delivered CDR-2 to ConocoPhillips at Kuparuk; it was the first purpose-built coiled tubing rig designed for the Arctic. It took 18 months, from design to delivery.

Tax, in-field demand are factors

Another variable in rig availability is the amount of in-field development drilling that is taking place, given that both in-field drilling and exploration drilling draw on the same rig inventory. People are projecting the possibility of even more exploration activity in the 2012-13 winter season, Hebert said. But if BP and ConocoPhillips' field development activity also increases due to the Alaska Legislature passing the governor's bill that reduces the state's production tax, rig availability in 2012-13 would pose an even bigger challenge than at present.

"We could easily run out of rigs again next winter," Hebert said. And some of the Nabors rigs currently under contract for exploration are especially suitable for use on North Slope oilfield well pads, thus making these rigs especially desirable for in-field work, he said.

There is time to refurbish mothballed rigs for next winter, but Nabors would need that up-front commitment for rig use before bringing a rig out of hibernation, he said.

Seven Doyon rigs

Ron Wilson, general manager of Doyon Drilling, told Petroleum News Nov. 30 that Doyon has seven active drilling rigs in Alaska.

Six of those rigs are under contract to North Slope oilfield operators for the coming winter and the other rig, the Arctic Fox, is under contract to Repsol for exploration drilling.

The Arctic Fox is a lightweight rig that can be trucked almost anywhere, he said.

Doyon used to own another lightweight exploration rig, the Arctic Wolf, but that rig is now in Canada; it is owned by Akita Drilling and has been disassembled, Wilson said.

One of the Doyon rigs under contract

continued on next page

A NOTE TO READERS

One more challenge

Explorers are facing a tough situation on the North Slope; one that promises to carry into 2013 and beyond.

There are almost as many wells planned for the upcoming North Slope winter exploration season than the record of 33 that were drilled in 1969, following the discovery of the giant Prudhoe Bay oil field.

Initially, there were 34 wells planned for 2011-12, but a shortage of drilling rigs and crews put an end to that. At least two explorers will have to postpone their drilling plans until next winter.

—Kay Cashman

RIG AVAILABILITY *continued from page 21*

for in-field work has proved especially successful in the past for exploration drilling, although any of Doyon's rigs could potentially be used for exploration, depending on whether the transportation route to the drilling site can accommodate the rig's weight, Wilson said.

Build rather than convert

Wilson said that, given the tight rig supply situation in the Lower 48 and the work required to modify a rig for Arctic use, it could prove simpler to build a new rig rather than convert an existing rig, should additional rigs be needed in Alaska.

However, rig construction might take 16 to 18 months and the construction cost would raise the issue of how much a company like Doyon would be willing to invest on speculation, Wilson said. The investment risk would best be managed by linking rig construction to a specific drilling project, he said.

Wilson also commented on the difficulties that Doyon experienced a few years ago when trying to use a Canadian rig for Arctic Alaska exploration. Severe cold spells in Alaska seem to last longer than in the areas of Canada where Canadian rigs operate, and northern Alaska can also experience challenging wind conditions, he said.

Kuukpik's 3 rigs drilling in fields

Kuukpik Drilling has an Arctic-equipped drilling rig, suitable for exploration drilling and based in Alaska. However, that rig is

JUDY PATRICK

The Arctic Fox rig

under contract for the entire winter of 2011-12, doing gas well drilling in the Barrow gas fields, at the extreme western end of the North Slope.

Kuukpik anticipates its rig being available for drilling on other projects in the winter of 2012-13, Randy Hicks, general manager of Kuukpik, told Petroleum News on Nov. 28.

Nordic-Calista Services has three drilling rigs in operation on the North Slope. Although one of these rigs was used in an exploration project a few years ago, all of the rigs are currently under contract for in-field drilling and are likely to remain in that situation for the foreseeable future, Udo Cassee, Nordic-Calista's operations superintendent, has told Petroleum News.

DECLINE *continued from page 15*

terms as provided in HB 110 will greatly affect whether these projects will get developed."

Presumably the bigger finds will have the best rate of return, so they would get developed under ACES as it is today.

Pioneer's Nuna Development

Also not included in Revenue's spring 2011 forecast was Pioneer's Nuna Development within the newly expanded Oooguruk unit. Its primary target is the Torok formation (see page 41).

Original oil in place is estimated to be 340 million barrels in the Oooguruk offshore drill site area and the core area of the unit — the planned initial development area where the Oooguruk-Torok reservoir is completely filled with oil. That oil would be included in Revenue's projections.

In the prospective Nuna area, the Oooguruk-Torok reservoir appears to be only partially filled with oil; the original oil in place is estimated at 690 million barrels. Pioneer estimates that it can produce up to 25 percent of that through primary and secondary recovery methods, for a net 173 million barrels.

The Alaska Oil and Gas Commission, looking at primary recovery of 20 percent, or 138 million barrels, says the production rate for the Oooguruk-Torok oil pool over an expected 20-30 year project life is expected to average 4,000 to 9,000 bpd, with peak production of about 8,000 to 15,000 bpd, plus natural gas.

Production could conceivably start in 2017, so it would have some bearing in the next 10 years.

A lot depends on appraisal and exploration drilling into the Torok this winter and next.

And on the economic competitiveness of the project with Pioneer's oil and gas assets outside Alaska.

At a Feb. 16, 2011, House Resources Committee meeting in Juneau, Ken Sheffield, at the time president of Pioneer in Alaska, said the company supports HB 110. He said Pioneer's challenge is finding the next opportunity to grow its business. The company might have the opportunity to expand its Oooguruk project to produce the Torok accumulation, but a half a billion dollars for Torok would have to compete for funding against other opportunities in the Lower 48 in fiscal regimes where the tax burden is not so high.

So, another question mark.

If BP and ConocoPhillips elect not to increase investment and all the stars align for Repsol, the Madrid-based major stands to produce the most new oil from the North Slope in the next 10 years.

Armfield's plan 2050

But there is one other explorer whose production could make a dent in arresting the decline, and that's Brooks Range Petroleum Corp. An active explorer on the North Slope (see page 40), BRPC has drilled five wells and several sidetracks since 2007. It tends to target known, but untapped, fields between 25 million and 50 million barrels close to infrastructure.

Again if all the stars align, it might have two or three fields online in the next 10 years, producing between 5,000 and 12,000 barrels each (numbers not confirmed by BRPC).

In February testimony to House Resources in favor of HB 110, Bart Armfield, vice president of operations for BRPC, talked about his "plan 2050," which takes an incremental look at what would be required to keep the trans-Alaska oil pipeline flowing at 600,000

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TAPS headed for trouble

Two-year, $10 million flow study outlines challenges of keeping oil flowing south

By ALAN BAILEY & KAY CASHMAN
Petroleum News

People have understood for some time that action will be needed to deal with various issues arising from the gradually slowing flow of oil through the 800-mile trans-Alaska oil pipeline, as production declines from Alaska's North Slope oil fields.

But a report published on June 15, 2011, by pipeline operator Alyeska Pipeline Service Co. brings into sharp focus the nature of the challenges involved in keeping oil flowing south to market from northern Alaska, and the steps required to head off major operational problems on the line, which has been operating for 34 years.


TOM **BARRETT**

Mitigation needed

Problems may start arising at flow rates below 600,000 barrels per day, with low-flow mitigation measures being essential to maintain reliable pipeline operation below about 550,000 bpd, the report says.

The report, which is the result of a $10 million, two-year, low-flow study, makes various recommendations for possible mitigation measures but says that it has not addressed the problems that would likely arise at flow rates below 350,000 bpd, thus presumably making this throughput level a current lower limit for practical pipeline operation.

"The study findings make it clear that the technical challenges compound and increase as throughput declines," Alyeska President Tom Barrett said in announcing the results of the study. "The simplest, most direct and cost effective path to dealing with these challenges is to stop the decline by adding more oil."

Throughput in the Trans-Alaska Pipeline System, or TAPS, peaked in the 1980s at 2.1 million bpd and is currently taking in about 625,000 bpd at Pump Station 1 in the North Slope's Prudhoe Bay oil field.

According to the Alaska Department of Revenue's spring 2011 forecast, northern Alaska will be producing only 530,000 bpd in 2020, but in a more recent Revenue forecast due to be released after this part of Pumping up TAPS goes to press, production is rumored to be closer to 486,000 bpd in 2020, and 458,000 bpd in 2021 (check out the On Deadline section on pages 8 and 9 of this issue to find out for sure).

Because of maintenance on the line, on more than a dozen days in the last half of May 2011, throughput dropped below 600,000 bpd.

Water separation likely

Essentially, oil cools as it travels south from Prudhoe Bay, especially during the winter, albeit with a boost to temperatures when unused fluids from the North Pole refinery enter the line at around the halfway point to the Valdez Marine Terminal.

A NOTE TO READERS

Challenged under 600,000 barrels

In addition to the problem of fewer barrels to bear the cost of running Trans Alaska Pipeline System, an investment disincentive to non-TAPS owners, there are the technical challenges of keeping the 800-mile pipeline up and running when throughput drops under 600,000 barrels.

The Alaska Department of Revenue predicted average daily northern Alaska production would be 605,000 barrels in 2011. It looks like it might be a little less, in part because of planned AND unplanned maintenance shutdowns.

—Kay Cashman

As the oil flow slows, the oil becomes progressively colder before it reaches North Pole or Valdez — 110 degrees at Pump Station 1 and, depending on the ambient temperature, about 40 degrees when it reaches the terminus of the pipeline.

If the oil cools excessively, water will separate from the oil and form ice inside the line. Slowing oil flow will also increase the tendency for sludge, otherwise suspended in the oil, to drop out. Line-clogging wax will also increasingly tend to separate from the oil at lower temperatures.

Water suspended in the oil as small droplets will start separating out to form a flowing layer at the bottom of the pipe when the flow rate drops below about 500,000 bpd, the report says.

Engineering analysis and tests indicate that when this drop out happens the remaining water is very likely to freeze, potentially disabling check valves and causing ice accumulations at certain points in the pipeline system, including pipeline bends and inside pipeline valve bodies. The dropping out of water also increases the potential for pipeline corrosion, the report says.

Wax build-up increasing

Wax deposition already occurs in the line, but at lower flow rates the settlement of wax particles inside the line will exacerbate problems associated with wax clogging. The buildup of wax will present problems with the operation of pigs, the torpedo-shaped devices that scrape clean the pipeline interior. Pig operation will become particularly problematic at flow rates below 350,000 bpd, as the differential fluid pressure that drives a pig down the line drops, the report says.

And if the temperature of the oil in the line drops below the freezing point of water, the soil surrounding buried portions of the pipeline could freeze, causing movement of the line as a result of frost heaves. Unless the oil is heated, this problem is likely to start occurring at a flow rate of 350,000 bpd, with unacceptable pipeline displacements and overstressing occurring at 300,000 bpd, the report says.

continued on next page

TAPS TROUBLE *continued from page 23*

The slowing flow of oil may also reduce the efficiency of the pipeline leak detection system, with the possibility of leak detection capabilities dropping below regulatory requirements, the report says.

The formation of ice in the line during any pipeline shutdown during the winter poses particular risks for the system. And any interruption to the operation of the oil refinery at North Pole would significantly increase the cooling of the oil in the southern portion of the line, causing the freezing of water in the line at flow rates below 780,000 barrels per day unless the oil is artificially heated, the report says.

Risk of shutdowns

Barrett said it isn't the risk of leaking oil, but the risk "that we will be shut down more to address these problems."

Because of wax due to lower flow, Alyeska runs more pigs to get the wax out.

Alyeska had a shutdown in January and "part of the startup issue is we had pigs in the line," and when you start up after a length of time, you push wax and ice, whatever is in the line, "towards your strainers and your pumps. And if you take out a mainline pump with that type of stuff you're going to be down … for a long while," he said.

So you run more pigs to address the wax issue, "solving one problem and increasing the risk on the other side."

"Figuring that out, whether we're adding launchers-receivers, or just the type of pigs we run, is complex — it's complicated petroleum pipeline engineering. You have people that can do it, but it is a challenge," Barrett said.

Mitigation measures

The two-year low-flow report presents a shopping list of mitigation measures that could potentially be implemented to keep the pipeline operating at flow rates down to 350,000 bpd.

These measures include the heating of the oil at points upstream of locations subject to particularly low oil temperatures (see sidebar); introducing contingency measures and equipment for handling ice; reducing the amount of water allowed in oil accepted into the pipeline; enhancing the insulation of the pipeline at certain critical points; the injection of corrosion inhibitors and biocides into the oil; installing additional pig launching points in the line; and implementing a new pig technology development program for addressing water and wax issues.

Increasing the flow

If you increase the flow to the million-barrels-a-day target set

continued on page 38

Alyeska to mount operation to heat crude

The operator of the trans-Alaska oil pipeline plans a project this winter to heat up the crude by recirculating it through one of the pump stations.

It's part of efforts to deal with issues arising from declining throughput on the pipeline, which carries North Slope oil 800 miles to the Valdez tanker port.

Because less oil is entering the pipeline as field production wanes, the oil is taking longer to travel to the other end. As a result, oil that enters the line at around 110 degrees Fahrenheit is cooling excessively, inviting problems such as water freeze-ups in the line, greater wax buildup, and frost heaves stressing buried sections of pipe.

For the upcoming winter, Alyeska Pipeline Service Co. plans to "perform enhanced recirculation of crude oil passing through Pump Station 7," company spokeswoman Katie Pesznecker told Petroleum News in an Oct. 6 email.

"We will begin recirculation this month (October) and continue through the winter," the email said. "Recirculation adds heat to the crude oil by passing a portion of the oil through pumps twice: It enters at one temperature, gains heat, then passes through the pump again, exiting at a higher temperature. This will improve our thermal profile going into the colder winter months."

—Abbreviated reprint from the Oct. 23, 2011, issue of Petroleum News, by Wesley Loy

DECLINE *continued from page 22*

bpd through that time.

It's a phased approach, he said, requiring the cooperation of the state, majors and independents.

If 10 new fields averaging 12,000 bpd are brought on in the next 12 years, that would increase recoverable reserves by half a billion barrels, and require in excess of $6.3 billion in investment.

"History demonstrates that we can" do this, Armfield said, based on what has occurred over the last 12 years with Alpine, Northstar, Oooguruk and Nikaitchuq coming online and Badami restarted.

That isn't 10 fields, he said, "but collectively they represent the equivalent of 10, 12,000-barrel-of-oil-per-day field projects."

To get to the next level, 20 years out, requires 22 more fields be brought online.

Armfield said unconventional resource plays and technology developments in the Lower 48 demonstrate what can happen, and said that in the very near future that may be applicable to the North Slope.

By the end of the day, in "plan 2050," 44 new developments have occurred, requiring more than $18 billion in new investment.

Armfield said the new fields are a combination of developments within existing units and grassroots developments. In the first 12-year phase, if existing units supported four new developments "then new players would support six grassroots developments."

But the $18 billion to bring on that much new development really requires $36 billion in investment, Armfield said, because "not every project is going to be successful on the North Slope." He said he used the 50-50 rule, with half failures and half successes, "which is probably very aggressive."

If 10 new fields averaging 12,000 bpd are brought on in the next 12 years, that would increase recoverable reserves by half a billion barrels, and require in excess of $6.3 billion in investment. To get to the next level, 20 years out, requires 22 more fields be brought online. —from Bart Armfield's 2050 plan to keep TAPS flow at 600,000 bpd

To get $36 billion of new investment capital coming into the state requires "the positive adjustment through HB 110," Armfield said.

Other companies agree with BP, Conoco

The questions posed at the beginning of this article were, Can the decline be halted? And since BP and ConocoPhillips operate 98 percent of northern Alaska oil production, can it be done without them?

Maybe. If most of the companies exploring, or set to explore this winter, on the North Slope are successful, there might be enough production to halt the decline in the next 10 years, especially if I'm right about Revenue's fall forecast, so compare the numbers on page 14 with those in the page 8 On Deadline article about Revenue's fall forecast, which came out after all but those pages went to press.

But, the next question is, will those explorers develop their discoveries under ACES?

Not all of them have answered that question.

But they have all said they need HB 110 to make producing oil in Alaska competitive with investments elsewhere.

Pumping up TAPS to 1M barrels

Alaska governor challenges, assists ANS producers, explorers to meet goal in 10 years

By KAY CASHMAN
Petroleum News

On March 30, 2011, Alaska Gov. Sean Parnell announced his administration's goal to increase the flow of oil through the Trans-Alaska Pipeline System, or TAPS, to 1 million barrels per day in a 10-year period.

According to his plan, "Secure Alaska's Future - Oil," reaching this northern Alaska oil production goal would require billions of dollars in private investment, strategic planning by the State of Alaska and coordination with key stakeholders, including the federal government, landowners and energy companies.

Nearly the entire Parnell administration would play a part in implementing the plan, but the leader of the effort would be Dan Sullivan, commissioner of the Alaska Department of Natural Resources, who was key in drafting the five-point plan.

GOV. SEAN **PARNELL**

The challenge

Alaska's North Slope is a world-class hydrocarbon basin that boasts massive quantities of untapped oil and gas, but the governor's comprehensive strategy to reverse the declining flow of oil through the trans-Alaska pipeline was not a small undertaking.

SHANE LASLEY

DAN **SULLIVAN**

Average daily production in the line was expected to be 605,000 barrels a day in 2011, declining at a rate of about 6 percent per year.

In other words, despite these vast resources, production from existing North Slope fields was declining at a much faster rate than it was being replaced.

According to the state's website for the plan, http://1.usa.gov/uAYcxU, the declining flow of oil posed a direct threat to the pipeline: it was becoming more expensive to maintain and the risk of damage from corrosion was increasing. The best way to avoid a premature shutdown of the line was to boost the flow of oil by tapping those vast North Slope resources.

What's at stake

A premature TAPS shutdown would cut off the major source of state revenue that funds education, roads and other vital public services in Alaska, the website said. In addition, it would eliminate one of the nation's top domestic energy assets and increase the nation's reliance on foreign oil.

In January 2011 Sullivan "saw firsthand the perils of the pipeline operating at low throughput."

In a June 4 guest editorial in the Anchorage Daily News, he wrote, "Due to a small leak, the 800-mile line was shut down in the dead of winter. After five long days of around-the-clock activity, it was uncertain if we would get the line up and running again. New to DNR, I had many questions: What if the line is down for another month, four months, or frozen until the summer? Could we shut in all North Slope production and restart it months later? We were staring into an abyss with no easy answers," he wrote.

"We run an increased risk of seeing more episodes like the January shutdown. While maintenance and engineering fixes will help reduce risks, the best way to avoid a premature shutdown of TAPS is to increase oil production. Given the lag of several years between investment and new production, the time to act is now," Sullivan said in the editorial.

Five-point strategy

The Parnell administration's Secure Alaska's Future - Oil strategy had five parts, which Sullivan told Petroleum News in November, had been, and continued to be, "relentlessly" implemented.

"We didn't put this plan together and sit. It's ambitious, but laying out an ambitious plan challenges people," he said.

The goal of 1 million barrels in 10 years is "achievable," he said, given the billions of barrels of oil that remain on the North Slope.

The five parts of the governor's comprehensive plan are:

1. Enhancing Alaska's global competitiveness and investment climate.
2. Ensuring that the permitting process is structured and efficient to accelerate resource development.
3. Facilitating and incentivizing the next phases of North Slope development.
4. Unlocking Alaska's full resource development potential by promoting constructive partnerships between the state and key stakeholders.
5. Promoting Alaska's resources and positive investment climate to world markets.

Cornerstone: Tax reform

A cornerstone of the strategy was the governor's "tax reform" plan to increase industry investment by enacting fiscal modifications to increase Alaska's global competitiveness.

The specifics of that reform included restructuring the state's tax regime for existing units to reduce marginal tax rates at higher prices by capping overall production taxes at 50 percent, and further incentivizing exploration and development in areas outside of existing units by capping overall production taxes at 40 percent for the new units.

The governor's tax reform was embodied in House Bill 110 and passed the state House during its first regular session of the current two-year legislative term. Its companion bill in the Senate, SB 49, did not pass during the first session, but is expected to be the major focus of that body in January 2012, when the Legislature convenes for its second session.

The Parnell administration continued to advocate for passage of the legislation between sessions.

Part one of the plan, enhancing Alaska's global competitive-

ness and investment climate, also included reviewing and considering royalty modification applications for marginal fields, as well as improving infrastructure access and lower cost structure for resource development to more rapidly bring new production to the market.

The Roads to Resources program was part of improving access and lowering costs for development, and included building a year-round gravel road to Umiat.

More efficient permitting

In part two of the plan — ensuring that the permitting process is structured and efficient to accelerate resource development — the administration, with Sullivan in the lead, set about making immediate improvements to the review and process for incoming land and water use applications, eliminating much of the permitting backlog in far less time than the three years allotted in the plan.

Additional employees were added to DNR's Division of Mining, Land and Water to expedite permitting review and processing.

Another key element of part two of the plan was to reduce permitting costs for industry by streamlining the permitting process on all levels — local, state and federal.

Recommending a comprehensive suite of regulatory and statutory reforms designed to provide regulatory certainty, timeliness, and clarity was also part of the strategy.

A high-level permitting task force has begun work on those recommendations.

Push for new oil

Part three of the plan called for facilitating and incentivizing the next phase of North Slope oil development, with "North Slope" meaning everything north of the Brooks Range including:

- Federal OCS resources.
- Federal onshore resources: NPR-A and ANWR 1002 area.
- Unconventional resources: heavy, viscous and shale oil.
- Smaller pools of conventional oil.

The effort to unlock more unconventional resources included forming a Shale Oil Task Force, which is looking at infrastructure, permitting reform, water use and gravel needs.

Promoting partnerships

Part four of the plan, promoting constructive partnerships, had four components.

First, establish "Secure Alaska's Future" council to ensure continued partnership and coordination among stakeholders.

Two, increase congressional and national support for Alaska oil development.

Three, seek detailed planning and coordination with the federal government to increase energy development and enhance U.S. national and energy security.

Four, where federal partnership with Alaska is rejected, continue to vigorously advocate the state's interests to ensure responsible resource development.

"To increase oil production, we need all stakeholders on board," Sullivan wrote in the June 4 editorial. "We are establishing the Secure Alaska's Future council of senior leaders from industry, state government and other entities. The council will meet on a regular basis to generate ideas, pre-empt problems

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Fastest source: legacy fields

BP, Conoco operated oil fields have 4.2 billion barrels of oil left in producing units

By KAY CASHMAN
Petroleum News

There are approximately 4.2 billion barrels of recoverable oil in northern Alaska's legacy fields — specifically those fields that are currently producing oil *and* operated by BP and ConocoPhillips.

Fields operated by those two companies represent about 98 percent of all current oil production from the North Slope. (For simplicity's sake, in this article the "North Slope" includes all oil fields north of the Brooks Range in Alaska, including offshore pools.)

Heavy oil and oil from source rocks is not in included in the 4.2 billion barrels, but some lighter viscous oil, already in production, is included with conventional crude.

A 4.2 billion barrel field qualifies as a super-giant by world standards, and would be the second largest field in Alaska.

The number came from remaining recoverable oil reserves based on the sum of Alaska Department Revenue forecasted production from 2010 through 2050 — based on year-end 2006 reporting, which is bound to be more accurate than forecasts from later years because it reflects very few of the cutbacks BP and ConocoPhillips have made as a result of Alaska's production tax.

It also does not include Badami, which was operated by BP in 2007 but in warm shut down. Today Badami is operated by Savant. Nor does it include any Alpine West oil from the National Petroleum Reserve-Alaska, because the State of Alaska has very little control as to when that oil can be accessed. It does include Northstar because it's in production, but excludes Liberty because it is not in production — and is in federal waters.

Because the legacy operators and their partners invested in technologies such as horizontal drilling, miscible gas injection and gas cap water injection their recovery rates at Prudhoe, Kuparuk, Alpine and others fields are between 50 and 60 percent, as compared to a 35 percent average worldwide.

With continued investments in new technology, that percentage can only rise.

But continued investment — i.e. increasing amounts of oil in the trans-Alaska oil pipeline — the two companies say, will not happen from their fields without passage of Gov. Sean Parnell's legislation to reform the state's production tax. (House Bill 110 passed the House not the Senate; SB 49 will be up for discussion when the Alaska Legislature convenes in January).

More important, enough of the 4.2 billion barrels can be quickly drilled and put in the pipeline to level out North Slope production — probably before explorers Repsol, Brooks Range Petroleum, UltraStar and ASRC Energy can get most of their fields online.

Also to be considered is the fact that not all the explorers will find fields which justify standalone production facilities: Some will need to get BP or ConocoPhillips to allow them to use existing facilities in legacy fields.

Or perhaps truckable/portable production skids, which are being considered by several companies, will work, along with new production facilities that can be shared.

Observations, arguments, promises

Let's look at some of the observations, arguments and promises BP and ConocoPhillips' executives have made in the last two years:

• Alaska's current oil tax system is the biggest impediment to getting more oil into the trans-Alaska oil pipeline — Trond-Erik Johansen, president of ConocoPhillips Alaska, and Claire Fitzpatrick, chief financial officer for the Alaska region and senior vice president of BP Exploration (Alaska).

• The "easy oil" has been drilled. The sweet spots were drilled when the fields were developed — when you put them online, they produced a lot of oil. There is a lot of light oil left on the North Slope, but it's not as easily accessible. And while early water production was low, 3 million barrels a day of water are now being produced: "We're more a water production company than an oil production company," and that water has to be managed. —Johansen

• In many parts of the Prudhoe Bay field liquids production is constrained by the volume of gas being produced. Gas partial processing would remove a production bottleneck so that more oil could be produced. I Pad and a gas partial processing project represent an investment of about $2 billion; investments BP will not make without the tax breaks in HB 110. —John Minge, president of BP Exploration (Alaska) Inc.

• Some of the investments BP has held off sanctioning in its fields have had enough work done on them that they are ready for consideration when the investment climate becomes more competitive. Among those are I Pad development at Prudhoe Bay; western region development at Prudhoe; S pad expansion with low salinity water flooding; and Sag River reservoir development at Milne Point. If those projects had moved forward over the past four years, the projected 25 percent decline between 2011 and 2020 "would be essentially flat." —Fitzpatrick

• Using inflation-adjusted figures, relative drilling costs in the early wells in Kuparuk, West Sak and Tarn cost about $2-4 million a well and took about 10 to 15 days to drill. Today it costs four times as much and it takes four times as long, because wells are no longer vertical or near vertical, but are horizontal. And those wells produce less. —Johansen

• There will be "significant investments in infrastructure and pipeline upgrades," but capital spending on activities that produce more oil, such as drilling and pad expansion, are "limited or on hold" without tax changes. —Fitzpatrick

• Production has dropped more than 140,000 barrels per day since ACES passed. —Fitzpatrick

• I Pad alone will result in drilling some 50 new wells to access about 80 million barrels of additional reserves. That is … like finding another small oilfield. BP does not lack opportunities in a new fiscal environment. —Minge

• ConocoPhillips is prepared to spend $5 billion over the next three to five years to generate 90,000 barrels per day if the governor's tax bill becomes law. —Jim Mulva, ConocoPhillips chairman and CEO

• In the Lower 48, oil production grew 3 percent from 2003 to 2010; Alaska production declined 36 percent over the same period. —Johansen

• Oil at $50 a barrel in 2008 doesn't compare to similar prices in 2005 because "the fundamental cost of our business has changed." Producing a barrel of oil in the Arctic costs between $25-50 today (early 2010). —former ConocoPhillips Alaska President Jim Bowles

• In previous exploration activities BP identified more than 5 billion barrels of resources. These resources can be unlocked with a competitive fiscal policy. —Minge

• BP recently approved two seismic acquisition programs, one at Milne Point and one at Point McIntyre, "in anticipation that the tax law will change." The seismic will be shot in 2012 and 2013, cost $100 million, and yield "at least 20 to 40 extra wells, if governor's tax bill is passed." —Minge

50 billion barrels on hold

Heavy oil worth the least of North Slope crudes, costs the most to produce

By KAY CASHMAN
Petroleum News

There are 50 billion barrels of heavy oil in the Ugnu and West Sak/Schrader Bluff formations overlying the Kuparuk River and Milne Point fields.

As you move east, the accumulation gets deeper and the environment gets hotter, which typically means the oil is lighter — something between heavy oil and conventional oil. It flows better and is generally referred to as viscous oil.

To the west the accumulation is shallower and the oil is more viscous, colder — closer to permafrost — and the formation is looser and produces more sand.

This shallower portion of the accumulation represents the vast portion of the 50 billion barrels.

As Jim Weeks says in his commentary on page 45, these heavy oil accumulations are "known, drilled, proven resources. There is nothing speculative about them except their technical feasibility and economic viability."

And therein lays the rub: Heavy oil is worth less than all other North Slope crudes AND costs the most to produce.

Both BP and ConocoPhillips have made significant investments over the years to find a way to technically produce heavy oil, and have more recently started evaluating the economics, which were initially thought to be impossible.

An area where BP has been working technology to produce the resource is at its new $100 million heavy oil test facility for the Ugnu, where there are between 12 billion and 20 billion barrels of heavy oil.


JUDY PATRICK

JOHN **MINGE**


JUDY PATRICK

CLAIRE **FITZPATRICK**

Heavy must be diluted with light

Eric West, manager of BP's Alaska renewal team, told Petroleum News in August 2011 that the company's first heavy oil test at the facility had a maximum production rate of 550 net barrels of oil per day.

On the commercial side, he said that heavy oil needs to be diluted with light oil to move down the pipeline. It could be possible to flow the heavy oil by upgrading it in a North Slope refinery or by heating the pipeline, but West said BP does not view those options as commercially feasible.

"Because of that linkage (with light oil), the time to look at heavy oil is now. And in fact the longer we wait to look at it, the more the light oil declines, and at some point we're going to curtail the amount of

continued on page 54

A lot of oil, a little too late

OCS production will likely not get under way for 10 years; 30 billion barrels at stake

By KAY CASHMAN
Petroleum News

If If there was a good chance that production might begin from the federal waters of the outer continental shelf off northern Alaska by 2020 or even 2021, the Arctic OCS would have front and center stage in this magazine because it's the only area open to oil exploration and development on or offshore Alaska where there might be another super-giant oil field like Prudhoe Bay. (The U.S. Geological Survey's mean estimate of undiscovered technically recoverable resources in the Chukchi and Beaufort seas off Alaska is 30 billion barrels of oil equivalent.)


JUDY PATRICK
PETE **SLAIBY**

The kind of money thrown down in the federal Arctic Alaska OCS lease sale in 2008 speaks to the potential of the region. Sale 193 drew a record $2.7 billion in high bids, a total of all bids was $3.4 billion, from six bidders, five of them major international oil companies:

- Shell spent $2.1 billion in high bids for 275 blocks.
- ConocoPhillips had high bids of $506.4 million for 98 tracts.
- Repsol had high bids of $14.4 million on 93 tracts.
- Statoil had $14 million in high bids on 16 tracts.
- Eni Petroleum, which in 2011 started producing oil from its nearshore Beaufort Nikaitchuq oil field, had high bids of $9.3 million on 18 tracts.

But even Shell, the lead company in this generation's efforts to explore the federal waters off northern Alaska, said in late 2011 that if everything goes right from now on, and there are no more permitting and lawsuit-related delays, it does not expect to be producing oil for 10 years in Alaska's OCS.

What are the odds of everything going right?

Approaching $4 billion in expenses

Having purchased a substantial number of Beaufort Sea OCS leases, Shell first planned to drill there in 2007, targeting its Sivulliq prospect on the western side of Camden Bay. But in the face of appeals against the approval of various permits that Shell needed before starting drilling, the company's Beaufort drilling plans have repeatedly been postponed and modified.

Shell has faced similar difficulties in the Chukchi Sea, a remote region with world class hydrocarbon potential which the company has said is its top priority in Alaska. Of the $2.1 billion Shell spent in the 2008 federal lease sale, $1.5 billion went for leases on just one prospect, the Chukchi's Burger prospect, a structure 25 miles in diameter, known to contain a major pool of natural gas and lying about 80 miles offshore the western end of the North

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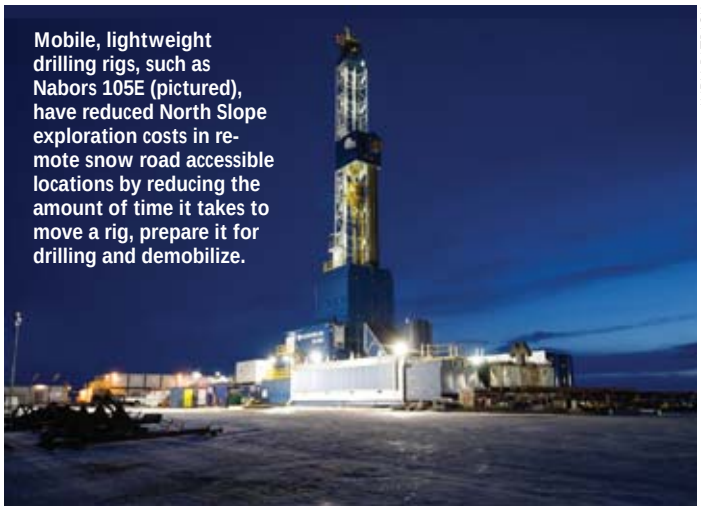

Mobile, lightweight drilling rigs, such as Nabors 105E (pictured), have reduced North Slope exploration costs in remote snow road accessible locations by reducing the amount of time it takes to move a rig, prepare it for drilling and demobilize.

JUDY PATRICK

Billions in untapped crude

On and nearshore the North Slope billions of barrels of oil await discovery

By KAY CASHMAN
Petroleum News

With production from major oil fields in northern Alaska declining, there is a common misconception that the North Slope has become a mature province for conventional oil and gas.

While it's true that most of the larger and easier structural plays, particularly onshore, have been drilled, it's also true that many stratigraphic, and some structural, plays have yet to be discovered or simply delineated, as evidenced by exploration and development activities in the last decade-plus.

Success in the Tarn and Alpine fields in the late 1990s moved exploration attention away from the big Prudhoe Bay-style structures toward stratigraphic traps onshore and nearshore the North Slope. At the same time, BP's Northstar field, largely in state waters and the first Arctic project with a subsea oil pipeline, demonstrated continued success with structural reservoirs.

In general terms, people widely recognize the petroleum systems of northern Alaska as hydrocarbon-rich but reservoir-poor.

So, with an abundance of excellent source rocks and a relative shortage of reservoir-quality rock formations, any isolated stratigraphic trap — a hydrocarbon trap formed by the juxtaposition of reservoir and seal rocks in the rock strata — stands a good chance of containing oil or gas.

Thanks to the use of high-end 3-D seismic techniques to find stratigraphic traps and the use of horizontal drilling to produce from low permeability reservoirs, more North Slope accumulations have become economic to produce.

"Finding new oil with conventional ideas is good (nothing wrong with a nice Sadlerochit play like, say, Northstar)," former Division of Oil and Gas Director Ken Boyd told Petroleum

News in an April 2011 email.

But, he said,"Finding new oil with new ideas is even better. The reason being that new ideas open up new areas to exploration."

For example,"Badami led to all the new exploration just west of Kuparuk.The lease sales we held after the Badami discovery prove that; lots of new leases on old shelf edges, which is where you find turbidites," Boyd said.


KEN **BOYD**

"Same with Alpine.The discovery of the Alpine sand — not a turbidite but a new play — is what enabled me to go to (then DNR Commissioner John) Shively and (then-Gov. Tony) Knowles to push getting NPR-A open again.To their credit they did it, and that was a tough sell during the Clinton administration," Boyd said.

Classic North Slope plays

The classic North Slope oil and gas plays occur along a structural high known as the Barrow Arch under the Beaufort Sea coast of the North Slope.

Essentially there are four major rock sequences in northern Alaska: the Franklinian, the Ellesmerian, the Beaufortian and the Brookian, with the huge Prudhoe Bay oil field situated in the Ellesmerian; the Beaufortian hosting fields such as Kuparuk and Alpine; and the Brookian hosting fields including Badami and Meltwater.

Companies are still looking for opportunities in the Ellesmerian, where there are numerous structural plays.

Huge range of potential sizes

Although some of the Beaufortian sands can be thin and discontinuous, other areas of more continuous sands have given rise to large reservoirs. Basically, you get a huge range of potential sizes in the same rift breakup sequence but there are a lot of plays in the 20 million to 70 million or 80 million barrels size.

"There are still plays in the 300 million, 400 million or 500 million to a billion-plus size — they're still out there, but they're almost all stratigraphic," Mark Myers, former director of Alaska's Division of Oil and Gas and the U.S. Geological Survey, told Petroleum News.

Success with Alpine, the main field in the ConocoPhillips-operated Colville River unit that came online in 2000, and its Beaufortian Jurassic sandstone reservoir, spurred interest in similar Jurassic plays.There is a series of upper Jurassic sands just below the Alpine sands:"There's at least a billion barrels in place, we think, in that trend," Myers said.

Because of the low permeability of the reservoirs in the Alpine play the gravity of the oil really impacts the ease of oil production. And the oil gravity depends on which of the multiple source rocks in the area generated the oil.

"The source rock's critical and often you get multiple source rocks in a given area," Myers said."If you look at the Tarn play on the west side of Kuparuk you've got 38-to-37 API gravity in close proximity of 26-to-22 gravity in Kuparuk, because of changes in the sourcing."

Brookian stratigraphic plays

There is a major Cretaceous and Tertiary sequence of petro-

continued on next page

UNTAPPED CRUDE *continued from page 35*

leum bearing sedimentary rocks above the Ellesmerian and Beaufortian sequences in northern Alaska.

Known as the Brookian sequence, this younger rock sequence extends all the way from the northern edge of the Brooks Range out over the North Slope and across the continental shelves of the Beaufort and Chukchi seas.


MARK **MYERS**

Stratigraphic plays involving topset or turbidite strata in submarine fans typify this Brookian sequence.

"Some of the … submarine fans are very large," Myers said: "If you had reservoir quality and if you had closure you could approach the billion-barrel mark in some these if you had structural fill."

Then there are other situations where you may find smaller fans with as little as 20 million barrels of oil and where several smaller fans stack together the combined volume of oil could reach around 100 million barrels.

However, production problems in the eastern North Slope's Badami field have shown that Brookian plays aren't without risk.

Because the sequence tends to overlie Beaufortian or Ellesmerian rocks, there are opportunities to explore where there is more than one play at the same location, Myers said.

Brookian plays may dominate the coastal plain of the Arctic National Wildlife Refuge's 1002 area, at the eastern end of the North Slope — Myers concurred with a USGS assessment that the Brookian sequence probably contains the preponderance of oil in that area. However, a couple of intriguing structural trends in the northeast of the ANWR 1002 area include potential Kuparuk-style plays.

Headed west into NPR-A

ConocoPhillips and partner Anadarko spearheaded exploration and development west from the Colville River Delta, at the western extremity of existing central North Slope oil infrastructure, into the northeastern part of NPR-A.

A series of wells drilled in the area by the partners since the renewal of leasing in NPR-A in 1999 have tested Alpine-equivalent prospects and have yielded discoveries of light oil, condensate and gas in stratigraphic traps, overlooked before the advent of 3-D seismic imaging.

The accumulations can be viably developed by extending the oil pipeline infrastructure west from the Colville River unit, which contains the first North Slope fields developed exclusively with horizontal well technology.

The unexpectedly prolific sands at Alpine opened the door to extending a new Beaufortian play beyond the Prudhoe-Kuparuk infrastructure. The concept is to progressively move farther and farther west into NPR-A, opening up new oil pools as access to the pipeline infrastructure becomes available.

Chukchi could open western NPR-A

But progress had come to a halt because the U.S. Army Corps of Engineers had refused to permit the construction of an access bridge across the Nigliq Channel of the Colville River, which ConocoPhillips said it needed to develop the NPR-A fields, the first being the Alpine West satellite, from its CD-5

continued on page 38 (sidebar on page 37)

Bright side for NPR-A estimates; prospects could rival, exceed Alpine

A new economic analysis of the National Petroleum Reserve-Alaska, released in May 2011 from the U.S. Geological Survey, estimated there were 986 million barrels of undiscovered, technically recoverable conventional oil in the reserve, down from a 2002 assessment of 10.5 billion barrels.

State of Alaska geologists strongly disagreed with USGS' downgrade.

The revised estimates resulted from data that wasn't available in 2002; data from exploration wells drilled in the past decade, which indicated an abrupt change from oil prone to more gas prone resources just 15 to 20 miles west of the Alpine oil field in the Colville River Delta, USGS scientists said.

Consequently, oil plays analogous to the Alpine field in NPR-A likely contain very little oil west of the area that ConocoPhillips and Anadarko Petroleum have been exploring around their Lookout and Alpine West prospects, USGS said.

Much of the agency's new pessimism over potential NPR-A undiscovered, recoverable oil revolved mainly around a revised evaluation of the petroleum system in the Beaufortian sequence, one of four major oil-bearing rock sequences in northern Alaska.

Greatest potential near Teshekpuk Lake

USGS said the greatest potential in the Beaufortian sequence was near Teshekpuk Lake and the adjacent coastal plain, a region largely inaccessible because of environmental concerns.

And while USGS dropped its oil estimates for the Brookian, the youngest and shallowest of the region's four rock sequences, it also commented that the greatest potential for finding new NPR-A oil exists in what are termed "stratigraphic traps" in that same Brookian sequence.

And while USGS dropped its oil estimates for the Brookian, the youngest and shallowest of the region's four rock sequences, it also commented that the greatest potential for finding new NPR-A oil exists in what are termed "stratigraphic traps" in that same Brookian sequence.

During the May 2011 meeting of the Pacific Section, American Association of Petroleum Geologists, in Anchorage, scientists from the U.S. Department of the Interior, home of USGS, said that it was possible to find huge Brookian stratigraphic traps in northeast NPR-A, in locations ideally positioned to capture oil from prolific oil source rocks at the base of the Brookian.

"These untested prospects potentially rival or exceed the size of the Alpine field discovery 15 years ago," the scientists said.

UNTAPPED CRUDE *continued from page 36*

drilling pad. The objections to the permit had come from U.S. Fish & Wildlife Service and the Environmental Protection Agency.

On Dec. 5, the U.S. Department of the Interior announced the agencies had reached "an agreement in principle" with the company.

ConocoPhillips, Anadarko and others have also explored much farther west in NPR-A, but viable oil and gas development at such large distances from existing oil infrastructure would require a major oil find of at least 1 billion barrels.

If Shell, ConocoPhillips, Statoil and others develop their Chukchi Sea leases 100 miles offshore NPR-A, about 150 miles west of Barrow, a subsea oil pipeline would likely be brought to shore at the village of Wainwright in the remote Northwest Planning Area of NPR-A, and then run through the petroleum reserve and on to Pump Station 1 at the central North Slope's Prudhoe Bay field.

A pipeline across NPR-A would open up the petroleum reserve, making it economically viable to drill a number of the larger accumulations there.

TAPS TROUBLE *continued from page 24*

by the governor, "a lot of these problems fall off from an operating point of view," Barrett said.

He said he believes "we're a couple of years behind."

When Alyeska started its low-flow study in 2008, the projection for 2011 was 700,000 bpd.

"We're seeing 600,000 barrels," Barrett said, adding that he worries that there isn't the urgency needed to get additional barrels into the line.

The resources are there, the infrastructure is there, so what's stopping Alaska from moving a million bpd, he asked.

"Two things: political will … political will in Juneau; political will in Washington."

"I actually think that's the obstacle to turning this dynamic around and allowing us to operate better in the future."

Sea change for BP, Conoco

Back near the core area of the central North Slope, the high-performance Beaufortian reservoir of the ConocoPhillips Palm discovery on the western edge of the Kuparuk field led to the construction of a new drill site and expansion of the Kuparuk River unit in 2003. A number of satellites were also being developed at Prudhoe by unit operator BP.

By 2002, both BP and the newly merged ConocoPhillips, which had picked up ARCO's Alaska assets two years earlier through Phillips, had begun concentrating on finding "new" oil in their legacy assets in the state, such as the Prudhoe, Kuparuk and Colville units.

With the exception of its ANWR 1002 area leases, BP sold or dropped all its exploration leases, starting in 2001.

ConocoPhillips was still exploring, but on federal acreage onshore and offshore, looking for big fields and dropping its state exploration acreage. Over the next decade the company dropped even its Beaufort Sea federal leases and pulled back from wildcat exploration in NPR-A, concentrating on its step-out development of the Colville River unit into NPR-A and pulling more oil out of its existing fields. It looked to its federal leases in the Chukchi Sea for its next giant oil discovery in Alaska.

Drop in TAPS tariff drew investment

This shift in strategy left northern Alaska wide open to independents and majors alike looking for new opportunities in the state, including non-owners in the Trans Alaska Pipeline System because beginning in 2000, the Regulatory Commission of Alaska, and later the Federal Energy Regulatory Commission and the courts, began ruling against a methodology established in a 1986 settlement between TAPS owners — subsidiaries of BP, ConocoPhillips, ExxonMobil, Koch and Unocal (a mere 1.36 percent) — and state and federal regulators that produced tariffs too high for non-owners to be able to economically produce oil in Alaska.

The November 2000 state areawide lease sales for the North Slope and Beaufort Sea saw the first significant bids from independents, including Anadarko and AVCG LLC of Kansas.

BRPC looking to produce

AVCG and its partners eventually formed an operating arm,

continued on page 40

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UNTAPPED CRUDE *continued from page 40*

Brooks Range Petroleum Corp., or BRPC. In the pursuit of fields between 25 million and 50 million barrels, the joint venture drilled five wells and several sidetracks in the last few years, leased more than 330,000 acres in Alaska, and is looking to become one of the most active developers on the North Slope where it has formed five units in the central North Slope, four of which are in the "billion barrel fairway" between the Kuparuk River's western boundary and the Colville River.

From north to south those units are the Southern Miluveach, Kachemach, Tofkat and Putu units.

BRPC's first unit, formed in 2009, was the Beechey Point unit in the Gwydyr Bay region north of Prudhoe Bay.

The unit's onshore and offshore leases, where BRPC has drilled several wells, are long known to overlie several oil deposits considered small, but only by the outsized standards on the North Slope.

BRPC said in agency filings that despite "respectable" results from previous wells in the area by majors, "a cost structure founded on drillsites capable of producing 100,000 bpd was not suitable for 'marginal' areas, particularly with commodity prices in the $20 to $30 price range," and, "as a consequence, these accumulations lay dormant for many years."

On the top end BRPC's partners expect to recover as much as 15 million barrels of oil from the unit.

More wells planned at Mustang

This winter BRPC has committed to the Division of Oil and Gas to complete three wells or sidetracks in its Southern Miluveach unit's Mustang prospect, formerly known as North Tarn.

Brooks Range previously estimated the Kuparuk formation at Mustang could contain 6 million barrels of oil, enough to make the play economic. The company also said North Tarn included a target in the shallower Brookian formation that could hold 35 million barrels, but would be more difficult and costly to produce because of complex geology.

Under the terms of its agreement with the Division of Oil and Gas, working interest owners must decide by Oct. 1, 2012, whether they will sanction Mustang development.

More wells, development decisions

Under the plan of exploration with the division for its Tofkat unit, BRPC must drill and complete a well and sidetrack into the Kuparuk formation by May 31, 2013. The owners must sanction the Tofkat development by Oct. 1, 2013.

Under its agreement with the state for the Putu unit, BRPC must drill four wells into the Upper Jurassic-age strata of the Kingak formation by May 31, 2013, two targeting the Musketeer trend (Brookian Sequence Boundary C) and two targeting the Big Foot trend (Brookian Sequence Boundary BC).

Under the Kachemach unit agreement, BRPC must complete one well in Block A targeting the Caribou trend (Brookian Sequence Boundary F) and one well in Block A targeting the Moonlight trend (TP4-2 Nanushuk prospect) by May 31, 2013.

If BRPC meets those commitments the company must then commit to complete one well in Block B targeting the Moonlight trend (TP4-1 Nanushuk prospect) by May 31, 2014.

UltraStar focused on Dewline

Long-time senior vice president of ARCO Alaska, Jim Weeks, joined newly formed Winstar Petroleum in 2000. Alaska-based Winstar had already acquired 12,000 acres on the North Slope as Petersburg Energy LLC.

Weeks also helped found UltraStar Exploration LLC in 2002. The companies have an overlapping group of investors and leases that are close to infrastructure and processing facilities.

Following Winstar's dry hole at Oliktok Point, UltraStar obtained 3-D seismic over its leases west of BP's Point McIntyre field, which showed several prospects.

Weeks decided to pursue the Dewline Deep prospect, believed to hold between 5-20 million barrels of oil in the Ivishak and Sag River formations.

Following years of negotiations that included talk of possibly expanding the Prudhoe Bay unit to include Dewline Deep, UltraStar and BP came to terms on a framework for access to the drill site and for the future use of Lisburne facilities.

UltraStar drilled the Dewline No. 1 well in early 2009, and is planning a second well this winter, if a rig is available.

And then comes Armstrong

In October 2001, Denver independent Armstrong Oil and Gas bought its first leases in the state's areawide North Slope and Beaufort Sea lease sales, leading to the development of the first independent-operated oil field in northern Alaska, Oooguruk, by its partner Pioneer Natural Resources, and the first processing facilities not operated by BP or ConocoPhillips at the Eni Petroleum-operated Nikaitchuq field. (Oooguruk's crude is processed at the nearby ConocoPhillips-operated Kuparuk River unit.)

Armstrong sold its northern Alaska assets to Eni in 2005, but returned to the North Slope in 2008, doing business through a subsidiary 70 & 148 LLC.

In March 2011, Armstrong and partner GMT Exploration brought in Spanish mega-major Repsol as a 70 percent partner to help explore and develop nearly 500,000 acres on state leases onshore and nearshore.

Repsol paid $768 million for the privilege, with about $750,000, PN sources say, going to be used for exploration, starting with the 2011-12 winter off-road drilling season, when it plans to drill 12 exploration wells from four ice pads.

Initially five pads and 15 wells were planned — one vertical and two laterals per pad, using five drilling rigs — but in consideration of the concerns of local residents the company is expected to pull one of its five applications in mid-December.

Repsol, which has about 20 prospects identified by Armstrong, will likely drill that fifth prospect and several more the following winter of 2012-13; not only is it motivated to bring oil online quickly, but 84 of 157 of the company's state leases are set to expire in 2012, 2013 and 2014.

Oil production from Repsol's first five exploration projects is scheduled to come online between 2015 and 2018, peaking at 119,000 barrels a day in 2017 or 2018.

Given the Parnell administration's reluctance to extend and/or unitize a lease without at least one well from the current leaseholder, it's safe to assume Repsol will be a very active explorer, as well as a developer and producer, in the next few years.

Pioneer focused on new oil at Oooguruk

In Alaska, Pioneer Natural Resources is focused on its nearshore unit, Oooguruk.

After building a gravel island in the state waters of the Beau-

fort Sea north of the Kuparuk River unit, Oooguruk came online in June 2008.

In early 2009 Pioneer increased its resource estimate for the unit by 40 percent based on initial drilling results.

Initially the company worked only at producing the Kuparuk pool and the deeper and larger Nuiqsut pool, but after years of drilling wells through the shallower Torok, it accumulated enough information to justify developing that formation.

According to Pioneer, Torok consists of 200-250 feet of thinly laminated sands and shales some 1,000 feet above Kuparuk.

Pioneer has drilled 18 wells through the formation, its first producing at an initial rate of 1,100 barrels per day.

Because the Torok reservoir extends past the southern boundary of Oooguruk, and a considerable distance from the existing gravel island, Pioneer proposed the Nuna Development Project in late 2010. The project would include two new onshore drill sites on the east side of the Colville River to allow Pioneer to approach the reservoir from the opposite direction.

The plan currently calls for processing that oil through existing facilities, but Pioneer also held out of the possibility of building a standalone facility.

The Kuparuk River unit currently processes Oooguruk crude, but pioneer is facing problems with that arrangement. In addition to being at the whim of the maintenance schedule of the larger and older field, Pioneer recently said it lost some 2,500 and 3,000 barrels of oil per day of production in 2011 because of water shortages.

The Division of Oil and Gas approved formation of the Torok participating area in July 2011 and agreed to add four leases to the Oooguruk unit in September to bring the entire reservoir into the unit's boundaries.

Pioneer estimates the Torok holds 690 million barrels of oil in place and that it can produce up to 25 percent through primary and secondary recovery methods, which could greatly exceed current Oooguruk production.

The state gave Pioneer until June 30, 2014, to sanction the Nuna development.

Should Pioneer move ahead, it said it plans to build the gravel roads and the first Nuna drill site pad June 30, 2015, in order to begin drilling in the expansion area by 2016.

This winter it plans to drill two wells as part of that program.

ASRC sees Placer potential

Nestled between the Kachemach and Southern Miluveach units, the ASRC Exploration-operated Placer unit covers four leases and 1,480 acres.

The company is beginning its first solely owned exploration project, its main target the Kuparuk C sand.

Under its unit agreement, ASRC must reprocess and reinterpret newly licensed seismic data shot across the unit by the end of the year, and must drill and log a new exploratory well, or reenter and test the Placer No. 1 well, by June 30, 2013.

ENS pearls about to be strung?

It has been more than 20 years since the phrase "string of pearls" was coined for the infrastructure-led exploration of Alaska's eastern North Slope. It has taken two more decades for the "string" — a metaphor for new pipelines — to come close to making its way from Pump Station 1 of the trans-Alaska oil pipeline at Prudhoe Bay to the Sourdough discovery on the border of ANWR's 1002 area, some 70 miles east as a goose flies.

Four billion barrels on and nearshore

Depending on which agency or company you ask, you will get different estimates for undiscovered, technically recoverable conventional oil resources onshore the North Slope and in adjacent state waters.

According to the agency the State of Alaska normally most trusts, the U.S. Geological Survey, the magic numbers for the area between the Arctic National Wildlife Refuge on the east and the National Petroleum Reserve-Alaska on the west, are 2.6 billion barrels on the low end; 3.9 billion as a mean average; and 5.9 billion on the high end.

Those are 2005 numbers using 2004 technology.

But because the estimates also contain resources in small, non-economic accumulations, USGS said the mean volumes are unlikely to ever be produced.

In ANWR's 1002 area, USGS estimates run the gamut from to 5.7 to 10.4 to 16 billion barrels.

Between the two are numerous on- and offshore discoveries, several of which are thought to hold upwards of 100 million barrels of oil.

The first "pearl" on the string was Endicott in the Duck Island unit, 15 miles east of Prudhoe Bay.

Next, in 1998, BP's Badami field came online, its 22-mile pipeline, or "string," connecting it to Endicott.

Although the 35,000-barrel-per-day line was supposed to be nearly filled by 30,000 barrels from Badami at its peak, the line

continued on next page

UNTAPPED CRUDE *continued from page 41*

was expandable, and its corridor would allow for a second and larger pipeline if needed.

Within a year of starting production at Badami, BP with several partners was drilling the Red Dog prospect, its next pearl to the east, between Badami and the undeveloped Point Thomson unit, which was operated by ExxonMobil, and of which BP was a sizable owner.

Unfortunately, BP was unable to finish the Red Dog well before the winter drilling season ended.

It was also experiencing serious problems at Badami. While early production had ramped up, as expected, to 18,000 barrels a day, by early 1999 it had dropped to a mere 3,000 barrels.

One of the challenges in developing the field — a known risk going in and part of the reason the capacity of Badami's pipeline was reduced from 70,000 to 35,000 bpd — was the question of whether its pockets of oil-bearing sands, or channels, would "communicate" so that oil would move from one to the next and into the vertical wellbores.

Published descriptions of Badami's Brookian accumulation suggest its reservoirs are complex, consisting of 61 identified fans laid down during seven depositional events, with thin and discontinuous reservoir-quality sands.

Following a series of startups and stops, and a great deal of effort to get the reservoir to perform, BP shut down Badami and its pipeline for the last time in 2007, with pro-

continued on page 63

OCS PRODUCTION *continued from page 33*

Slope.

A well drilled by Shell into the Burger structure in an earlier phase of Chukchi Sea exploration, around 1990, discovered the gas pool, but Shell also thinks there is oil at Burger, based on evidence such as oil staining found in rock samples from the old Burger well and pressures in the lower part of the Burger structure.

Pete Slaiby, Shell's vice president in Alaska, said in September that seismic data gathered from Burger by both Shell and ConocoPhillips prior to the 2008 lease sale had clearly generated enthusiasm for the prospect, given the high bonus bids the companies had offered for Burger leases.

"We truly believe this (prospect) is a game changer," he said.

Shell also sees the Beaufort Sea OCS as having major potential for oil and gas. In addition to its Camden Bay leases, the company owns federal leases in Harrison Bay, on the northwest side of the central North Slope, where it is rumored to also be taking an interest in state leases (see On Deadline section on page 8).

"There's the potential for years of production (in the Beaufort Sea) at Gulf of Mexico deepwater kinds of flow rates," Slaiby said.

Slaiby told Petroleum News that Shell has also been evaluating potential pipeline routes across the National Petroleum Reserve-Alaska for the transportation of future Chukchi Sea oil east to the trans-Alaska oil pipeline.

Norwegian oil major Statoil, a partner with Eni on most of its Alaska OCS leases, is working on plans for Chukchi Sea exploration, determining the resources it needs and deciding on the timing of any exploration drilling, Lars Sunde, the head of Statoil's Anchorage office, told Petroleum News Sept. 7. The company now has the final results from the 3-D seismic survey that it carried out in its leases in the fall of 2010 and is assessing the results, anticipating a drilling decision by the middle of 2012. Meantime, Statoil has started work on permitting for eventual drilling, Sunde said.

The company has identified two to three prospects from the seismic and is assessing those in detail, having already named two of them Augustine and Amundsen. The prospects lie about 100 miles offshore, with the village of Wainwright being the closest point on the Chukchi Sea coast.

ConocoPhillips dropped most of its Beaufort leases in 2009, and is now focused on the Chukchi Sea, where it holds an interest in two prospects — some leases at the edge of Burger, and Devil's Paw, where Statoil is a 25 percent partner on 50 leases in the prospect.

In a January 2011 conference call, ConocoPhillips CFO Jeff Sheets said, "In the Chukchi Sea, we entered into an agreement to farm down 10 percent of our working interest."

That partner was China's Sinopec.

Make that six major international oil companies.

The great unknown: ANS shale

By KAY CASHMAN
Petroleum News

Having leased 500,000 acres to the south of the Prudhoe Bay and Kuparuk's oil fields in a 2010 state lease sale, Alaska newcomer Great Bear Petroleum is moving forward with plans to drill four to six wells to test the production of oil direct from the prolific source rocks of the North Slope. This "unconventional" type of oil play, sometimes referred to as shale oil or source reservoired oil, has become an exciting major growth area for the Lower 48 oil industry but is new to Alaska, and as such has created a great deal of excitement, and some skepticism, in the state.


JUDY PATRICK
ED **DUNCAN**

Great Bear President Ed Duncan makes it sound almost too good to be true: These three world-class source rocks, mostly shale, could kick Alaska's oil production up to 1 million barrels a day in just a few short years, requiring about 200 wells per year, he says.

But skeptics beware. Along with overcoming some major permitting hurdles in early December, Great Bear got a show of confidence when Halliburton, expert at extracting oil and gas from source rock in major resource plays outside Alaska, partnered with Great Bear on some of its North Slope acreage.

In the next year Halliburton, the world's second largest oilfield service company, will be conducting a parallel "proof of concept" multi-well program on Great Bear's acreage along the Dalton Highway, while Great Bear is executing a similar program to the south, also along the highway. (Go online to http://bit.ly/rtkXIZ for slides used by Duncan in his latest public presentation.)

Still, there are a lot of unknowns and uncertainties about whether the horizontal drilling and fracking techniques that have proven so successful in the Lower 48 states will work on Alaska's rocks; and, if they do, will be economical in an Arctic environment.

The U.S. Geological Survey, in the process of conducting an assessment of northern Alaska's shale oil resources in northern Alaska, anticipates publishing the results in January or February 2012.

On the Web

Previous Petroleum News coverage:

- "A source of uncertainty" in Nov. 13, 2011, issue at http://bit.ly/tOLfge
- "Halliburton in the game," in Nov. 6, 2011, issue at http://bit.ly/sanJ5N
- "Taking a look at NS shale oil potential," in Oct. 2, 2011, issue at http://bit.ly/uW8xN3
- "Great Bear advances drilling plans," in Sept. 25, 2011, issue at http://bit.ly/qEnfI6
- "A source concept," in the Nov. 7, 2010, issue at http://bit.ly/mTph9b

"Great Bear on slope" in Oct. 31, 2010 issue at http://bit.ly/tUYrMi

Gara exposes 'oil giveaway' in debate

House representative opposes governor's House Bill 110 to reduce oil tax rate

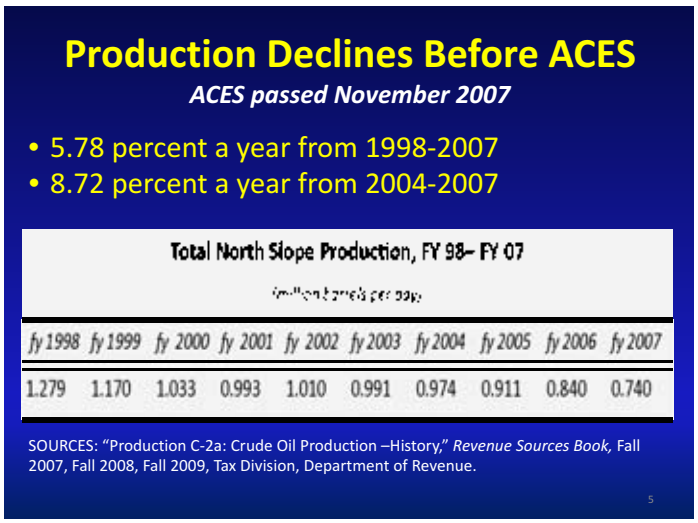
The following press release was posted on the website of Alaska Rep. Les Gara after a Nov. 14 debate at the University of Alaska Anchorage between Gara, an Anchorage Democrat, and Bruce Tangeman, deputy commissioner of the Alaska Department of Revenue. The release has not been edited or altered in any way. Anchorage-based Alaska Dispatch reported that at the end of the two-hour debate a member of the audience asked for a show of hands on who won the debate, and "a large majority in the audience thought that it went to Gara." A clarification at the bottom of the article, which can be found at http://bit.ly/vMcBQI, said Gara doesn't think Alaska's current production tax, ACES, is perfect and that he has sponsored a bill that would add additional tax credits for exploration to it.

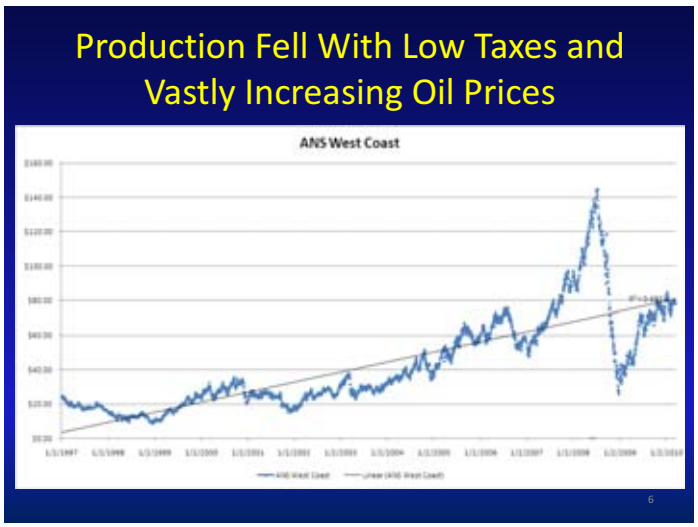
LES **GARA**

Today, Representative Les Gara articulated why giving away billions of dollars of Alaska's oil revenue as the governor proposes will not increase development on the North Slope but will instead wipe out the $15 billion in savings Alaska has achieved under the current law, putting Alaska's economy, now and into the future, at great risk. Rep. Gara made his case in a debate on the governor's proposed multi-billion dollar oil giveaway hosted by the Union of Students student government at the University of Alaska Anchorage.

"His plan is based on a hope, wing and prayer that companies will not take that $1.8 billion a year in tax breaks, and just send it to executives and shareholders in Texas and London," said Gara. "Alaska has tried low taxes like the Governor plans before, and it was a disaster. Until 2006 we had a system that essentially guaranteed a 0 percent Production Tax on new fields. Under that law, production was falling faster — at almost 9 percent a year — and we had 40 percent less investment and employment on the North Slope. Giving away money in low taxes, and just hoping companies don't send that money to their shareholders and executives in London and Houston, like they did before 2006, simply doesn't work," said Rep. Gara.

In the debate with a member of the Parnell administration, Rep. Gara presented facts showing exploration and jobs on the North Slope are both higher under the current tax structure—which requires companies to invest in Alaska to get tax breaks—than under previous tax regimes where oil companies paid little to no tax on most fields, and weren't required to invest in Alaska to achieve tax breaks. Instead of the governor's giveaway, Gara proposes in House Bill 231 that Alaska only grant tax incentives to companies that drill in new areas and build processing facilities to put new oil into the pipeline.





"The governor wants to give away billions without even a commitment from industry as to what Alaska will get in return," said Rep. Gara. "That's a deal no CEO would ever make for his company. Our resource is worth more now than ever, and if Alaskans are going to forgo any of that value, we better know exactly what we're getting in return."

At the end of the program, a member of the audience asked if others in the room leaned more toward Rep. Gara's position or toward the Governor's. After hearing both sides for almost two hours, the audience overwhelmingly sided with Rep. Gara.

Watch the whole debate at http://www.livestream.com/usuaastudentgovernment

See the rest of Gara's slides at http://bit.ly/vnohwK

Impediments to filling TAPS

Insights, advice for legislators from small Alaska independent run by former ARCO exec

Following is a letter Jim Weeks, managing member of Alaska independent UltraStar Exploration, sent to Rep. Paul Seaton, co-chairman of the Alaska Legislature's House Resources Committee for an early November meeting about impediments to filling the Trans Alaska Pipeline System, or TAPS. Weeks is a former long-time senior vice president of ARCO Alaska. His letter has been edited slightly, to meet Petroleum News formatting and space requirements.

There is a single phrase to describe what determines and impedes the sustaining of volumes through the TAPS as the legacy fields on the North Slope continue to decline. And that is "cost structure." The lower the state can make the cost of producing and shipping liquid hydrocarbons through TAPS, the longer the resource will last and the more oil will ultimately be produced. With lower cost structure, more new fields will be found, brought on line and last longer.

JUDY PATRICK

JIM **WEEKS**

We've got to stop thinking about a world beyond petroleum, and spending significant money trying to force-fit projects of marginal significance into the energy mix. Oil has been good to and for all of the State of Alaska, and there is no reason to believe it cannot be for decades to come. We are advantaged in that we have world-class oil fields producing into a world-class pipeline. So let us stay in the game, compete fiercely for investment dollars, and extend the field lives as long as possible — through as low a cost structure as possible.

Following is what can the state do, both in the near and long term:

1. Reduce state's take

Lower the state take by passing House Bill 110 or some similar measure. The state take at current price levels is simply too high, and is siphoning off money that should be re-invested in projects to extend field life and find new fields.

I know there is a contingent of legislators with the firm belief that rig counts are up, employment is up, etc. etc. because of ACES, the state's current production tax, so everything is fine, and the state is enjoying huge windfall budget surpluses as a result of currently high oil prices and ACES progressivity tax rates. It is like we're intoxicated on the high revenue stream, and we want it to continue.

But everything is not fine. Sure, the tax credits authorized in ACES are a tremendous incentive to companies like ours and others who are currently exploring, and we certainly hope the credits stay in place for a long time. UltraStar's last well, in 2009, would not have been drilled without them.

But UltraStar and the smaller players cannot meaningfully increase TAPS throughput. We simply don't have the balance sheet or the leasehold. The major leaseholders, BP, ConocoPhillips and ExxonMobil who do have the balance sheets and lease positions, need to participate, but are not because of the tax structure of ACES.

Lease sale contracts require ice roads and pads for exploration outside of the limited gravel road system, usually restricting the exploration season from mid-January to no later than about April 15.

JUDY PATRICK

Sure, they receive the same tax credits we do, but to them these credits are nice, but pale compared to the huge tax bill they pay each month.

They are not drilling wildcat wells, and if HB 110 were passed, would no doubt pick up the pace of development of heavy oil resources in both the Prudhoe Bay and Kuparuk River units, overlying the primary productive zones.

> *But UltraStar and the smaller players cannot meaningfully increase TAPS throughput. We simply don't have the balance sheet or the leasehold.*

There is a target of 50 billion barrels of heavy oil in the West Sak/Schrader Bluff and Ugnu formations. These are known, drilled, proven resources. There is nothing speculative about them except their technical feasibility and economic viability.

They are shallower, thus colder, and the reservoir rocks haven't been buried to a depth sufficient to consolidate the sandstones. Being colder, the oil is viscous, like molasses, and the sandstone formations are like beach sand.

But the size of the targets cannot be ignored. Combined, they are orders of magnitude bigger than all the prospects of the current group of independents combined, with the possible exception of resource plays, which I'll discuss later.

Probably the most significant challenge faced by these economically and technically challenged heavy oil resources is that production from them is subject to the very high production taxes in ACES, which is exactly the wrong direction the state should be headed. This heavy oil already costs significantly more to develop, and on top of that they are burdened by an exorbitantly high marginal tax rate. Exactly the wrong strategy for a tax policy with filling TAPS as a goal.

continued on next page

WEEKS *continued from page 45*

In the oil business, it never fails that when a field is being developed and waterflood is being implemented, the reservoir engineers, subversive creatures that they are (I can say this because once upon a time I were one), select the best oil producers to be converted to water injectors. So oil stops coming out and water starts going in.

Once this happens, of course, the immediate impact on the daily oil production rate from those converted wells drops significantly, as, depending upon the waterflood pattern, 40-50 percent of the total wells in a field can be injectors. This near-term production loss is more than made up over the long term, as waterfloods generally increase ultimate recovery by 25-50 percent or so.

But the near-term effects on revenue are quite painful. Waterflooding is often compared to delayed gratification. It takes an adult to appreciate it.

The current situation in Alaska is analogous to waterflooding a reservoir. With his proposed ACES revisions, the governor wants to implement a waterflood, to significantly increase ultimate recovery in the long term.

Those opposed to his plan want to continue to enjoy the high brought on by the immediate gratification from the double effect of the high tax rates in ACES coupled with high oil prices.

It is far better to lower taxes now on existing production, and particularly production of heavy oil, so we can enjoy the benefits of lots of new production for many years to come.

It mystifies me why the state would impose one of the highest marginal tax rates in the world on one of the highest cost resources in the world, heavy oil on the North Slope.

There is a target of 50 billion barrels of heavy oil in the West Sak/Schrader Bluff and Ugnu formations. These are known, drilled, proven resources. There is nothing speculative about them except their technical feasibility and economic viability.

It is the only resource there that can make a significantly positive difference in the near term.

It is huge, it is known to be there, and it is connected to the roads, pipelines and processing plants.

So let's go after it in a frenzy.

2. Roads to resources

I coined the phrase 'Roads to Resources' in a speech to the RDC annual conference almost exactly 10 years ago to this date. The phrase still exists, but unfortunately no roads do.

Thanks to the Murkowski administration, which adopted the strategy, and the Parnell administration, which continues pursuing it, progress has been made and continues to be made, and that is good.

On the North Slope, there are two proposals: one for a road connection from the Dalton Highway east to Bullen Point, and one to the west to Umiat, which is further advanced. The governor is certainly behind Roads to Resources, and thanks to you in the Legislature these projects continue to move forward. I fear they will not get done without continued push from both the administration and Legislature.

It mystifies me why the state would impose one of the highest marginal tax rates in the world on one of the highest cost resources in the world, heavy oil on the North Slope.

These projects are under attack by aboriginal groups expressing concern of the impact they may have on subsistence lifestyle and the usual environmental groups, who oppose anything that may enhance the economics of resource development, and concerns about funding.

I think that funding could be the Achilles heel for these needed projects, which will lower the cost of exploration and development far in excess of what anyone can now envision.

I implore you and your colleagues in the Legislature to think out of the box to structure creative ways for these important projects to get done.

Think of when the U.S. Congress authorized the construction of the transcontinental railroad. They did not do a lot of cost/benefit analyses, and they gave the railroads every other section of land, checkerboard style, on both sides of the right of way as incentive to build the tracks and terminals.

The state owns virtually all of the land these roads are proposed to pass through. Perhaps you should do something similar, or even, heaven forbid, consider investing, yes investing, a very small percentage (1-2 percent), of the Alaska Permanent Fund in these roads.

I said investing, not spending, a small percentage. The returns will be enormous. I'll guarantee you the U.S. Congress did not do a bunch of net present value calculations when they authorized the railroad, nor the Eisenhower Interstate Highway system, both of which are extremely important to the national economy.

But investing permanent fund earnings now on infrastructure projects that will pay off handsomely in the future may decrease the fund's principle and earnings and the dividend check. So the people would be risking the instant gratification they currently receive from an annual permanent dividend fund check for a greater delayed gratification from a potentially much larger future PFD check. All enabled by revenue from the resources that will be developed as a result of having lower access and extraction costs.

How about a rail extension of the Alaska Railroad to the North Slope and points east and west?

How many times is the state going to re-build and re-repair the road and bridges on the Dalton Highway?

Some will say it is too late for a railroad extension to make any sense. That it should have happened 30 years ago.

I contend that the North Slope is still in its late adolescence. I was raised in an oil field in south-central Wyoming that was first drilled in the mid-1910s. It is nearly 100 years old now and is still producing, not only oil, but good paying jobs and taxes for the State of Wyoming and Sweetwater County. And it has yet to experience the shale oil boom that is expanding into the area. That boom is in the Niobrara Shale in northwest Colorado and southern Wyoming, about 50 miles south of my home town.

I wish Great Bear great success with its plans to test the viability of oil production from the known shales on the North Slope. Success here will definitely be a game changer for Alaska and the North Slope, and Alaska should be ready with the infrastructure to make that game as competitive as possible.

Every new well at Prudhoe requires 50 truckloads of freight to supply it. The pipe, mud, cement, equipment, supplies and materials that go into the ground.

Because of their large horizontal components, shale oil wells will require probably twice as many truck loads per well, and much, much more fracturing and completion services.

Lowering the cost of transportation to the North Slope will add enormously the number of ultimate wells drilled and barrels of oil produced.

3. Ice roads and pads

A change to the current lease form by the Division of Oil and Gas could lower the cost of and speed up exploration and development of new fields that are off the existing road system.

As it now is, the successful bidder at a lease sale is awarded a contract to explore, develop and extract oil and gas from that lease. The contract stipulates that there will be no exploration on the lease except from approved ice roads and pads, built only when there is sufficient snow cover and frozen depth to carry the heavy loading of drilling rigs and equipment.

This restricts the exploration drilling window to generally mid-January to no later than about April 15, depending upon the status of the well.

So there is essentially a 90-day period in which to construct the ice road and pad and move in the rig and associated 50 truckloads of parts, plus camps, shops, generators, fuel storage tanks and other supporting facilities.

A change to the current lease form by the Division of Oil and Gas could lower the cost of and speed up exploration and development of new fields that are off the existing road system.

This restrictive window allows for one, and certainly no more than two, wells to be drilled per rig per season.

Companies like Repsol, with nearly 400,000 acres to explore and delineate, will require multiple years to prove up commercial reserves and make plans for development. So they will need to re-build the needed ice roads and pads multiple times before development decisions are made.

Linc Energy faces a similar challenge at Umiat.

The state should let private industry decide the most efficient and lowest cost manner to conduct exploration.

Ice roads and pads may be the best way forward for close in exploration. But for access to locations farther from the road system, re-building ice roads every year for several years gets pretty expensive.

The leaseholder should not be restricted from using any method, with appropriate approvals of course, to access his or her leases.

If existing, or newly constructed permanent or semi-permanent gravel roads, airstrips and drilling pads would be more cost effective, they should be allowed.

This could provide year round access to the leases being explored, and shorten times from lease to production by years. The ability to drill throughout the year will also significantly shave the winter peaking demand for drilling equipment, materials and manpower, thereby further reducing costs.

An all-weather road to the location of the drilling also provides year round access for emergency response equipment and personnel, adding another level of safety to the already very high operating standards for humans and the environment.

Thanks for the opportunity to comment.

Marks: Progressivity dysfunctional

Economist says Alaska not competitive for investment with comparable oil provinces

By KRISTEN NELSON
Petroleum News, March 20, 2011

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, or PPT, in 2006.

Alaska's Clear and Equitable Share, or ACES, 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 jurisdiction 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 and most of Statoil is owned by Norway.

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.

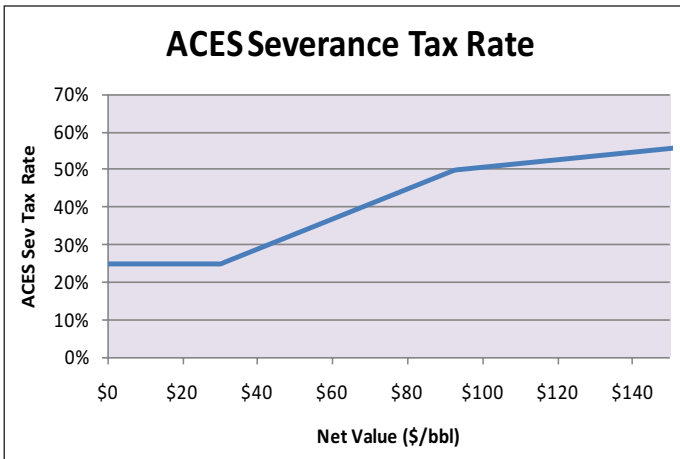
Companies have made billions of dollars in Alaska, Marks said, but the issue isn't how much they can make in Alaska, it's how much more money they could make in other places.

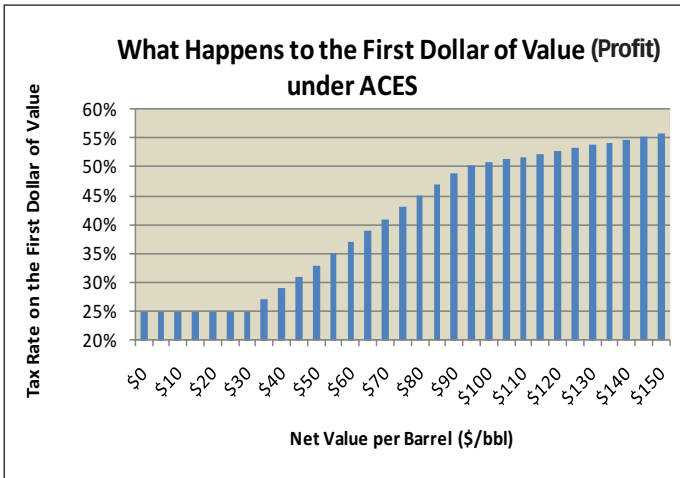
On the issue of ConocoPhillips' Alaska profits compared to the Lower 48, Marks said it's about the difference between oil and gas. In Alaska the company's assets are more than 90 percent oil, compared to about one-third oil in the Lower 48 where the company primarily has natural gas assets and internationally, 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.

ALL CHARTS COURTESY ROGER MARKS

Tax Rate under ACES

- Base rate of 25% of net value (after deducting all costs)
- Progressivity element when net value per barrel exceeds $30/bbl:
  - (Net value per barrel value - $30) X .004
- If oil market price is $90/bbl:
  - Net value per barrel is $58/bbl
  - Progressivity = ($58 - $30) X .004 = 11.2%
  - Total tax rate = 25% + 11.2 = 36.2%
  - 36.2% X $58 X 0.875 (non-royalty) = $18.37/bbl
  - **APPLIES TO ENTIRE NET VALUE**

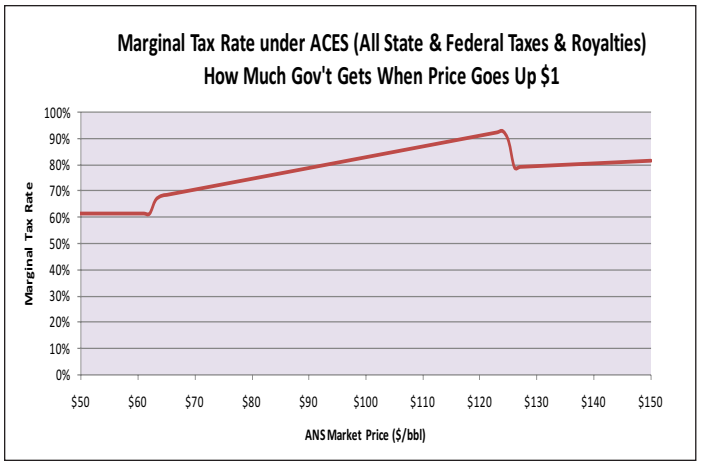


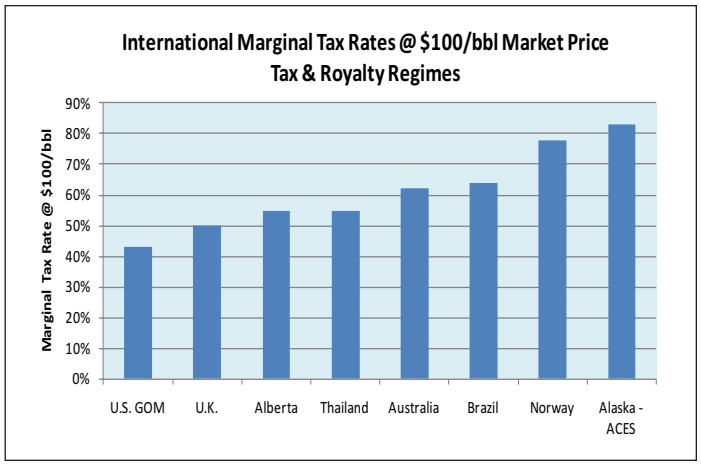


The worldwide competition for investment dollars, Marks said, is oil vs. oil.

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.

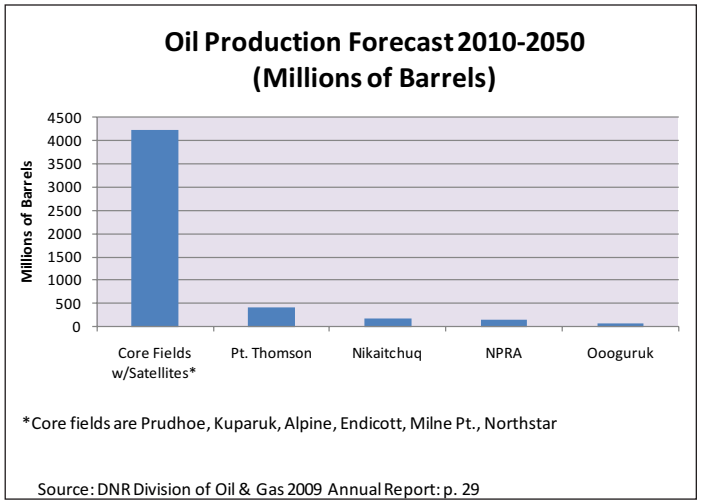
Both the Department of Revenue and the Department of Natural Resources do production forecasts. DNR's forecast has gone out to 2020 since 2000, and while it isn't annual, there have been six forecasts since 2002, Marks said.

Marks compared a 2006 DNR forecast, the last prior to passage of PPT, in which production of almost 900,000 barrels per day was projected for 2010, dropping to some 675,000 bpd by 2020, with a November 2009 forecast, the most recent, which had 2010 production at less than 650,000 bpd and 2020 production dropping below 500,000 bpd.

The difference isn't a matter of fields DNR thought would come online but haven't, Marks said, because more than 80 percent of the oil in DNR's forecast comes from core fields.

Is it all due to ACES? Marks said he didn't think it was all attributable to ACES, but thinks ACES is a major contributor. When DNR estimated 900,000 bpd in 2011 that 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

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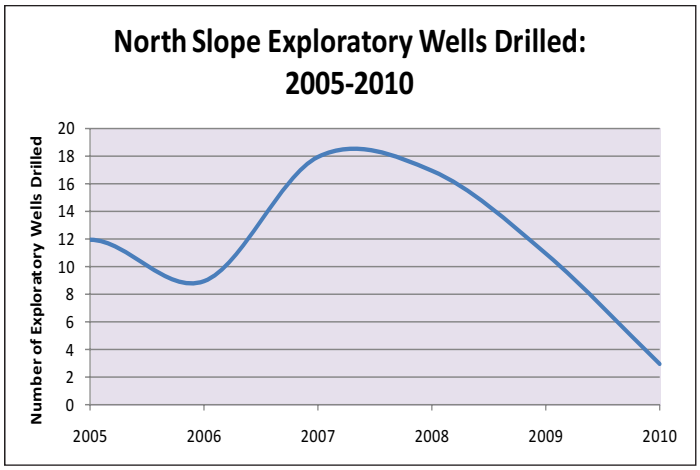
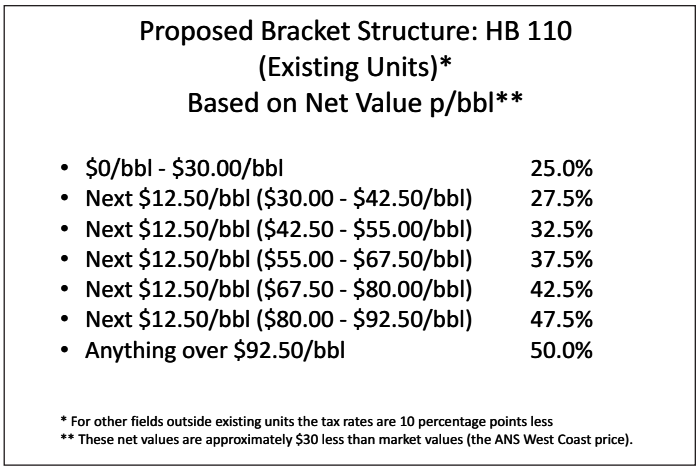
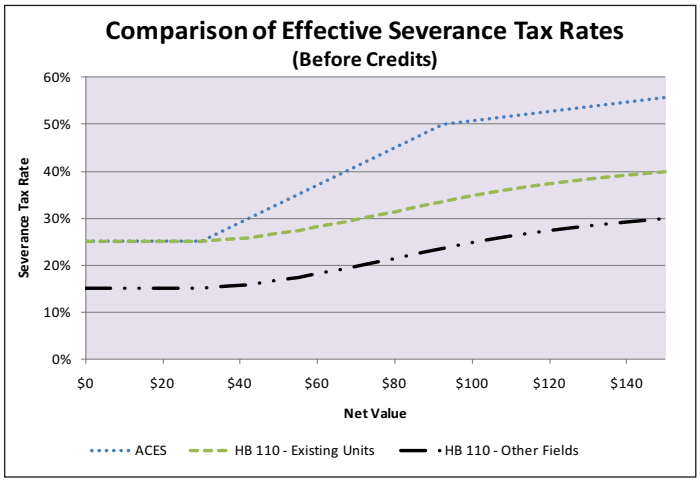
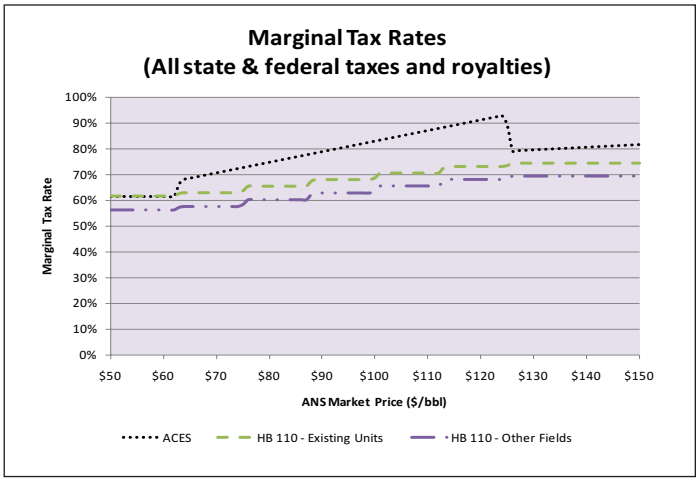








MARKS *continued from page 49*

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 taxes, he said.

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

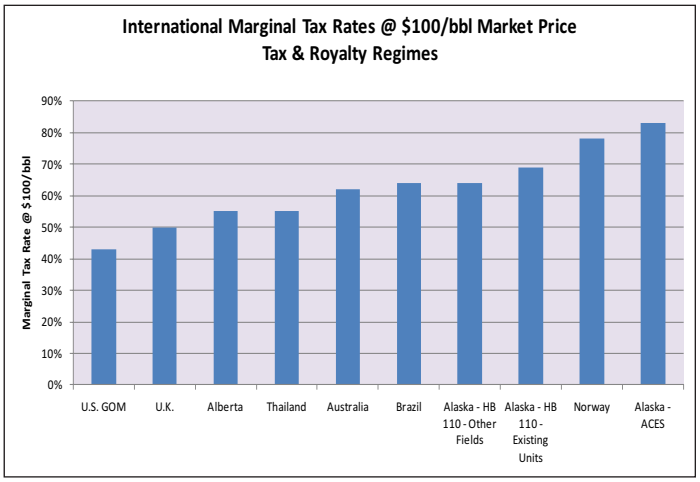
Marks noted that while the state has made changes in oil and gas taxes in the past, those changes have always increased taxes. He told legislators this is the first time they've been faced with decreasing taxes, and said he appreciates it's a hand-wringing experience.

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.

Editor's note: Rep. Mike Hawker is chair of the Legislative Budget and Audit Committee, or LB&A. House Bill 110 may carry Gov. Sean Parnell's name, but it bears the shadow and the will of Hawker. The Anchorage Republican was the first to introduce an oil tax rewrite bill before the Legislature returned to Juneau in January. But he yielded to the governor's proposal to rewrite the state's production tax system, known as Alaska's Clear and Equitable Share, or ACES. He attended nearly every House Resources hearing before the bill reached the House Finance Committee. There, Hawker first served as an alternate before being moved to a voting member after Rep. Mark Neuman took a leave of absence. The bill passed the House in 2011 but its companion bill has not been passed by the Senate.



Read Marks' evaluation of ACES, requested by LB&A at http://bit.ly/sbGWqp

Read minutes of March 15 House Finance Committee with Marks' testimony http://bit.ly/uFdnsj

See the rest of Marks' presentation slides at http://bit.ly/rRh8Mn

Alaska and its peers

November update from Marks' February report, overview of fiscal competitiveness

UPDATE **By ROGER MARKS**
Provided Nov. 30, 2011

Capital is required to produce oil. At the corporate level capital is finite and capital is fluid. Capital will go where it will get the best deal. Thus jurisdictions and projects compete for capital.

The fiscal piece is a major determinant for profitability. Often fiscal costs can exceed development or production costs. Thus fiscal structure is a significant component of international competitiveness between jurisdictions.

Companies are willing to pay more taxes when the reward is greater (lower risk/lower costs/higher reserve potential). Thus in comparing fiscal regimes it is important to look at comparable jurisdictions in terms of operating environment, costs, risks, reserves, etc.

For example, if you were selling a 1,500 square foot house, you would not want to look at sales of 6,000 square foot homes to see what yours is worth. Thus Alaska cannot be compared, for example, with a low cost/vast resource regime like Iraq.

Thus in evaluating the adequacy of a fiscal system it is essential that you are comparing your fiscal system with that of its "peers," those jurisdictions with similar environment, costs, risks, reserves, etc.

Alaska's uniqueness (its operating environment, costs and distance from market) makes it difficult to find exact peers. However, one can find some similar jurisdictions in certain categories: for instance, there are 1) North American regimes, 2) tax and royalty regimes, 3) Arctic regimes and 4) jurisdictions with similar production/reserve characteristics.

Regarding the fourth category, Alaska produces about 600,000 barrels per day and has 3.6 billion barrels of proved reserves. (This is a DOE/EIA estimate based on confidential and mandatory reporting. Proved reserves are reserves that have at least a 90 percent probability of actually being produced.) For this exercise we found those jurisdictions that both produce between 500,000 and 1 million barrels per day and also have reserves between 2 billion and 8 billion barrels.

With the exception of category 3 (Arctic) many of these jurisdictions will have different operating characteristics from Alaska. In particular, most of them will have lower costs. In that regard we will actually be comparing Alaska with superior jurisdictions.

Based upon these four categories, we have developed a set of 23 jurisdictions that could be considered Alaska's peers. (See chart, next page: some jurisdictions are in more than one category):

As has been discussed prior, the problem with the progressivity structure of ACES is that it creates high marginal tax rates at high prices, which creates high

continued on next page

Alaska's peers

23 jurisdictions that could be considered Alaska's peers.

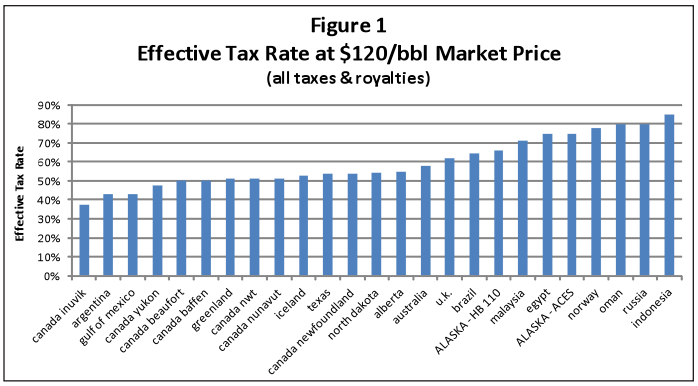
- Alberta
- Argentina
- Australia
- Brazil
- Canada Baffen Bay
- Canada Beaufort
- Canada Inuvik
- Canada Newfoundland
- Canada Nunavut
- Canada Northwest Territories
- Canada Yukon
- Egypt
- Greenland
- Gulf of Mexico
- Iceland
- Indonesia
- Malaysia
- North Dakota
- Norway
- Oman
- Russia
- Texas
- United Kingdom

MARKS UPDATE *continued from page 51*

effective tax rates. This takes away a large share of the upside potential from investors. By upside potential we mean the potential to make a lot of money at high prices.

Upside potential can be very important in shaping investment decisions. Even though the upside may be of relatively low probability, investors can make so much money when it does happen that it can make the investment worth pursuing. But, if the upside potential is suppressed, the investors may not see enough profit potential to approve the project, and the project may not happen.

Figure 1 shows the comparison of effective tax rates at a market price of $120 per barrel for oil. Effective tax rate is defined as all taxes and royalties divided by pre-tax net income. It is the percentage of net income that goes to government. This includes all taxes and royalties.



ACES at 75 percent is clearly among the highest. HB 110 at 66 percent is also relatively high.

And these differences in effective tax rates are not trivial. Given Alaska's cost structure and production volume, at $120 per barrel each percentage point of tax is worth about $170 million after-tax to the producers. (Current estimated upstream and downstream costs are about $32 per barrel. At a $120 per barrel market price that yields a net value of $88 per barrel. Production tax is only payable on the non-royalty 87.5 percent of production: $88 X 0.875 X 600,000 X 365 X .01 = $169 million.)

So for example, the 21 percentage point difference between Alaska (ACES) and North Dakota (75 percent vs. 54 percent) represents $3.6 billion in additional after-tax income to the producers. This is very significant.

Moreover, of these jurisdictions, besides Alaska, only Russia, Iceland, and Malaysia have progressivity. So at higher prices, which will have a bearing in upside potential, Alaska's effective rate will increase, while the others' (without progressivity) will not, making Alaska even more uncompetitive.

Of the four jurisdictions with higher effective tax rates than Alaska (Norway, Oman, Russia, and Indonesia) all have higher production than Alaska, all have higher reserves than Alaska, and all but perhaps the Russian and Norwegian Arctic have lower costs than Alaska.

Note that for Norway about 70 percent of production is owned by Statoil, 70 percent owned by the Norwegian government. So to a large extent the government is paying taxes to itself. Also, for Russia note that over half the effective tax is an export duty.

House passes reduced oil tax

Votes lacking in Senate to move bill from key committee; Stedman says don't rush it

By KRISTEN NELSON
Petroleum News, April 10, 2011

The battle continues in Juneau over changes to the state's oil and gas production tax, Alaska's Clear and Equitable Share or ACES, passed in late 2007 under the Palin administration.

Gov. Sean Parnell's bill to reduce production taxes in a bid to make the state more attractive for investment passed the House 22-16 on March 31; notice of reconsideration was given, but not taken up April 1.

The bill's fate in the Senate appears less certain and the clock is ticking, with this session coming to an end April 17.

The House version of the governor's tax bill has its first Senate hearing, in the Labor and Commerce Committee, on April 8; it then has referrals to the Resources and Finance committees.

In an April 5 Senate Bipartisan Working Group press availability, Senate President Gary Stevens, R-Kodiak, said that normally the bill would have gone just to Resources and Finance, but Sen. Dennis Egan, D-Juneau, the chair of Labor and Commerce, requested the referral to address some issues in his committee.

Stevens said Egan can move the bill fast, but once it gets to the Resource Committee, Stevens — who sits on that committee — said he didn't see the four votes out of seven that would be required to move the bill on to Finance.

Senate Resources has had hearings on the Senate version of the governor's bill and on a bill by Resources co-Chair Tom Wagoner, R-Kenai, which would offer credits for development work for new fields, the investments made between a discovery and when a field first has sustained production.

The production issue

Rep. Mike Hawker, R-Anchorage, a supporter of the governor's bill in House Finance, said at a House Majority press availability April 1 that declining production is the state's greatest challenge. He said he believes the state has ratcheted its taxes up to the point where it has lost investors because there are better opportunities for them elsewhere.

Hawker said the greatest concern among those opposed to the bill appeared to be where's the quid pro quo? We're going to give; what are we going to get?

But he said Alaska doesn't operate in isolation and while the state has great incentives for exploration drilling, Alaska has priced itself out of the market for development with its production taxes.

Parnell, joining the press availability to thank the House for the bill's passage, said there are members of the Senate who want to do something, and said he would work with the Senate to increase production. Alaskans won't stand for a do-nothing Senate, he said.

Making Alaska more competitive for investment needed to maintain and even increase production through the trans-Alaska oil pipeline is the governor's stated goal for the revision of the state's production tax.

Stedman's current position on ACES

Editor's note: Shortly after the November 2011 Resource Development Council's annual meeting in Anchorage, Alaska Sen. Bert Stedman, R-Sitka, wrote the following note on his website. Some of the research/information Stedman was waiting on before he made a decision on how best to amend Alaska's Clear and Equitable Share, or ACES, has come in. A link in the text below is to an interview Stedman gave after RDC. Be patient, as the portion on changing Alaska's production tax, ACES, starts about 20 percent of the way into the recording.

BERT **STEDMAN**

This week I attended the Resource Development Council's annual conference in Anchorage.

RDC is a statewide business association that represents Alaska's oil and gas, mining, timber, tourism, and fisheries industries.

The two day conference had over a thousand people in attendance and was an excellent opportunity to discuss Alaska resource policy.

Presentations ranged from oil and gas activity around the state, energy development, mining projects, and discussions on how to grow Alaska's economy.

In Southeast, resource based industries have always driven our economy. I've worked hard to fortify our commercial fisheries, protect timber jobs, and grow our visitor industry.

While in town I stopped by the FOX 4 KTBY television studio to talk about resource development with host Dan Fagan.

Oil and gas taxes will be one of the most hotly debated issues during the next legislative session. I was glad to have the opportunity to discuss how the state can maximize oil and gas development while ensuring Alaska gets its fair share of our natural resources.

You can watch the interview at this link: http://bit.ly/u4VDrr.

I appreciate RDC's hard work in hosting this event and enjoyed the opportunity to meet with business leaders and stakeholders on developing Alaska's economy.

—Bert Stedman

Fiscal notes for the governor's bill show that the tax rate change in current producing areas is estimated to total a reduction in revenue of $5.6 billion for the first five years — if there is no change in forecast production. If production rose 5 per-

continued on next page

HOUSE OIL TAX BILL *continued from page 53*

cent from present projections the reduction would be $4.8 billion over that period.

The administration has said it expects that if there is no new investment the Legislature would act to change the tax rate.

Negotiation without prospect of a return

Rep. Beth Kerttula, D-Juneau, the House minority leader, said at a House Minority press availability April 5 that the bill's most fundamental problem is that it's a negotiation without any prospect of a return. The bill passed the House after a long floor debate, she noted, and said that while the final vote spread was larger, opponents were within two votes of defeating the bill on the floor.

Rep. Les Gara, D-Anchorage, a vocal opponent of the bill in House Finance and on the floor, said the bill requires no reinvestment and no new production, but would allow the North Slope's major producers to simply take tax savings under the bill out of the state.

Gara offered amendments both in committee and on the floor which would have removed the governor's proposed bracketing in progressivity — a system such as used by the Internal Revenue Service for individual tax returns — and replaced it with credits to incentivize more investment.

What next?

Sen. Bert Stedman, R-Sitka, who sits on Senate Resources and is co-chair of Senate Finance, said April 5 that Senate Finance has had significant concern for several years over declining production — nothing new there.

And he noted that legislators started discussions on tax changes in the Legislative Budget and Audit Committee last summer and purchased $96,000 in studies. A portion of one study on the Arctic isn't due until June and the final review of five other studies isn't due until September.

He characterized pressure to move forward on the bill as elected officials being told to make decisions on billions of dollars of the state's resources and in the next breath being told not to worry about the technical details of the analysis, just vote.

Audits aren't even available from the Department of Revenue on ACES, and $34.7 million is being added to the capital budget to allow the Department of Revenue to accelerate purchase and implementation of tax software to help accelerate the audits, Stedman said.

He said the bills won't die and there will be work done in the interim and the Legislature can pick the bills up when it reconvenes in January.

Editor's note: The headline and deck of this article were changed to fit a magazine format.

GOVERNOR'S BLUEPRINT *continued from page 29*

and deepen cooperation. Additionally, despite the Obama administration's focus on shutting down resource development in Alaska over the past two years, we are redoubling our efforts to work with the feds."

Promoting Alaska investment

The fifth and last part of the governor's plan to increase North Slope production and TAPS flow to 1 million barrels a day by 2021 was to promote Alaska resources and positive investment climate to world markets. Its three key components were:

- Make the case on the strategic importance of domestic production and Alaska's role.
- Promote Alaska to increase investment.
- Boost public knowledge about our resource base, favorable political and investment climate, strong commitment to environmental protection, and desire to welcome the investment needed to increase production of oil, gas, and other resources.

"We compete on a global stage for capital investment. We need to boost public knowledge," Sullivan wrote in his June 4 editorial.

"Alaska faces many challenges. But they are outweighed by the opportunities we have, particularly as they relate to our natural resource wealth — the envy not only of other states but of most countries. All Alaskans have a role to play in responsibly developing our resources to ensure a bright future for our fellow citizens," Sullivan wrote.

"It's time we get to work."

HEAVY OIL *continued from page 32*

heavy oil we can get off the Slope."

In 2009, BP's reservoir scientists and engineers said there was about 20 billion barrels in the heavy oil Ugnu formation, estimating that roughly 10 percent, or 2 billion barrels, of that resource could be recovered.

In an April 2011 speech, BP's president in Alaska, John Minge, talked about a study indicating it was possible to develop 2 billion barrels of heavy crude "with technology advancements that we believe are achievable" and would require on the order of 2,000 more wells on 50 pads with a new gathering center and a hundred miles of new pipelines.

The development would require surface facilities to handle lower-grade, solids-laden crudes, Minge said.

Claire Fitzpatrick, chief financial officer and senior vice president of BP in Alaska, said this project and others will remain a possibility unless Alaskans and the oil industry work together to make changes to make it commercially viable and competitive.

BP's current plans include continuing the heavy oil pilot that's on line, "but we'll not be investing in any further heavy or viscous development beyond some studies over the next couple of years," she said.

Editor's note: Viscous oil production from Alaska's North Slope is currently about 45,000 barrels a day, depending on the definition of viscous used by the reporting company or agency. Viscous oil has the consistency of maple syrup; heavy oil is like molasses. That production comes from an estimated 6 billion barrels of in-place viscous that is in currently producing North Slope fields — 4 billion barrels in the West Sak/Schrader Bluff formation in the Milne Point and Kuparuk River units and 2 billion barrels in the Schrader Bluff formation in the Prudhoe Bay unit (Orion and Polaris satellites), Nikaitchuq and Oooguruk units. An additional 1 billion barrels of viscous production is possible. Beyond the Milne Point test facility, heavy oil is not in production but it represents a much bigger prize.

Five not-so Easy Pieces

How might Alaska be shipping 1 million barrels a day through TAPS in a decade?

By DAN DICKINSON, CPA
For Petroleum News

Alaska Gov. Sean Parnell has articulated a goal for Alaska of a million barrels a day of oil flowing through the Trans Alaska Pipeline system, TAPS, a decade from now. Three and a half decades ago in 1977 oil started moving through TAPS from the North Slope to the Lower 48 (and very occasionally other) markets, increasing every year until it peaked at just over 2 million barrels a day in 1988. In almost every year since then, the North Slope has produced less oil than the year before, with the result that 2002 was the last time TAPS averaged over 1 million barrels per day. In the decade since then production has fallen to around 650,000 bpd.

One way to think about this challenge is to assume a flat base of 635,000 bpd. To return to 1 million bpd means that every day, for 365 days a year over the next date decade or 3,650 days, Alaska must add 100 bpd of new production. No Saturdays and Sundays off, every Monday there must be 700 more barrels in the pipeline than the previous Monday. However, instead of a flat base year to year North Slope production is declining at almost that same rate the governor wants it to grow by. Currently everyday on average 100 fewer barrels — rather than 100 more barrels — go into TAPS than the day before. (6 percent decline times 650,000 barrels/365 days a year). The latest Department of Revenue forecasts project North Slope production at roughly 500,000 bpd by 2020. That means that Alaska would need to add well over 100 bpd of production more than is currently forecast very day of the decade to be producing at a million bpd by decade's end.

Is this possible? Here are five scenarios.

1. Giants Needed

While Alaska needs more than an additional 100 bpd of new production every day it is not likely to achieve that through thousands of small producers — each producing 100 bpd bringing a new well on daily. In fact the easiest way is to find another supergiant field like Prudhoe Bay — or a field even half the size of Prudhoe Bay. In 1988 when the entire North Slope was producing 2.1 million bpd, 1.6 million bpd was coming from the single field at Prudhoe Bay.

Giant oil fields are generally considered to be those that produce over 500 million barrels over their lives: The definition of a supergiant is a little looser but generally it's a field that is an order of magnitude larger or 5 billion barrels. The Prudhoe Bay field — which has already produced 15 billion barrels and has billions left — definitely meets the definition of a super giant.

The next biggest field on the North Slope is Kuparuk, which has produced about 2.5 billion barrels — so it is a giant, in fact a very large giant, but not a 5 billion barrel plus supergiant. Several Kuparuk like fields would have to come on line over the next decade to meet the 1 million bpd goal. However, if the Department of Revenues Forecasts are to be believed, the more typical North Slope giants will prove to be Endicott (brought on line in 1988), Alpine (2001) perhaps even Milne Point (on line in 1986) or Point Thomson (yet to come on line). It would take five more of these typical giants — one every other year for the next decade — to reach 1 million barrels. This is a considerably different pace than the historical rate of essentially one new giant every 10 years.

continued on next page

About the author


AL GRILLO
DAN **DICKINSON**

Trained as a geologist at Brown University and currently holding a certified public accountant's license for Alaska, Dan Dickinson has served in several state and municipal administrations, including as the director of tax for the State of Alaska. His consulting practice concentrates on state and local taxes, or SALT, with a focus on oil and gas. The spectrum of his work ranges from compliance and mechanics to long range fiscal policy issues.

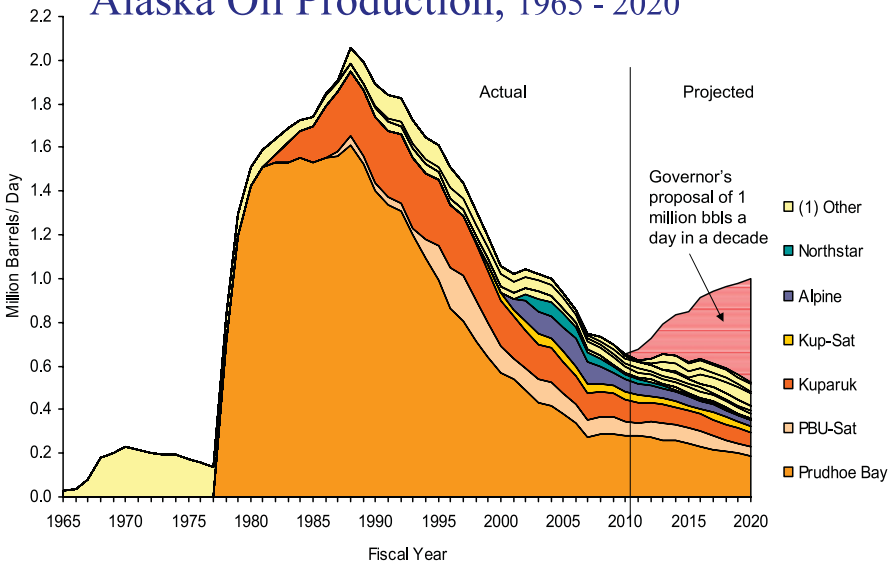
PIECES *continued from page 55*

2. Changing the game: Technology beats finding giants.

Looking in the rearview mirror at how production has matured over the first 35 years of TAPS' life may be a good reality check. But firmly planting one's eyes on the rearview mirror means a lot can be missed. In the Lower 48 new technology is already proving to be a game changer. Horizontal drilling has already made its mark on the North Slope. Roughly speaking the amount of exposure a well has to the rocks it is trying to produce from, the more production there will be. Resources spent drilling down to those rocks are wasted resources, if multiple side tracks can reach the same or a larger area. Horizontal wells are on average much more productive greatly reducing the cost per well and the cost per barrel produced.

Hydraulic fracturing or fracking is a new technology which builds on the notion of increasing the contact between the well and the area it is trying to drain. The fracturing process can be thought of as expanding the well bore into the surrounding rock through thousands of hairline factures. The process uses water under very high pressure to fracture the rock and increase the flow of hydrocarbons out of the well. Again this process also makes wells vastly more efficient: twice as productive or more than older wells.

Traditional methods typically recovered less than 50 percent of the original oil in place; the needle is shifting to above 50 percent. Rocks that couldn't produce enough oil economically using the old technologies can be exploited with the new technologies — frequently these are the lower porosity and permeable shales. It is not so much that we find another giant as that technology transforms what would have been considered uncommercial or small fields into a giant; or giants get transformed into supergiants. In the Lower 48 things are changing so quickly that no one seems to quite understand how these two technologies are going to transform the oil and gas business.



Source: Alaska Department of Revenue, Fall 2010 Revenue Sources Book.& Fall 1999 RSB, DNR 2007 Oil and Gas Report
(1) Cook Inlet, Duck Island, Milne Point, Liberty, Pt Thomson, Fiord, Nanuq, Oooguruk, Nikaitchuq and NPRA.

COURTESY DAN DICKINSON

In the world of gas, it has taken less than half a decade for "the unconventional to become the new conventional." In the Lower 48, people speak of gas coming from "gas factories" — exploration risk has all but disappeared and the focus is on technical methods of removing the vast quantities of known gas — all without spending millions of dollars to drill new vertical bores down through miles of rock hoping to find gas.

How will this play out in Alaska? Great Bear is doing a great job of articulating its plans and hopes for Alaska development of unconventional shale oil resources. Undertaking a 15-year program drilling 200 wells a year (3,000 wells total) will deliver a peak of 300,000 bpd dropping down to a steady state of 150,000 bpd. According to a presentation given to the House Resources Committee, on Feb. 18, 2011, if a year round access to drilling emerges from the Roads to Resources program so that drilling starts in 2013, a decade from now they will be producing roughly 175,000 bpd (and on a rising rather than falling curve.)

Using the Great Bear figures which were based on incentives generated through credits, the application of these new techniques may replace the need for a giant field or two (of the five required) in our quest for 1 million bpd. There are all kinds of other unconventional reserves on the North Slope — parallel technical breakthroughs might produce similar new oil flows. However, none has working and growing exemplars in the Lower 48 the way that the shale processes do.

3. Does gas in barrel-of-oil equivalents count?

What about gas making up the difference in barrel of oil equivalents? The last section touched on new technologies to exploit gas resources. As gas has become easier to produce (combined with a simultaneous macro-economic easing of demand as a result of recession) more has

been produced. The result, as any competent economist would have predicted, is that the price of natural gas has fallen. That it is not a stretch to call this phenomenon revolutionary is confirmed by the fact that simultaneously oil prices have stayed at unprecedented high levels.

Frequently in management texts one finds the notion of setting goals within constraints. If the governor really wanted TAPS to move 1 million bpd and there were no other constraints, this would be a perfect testing ground for all the rhetoric about setting the private sector free or seeing what the private sector can produce without having to carry the state's government as an operating cost. The state could announce a zero royalty rate, and exempt all production from production, income and property taxes — and do it through constitutional mechanisms that would assure investors that increased production, not revenue was Alaska's only long term goal — surly this would bring about enormous increases in investment, and eventually production. But at what cost? The state finances upwards of 90 percent of its unrestricted general fund budget from oil revenues — and oil flows without those revenues would be worse than pointless to many Alaskans.

Unfortunately, getting barrel of oil equivalents from gas could have directionally the same effect. Why? As mentioned above, the value of gas has fallen so dramatically in relation to oil. To keep the math simple, a project to export 4.2 billion cubic feet a day of gas (with a heating value of 1000 Btu per thousand cubic feet) is the energy equivalent of 700,000 bpd. Adding that production to Alaska's exports would put the state at over 1 million bpd equivalent. The bad news is that using late 2011 prices that much gas would sell for roughly $2 million a day. On the other hand, 700,000 barrels of oil would sell for almost 40 times that or $80 million a day. Here is not the place to run that through the intricacies of the state's fiscal system: suffice it to say, that at these prices the state's revenues would fall dramatically if the production shortfall were made up with gas equivalent through a gas line to the Lower 48.

4. Other People's Oil

The Chukchi and Beaufort seas are the Outer Continental Shelf, OCS, off the northern coast of Alaska which has proven phenomenally expensive — and disappointing — to explore in the past. Estimates of the potential prize are huge and explorers want to take another look. For example the National Energy Technology Laboratory published estimates for the Beaufort in the "supergiant" range of 5 billion barrels of oil, with the Chukchi even higher. Shell, for example, wants to invest billions in the area and has spent the better part of a decade in the field, before regulatory agencies and in the courts, trying to acquire all the required permits. Assume for a moment that Shell (1) works its way through all the barriers and actual explores, (2) indeed finds the equivalent of a supergiant field and (3) decides to move it to market through TAPS — all within a decade. This might well fulfill the governor's vision of a million barrels a day in TAPS. However, because the oil does not come from land which the state either owns and/or has taxing power over, the oil that we rely on for the production taxes, income taxes and royalties that pay for state government may continues to decline at a precipitous rate.

Unlike the situation with gas described above, the state can and probably would remedy that situation. Consider FY 2010 when according to the Department of Revenue, 240 million barrels of oil were produced in the state and generated $4.9 billion in unrestricted oil revenues. Roughly $4.8 billion or $20 dollars a barrel came from production taxes, income taxes and royalties, while 50 cents a barrel came from property taxes — practically all of that from taxes on TAPS as it passed through the unorganized land outside of the North Star, North Slope and Valdez boroughs.

If TAPS is filled mostly with non Alaskan-produced oil, then the remedy from the state's point of view would be to shift its taxing strategy away from production tax and toward a tax on TAPS. The Alaska Department of Revenue currently forecasts the TAPS tariff to rise from about $4 a barrel to something close to $6 a barrel a decade from now (coupled with a continuing decline in throughputs.) Simply adding OCS barrels to the mix should drive the per barrel cost of running the pipeline downwards. On the other hand the state might make the pipeline tariff more like cigarettes today — where more than half the purchase price goes to taxes. Tobacco Free Kids reports that Anchorage has the third highest combined state and local cigarette taxes in the nation, and there is no reason to think Alaska would not have a similar view toward TAPS. A million barrels a day through TAPS with each barrel paying $6 in state taxes would generate over $2 billion a year, which would make up for a lot of foregone production taxes and royalties.

This would be a dramatic example of changing tax policy and that leads to the current day and the current debate in the legislature and the actual implementation one of the governor's five planks: fiscal reform.

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PIECES *continued from page 57*

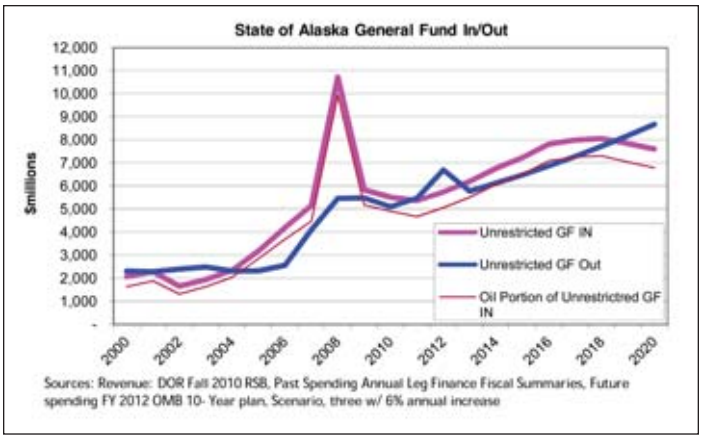
5. Beyond hope and hype — actually delivering investment deals

Economists point out that, all other things being equal, the less something is taxed the more of it will be produced, and the more it is taxed the less that will be produced. On Alaska's North Slope that approach can be tricky — it is not a closed system where incremental dollars earned from selling North Slope oil can either go to the state's capital budget or go to the lease holders' capital investment budget. Just as the initial investments in Alaska's oil production were funded by profits generated elsewhere in the world, as Alaska matures disinvestment can occur and the profits generated and not taxed away here can go to fund investments in other parts of the world

We can contrast two views of government's role: in one the government creates the environment and investment climate it wants, and hopes for the best outcomes over time. If it is not getting enough investment it moderates the tax take in favor of investors. Or it may test in the opposite direction and see the effect of increased tax on investment.

The alternative approach derides this passivity, and argues that Alaskans, acting through state government, need to more actively develop these resources. Alaska should take risks proportional to its rewards.

Being more practical than ideological, of course the state's actual policies blend — or muddle — these two ideas. For example Alaska currently sets taxes and hopes it will attract sufficient investment. However, any fine tuning with the fiscal environment in investors favor is viewed by some as a "give-



away" unless the state receives guarantees and promises from the industry for more investment. Of course promises and guarantees are the language of contracts. In the world of contracts, a promise is only extracted in exchange for another promise. In short it leads the state to the opposite philosophy of government driving development: by making mutual promises with investors. If the investor promises to invest, the state promises to set limits on its take from the investment.

Politically there has been a great deal of confusion surrounding these efforts at mutual promises — both the Stranded Gas Development Act under the Knowles and Murkowski administrations and the Alaska Gasline Inducement Act under the Palin and Parnell administrations have experimented with this latter managed policy — so far to little effect, generally because while politicians feel quite comfortable asking for guarantees and promises from putative investors, the state has proven quite unwilling to make broad promises about future revenue streams.

To achieve the kind of significant production growth envisioned by the governor, we will probably need both to lower the high incremental rates associated with progressivity — and assure potential investors that the lower rates will remain in place after the investments have taken place.

There are at least two ways of doing this — both probably requiring constitutional amendments. Section 9.1 of the Alaska constitution states that "The power of taxation shall never be surrendered. This power shall not be suspended or contracted away, except as provided in this article." The people of the state could take the constitution's authors up on their challenge and enumerate the conditions under which that precious power of taxation would be temporarily suspended or contracted away: what kind of promise and performance would an investor have to undertake before being promised some kind of fiscal stability.

The second would be to erase the notion that the oil industry is responsible for keeping the state in whatever style it becomes accustomed to. Despite a spending (appropriation) limit in Section 9.16 of the Alaska constitution — according to figures from Legislative Finance Division, it took just three years of increasing revenues between 2005 and 2008 for governors Murkowski and Palin to double Alaska's general fund, GF, spending from $2.6 billion up to $5.5 billion. In the four years since then governors Palin and Parnell oversaw continuing increases that put the 2012 unrestricted GF budget at $6.7 billion. Putative investors are going to be very concerned where Alaska's politicians and voters will turn to sustain that kind of spending

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Van Meurs critical of ACES, HB 110

Global oil expert outlines flaws in current tax, says governor's bill won't fix problems

By STEFAN MILKOWSKI
For Petroleum News, Oct. 30, 2011

When state lawmakers resume discussions of oil and gas policy this winter, they'll have one tool they didn't have last year — a suite of reports by global oil expert Pedro van Meurs.

Van Meurs, who advised former Gov. Frank Murkowski, is compiling six hefty reports on oil and gas jurisdictions around the world with help from PFC Energy and Rodgers Oil & Gas Consulting. Alaska is discussed in the third report, which covers oil and gas jurisdictions in the Arctic. The sixth report, a summary report, is due out early next year.


JUDY PATRICK
PEDRO **VAN MEURS**

The Legislative Budget and Audit Committee purchased the reports, along with a database compiled by the energy research firm Wood Mackenzie, in late 2010. The Van Meurs Corp. has granted limited-time access to its reports to news organizations, including Petroleum News.

Van Meurs finds ACES, HB 110 flawed

Van Meurs is critical both of the current tax, dubbed Alaska's Clear and Equitable Share, and of Gov. Sean Parnell's proposal to fix it.

Van Meurs describes Alaska as one of a few Arctic jurisdictions that combine high taxes with generous incentives. (Other jurisdictions tax at a lower rate, but offer less support up front.) Among the 37 Arctic oil tax regimes van Meurs considers, Alaska is grouped in the middle, given three stars out of five in terms of attractiveness from an investor standpoint.

But van Meurs contends that Alaska's system is too extreme. The highly progressive tax limits companies' returns at high oil prices and, combined with high tax credits, can result in state support for developments nearing or even exceeding 100 percent, giving companies little incentive to reduce costs.

Despite the generous credits, van Meurs argues that Alaska doesn't do enough to incentivize the two commodities that could boost state revenues and ensure a long-term future for the North Slope: heavy oil and natural gas.

He adds that setting the progressivity surcharge based on the combined price of oil and gas (on a barrel-of-oil equivalent basis) will likely result in paltry or even negative incremental revenue for the state when North Slope gas is developed. Van Meurs advocates separating the tax on gas from that on oil — "decoupling" — but adds that the tax rate for gas would then have to be reduced.

Van Meurs writes that Gov. Sean Parnell's HB 110, a modified version of which passed the House last session, and HB 17 by Rep. Mike Hawker, would indeed increase returns for producers, but would not address the flaws in the current tax.

The governor's proposal to offer a lower rate for new fields could actually be counterproductive because it would force those developments to be taxed separately — to be "ringfenced" — while other developments can be written off existing production elsewhere in the state.

Editor's note: Read the rest of the story, which contains a reaction from lawmakers and the Alaska Department of Revenue, as well as comments about Alaska's proposed gas pipeline from the North Slope, at http://bit.ly/tW7Sxm.

Dermot Cole on Van Meurs report

In the Dec. 8 edition of the Fairbanks Daily News-Miner, Dermot Cole reviewed what Pedro Van Meurs had to say in his Arctic report dealing with Alaska, in "International oil consultant says Alaska tax rates 'not particularly out of line' with other regions," which can be found online at http://bit.ly/vwrLsJ.

At the end of Cole's review, he writes, "The comments by Van Meurs are the latest evidence that the state Senate was correct in delaying action on the governor's oil tax reduction plan as there are many aspects of the tax cut bill that have not been thoroughly reviewed."

—Kay Cashman

PIECES *continued from page 57*

in the face of either falling production or price correction.

Investors might be reassured if instead Alaska moved more toward the Norwegian Model: treat all oil and gas revenues as incremental and set them aside, only to be drawn on through a restrictive formula.

Alaskan voters have focused on this part of the constitution amending it in 1976 by adding Article 15 — the Alaska Permanent Fund, in 1982 adding the Appropriation limit mentioned above and in 1990 adding the Article 17 — the Budget Reserve Fund. Perhaps what is needed now is an amendment that puts all oil and gas revenues into the Budget Reserve Fund (or a successor fund) and then limits the rates at which that fund could be drawn down and used to fund government operations. In other words, provide an investor with the knowledge that the current year budget shortfalls would not be balanced by increasing taxes on oil and gas projects.

Conclusion

How likely is that the state can turn a 100 bpd of decline into 100 bpd of growth? Pointing out some of the barriers to achieving that kind of growth may lower unreasonable expectations. It will not be pretty if the citizens of Alaska are led to believe that they are poised on the brink of an additional 100 bpd going into TAPS every day for the next decade. If that kind of growth doesn't occur, it would be unfortunate if the blame fell on those companies that did invest and produce more oil in Alaska. The paths to reach a million bpd over the next decade are difficult ones.

Make Alaska competitive group vocal

By PETROLEUM NEWS

Although the Anchorage-based Make Alaska Competitive Coalition, or MACC, is one of the most outspoken proponents of a reduction in Alaska's oil production tax, it does not accept funds from oil producers.

It's a grassroots organization made up of individuals, businesses, community and civic organizations from across Alaska. The coalition's purpose is to "provide a unified voice to Alaskans who understand a strong business climate is essential for Alaska's economic future."

According to its website, http://www.makealaskacompetitive.com/, MACC's steering committee is made up of the following individuals:

Will Anderson, Koniag Inc.
Rick Boyles, Teamsters Local 959
Carl Brady, Brady Inc.
Judy Brady
Margie Brown, CIRI
Bill Corbus, Alaska Energy and Resources
Cynthia Henry, Hops Hallmark
Jim Jansen, Lynden
Tony Knowles, Governor
Marc Langland, Northrim Bank
Tom Maloney, CH2M Hill
Harry McDonald, Carlile Transportation Systems
Bill Moran, FirstBank
Gail Phillips
Norm Phillips, Jr.
Ed Rasmuson
Rex Rock, Arctic Slope Regional Corporation
Marilyn Romano, Alaska Airlines
Helvi Sandvik, NANA Development Corporation
Bill Sheffield, Governor
Richard Wien, Florcraft

MACC's mission is "To inform Alaskans about issues that impact our economy so Alaska remains a premier place for business opportunities now and for future generations."

Print ads from Make Alaska Competitive Coalition, which accepts no funds from oil companies.

On the coalition's Home page is a brief editorial titled, Our Economic Driver is in Decline."

It reads as follows

"Alaska has a production problem — one that won't be fixed by increased exploration drilling. "The pipeline is only a quarter full and the best way to keep it operating is to develop the billions of barrels of reserves in the legacy fields, like Prudhoe Bay, Alpine and Kuparuk.

"The oil is there but it will cost millions and millions of new capital to produce it. And that's why ACES (Alaska's Clear and Equitable Share) must be fixed.

"While exploration is vital to the long-term, developing the existing reserves is critical to keeping Alaska healthy in the near and mid-term. And those reserves fall under the production side of ACES.

"ACES offers generous incentives for exploration — and punish-

ing disincentives for production, especially when oil prices are high.

"Alaska figured out the exploration side of the tax equation. We now need to balance the production side.

"MACC accepts no money from oil producers."

Presentations, promises

One of the most interesting sections of its website are the presentations, including those from top executives of BP and ConocoPhillips, promising increased investment if Alaska's oil and gas production tax law, commonly referred to as ACES, is changed.

Among the presentations is an April 2011 speech from former Gov. Tony Knowles, who combines a bit of personal and Alaska history with his support for reduced production taxes.

In regard to Knowles' Fact #2, information about the 2011-12 exploration drilling plans of eight companies on Alaska's North Slope were not yet public in April 2011, when Knowles made this speech.

Knowles urges change

"In 1968, after school and the Army, I was working on an oil rig in California. My employer had drilled the Prudhoe Bay discovery well and offered me a job in Alaska. Just married, Susan and I came to Alaska with the chance to live the American dream — thanks to a new state that believed in creating jobs and the private companies that took the risk of investing for development. It was exciting, and my family and I will always be profoundly grateful to the people who gave us this chance.

"And those dreams can be as real today as they have been to the thousands of Alaskans who discovered the oil, built the pipeline, and developed the nation's largest fields. Tens of thousands of jobs, new Alaska businesses and a growing Permanent Fund have touched the lives of Alaskans in every part of our state. That's why I have joined the groundswell of support calling for our leaders to heed the warning signs of a much harsher, not too distant future and take the necessary steps to make Alaska competitive.


TONY **KNOWLES**

"Some people are saying that times are good and revenues are up. They miss the point. The issue is not about today but what are we doing today to ensure tomorrow's prosperity. To ignore the facts we know today, while we enjoy yesterday's wisdom, is to steal from our children's future.

The facts are not in dispute.

Fact #1: The yearly 6 percent decline in the volume of oil flowing in the pipeline which today is only about 30 percent full cannot continue without dangerous consequences to Alaska's economy.

Fact #2: According to the AOGCC and the DOR, exploration drilling activity has decreased from approximately 17 wells just three years ago to only four wells in 2010. These exploration wells indicate the level of interest in looking for the new discoveries that are essential to increasing the oil flow from new fields. With only one exploration well being drilled on the North Slope in the 2011 exploration season, we now have the lowest exploration drilling on Alaska's North Slope since the discovery of Prudhoe Bay 44 years ago.

Fact #3: The AOGCC data also illustrates that it takes an average of 11 years to move a discovery to first production. We must do something before it's too late.

Fact #4: Investment in exploration by an oil company is competitively based upon the total business environment. This includes the physical cost of exploration, development, and production as well as the taxes paid to local, state, and federal governments.

Fact #5: With lower costs and lower total government take, the oil industry in Canada and the Lower 48 is on fire with new exploration, drilling activity, and new production generating new jobs and a booming economy. The Lower 48 has been able to increase oil production the last few years while Alaska continues to decline at 6 percent a year.

It shouldn't be hard to connect the dots. While we don't control the costs of operating in a remote arctic environment, we do control the tax regime.

The status quo is not acceptable. There is no time to lose.

It cannot be a partisan political issue. In reality it is just a straightforward business decision to create the long term partnership of shared commitment and responsibilities that encourages growth. This has happened before.

Faced in 1998 with the price of oil reaching $9 a barrel and struggling with serious budget cuts, the Legislature and the executive branch worked together across party lines — and with industry — creating marginal field tax incentives and new agreements on old undeveloped leases, opening new state and federal land for exploration, and reducing exploration regulations.

Despite the gloom of low prices there was a shared spirit of optimism with the surge of investment, exploration, and production, which created new Alaskan jobs and businesses.

All of this inspired ARCO to coin the slogan "no decline after 99".

And, in fact, these policies — and the investment of the oil companies — put more oil in the pipeline and reversed, for the first time in more than a decade, the declining "Prudhoe Bay curve".

We know it can be done.

These results defied the conventional wisdom of the time that said with low oil prices tax, incentives and new investments could never happen.

With reduced budgets and services how could a state strapped for revenues offer incentives? And faced with current operating losses and an uncertain future how could the oil companies make significant new capital investments?

It was thought that agreements would happen only in times of prosperity with plentiful tax revenues and corporate profits, when parties could comfortably plan for the long range. However scarcity brings about a sense of urgency that sharpens the focus and gets results.

In the mid and late 90s Alaskans came together — urban and rural — Democrat and Republican — business and labor — to face the pending financial disaster without being afraid to do what needed to be done.

We now know that in the comfort of surplus revenues and high profits it is tempting to side step the warnings of declining exploration and throughput, while ignoring the fast train approaching from the other end of the tunnel.

How do we get back on track?

We know the formula: Tough, fair negotiations; commitments by both sides; an attitude of mutual respect guided by "trust but verify"; a tax system that provides balanced returns and fair incentives to all fields including new fields, but also legacy fields; and opening new state and federal exploration areas.

We know the status quo business as usual is not acceptable. The pipeline is already running on empty. Without change, it will run dry.

We need to act today to ensure tomorrow's prosperity. Let's make Alaska competitive.

Wielechowski says ACES working

Anchorage Democrat cites profits, jobs, investment, expenditures, Great Bear, Repsol

By STEVE QUINN
For Petroleum New, May 8, 2011

When it comes to the prospects of changing Alaska's oil tax laws, Sen. Bill Wielechowski has a pretty simple response: Leave it alone.

The Anchorage Democrat serves as a member of the Senate Resources Committee and is loath to change Alaska's Clear and Equitable Share, ACES, less than four years after it's been put into place.


BILL WIELECHOWSKI

Gov. Sean Parnell's tax plan, House Bill 110, has passed the House, but went nowhere in the Senate during the first regular session of this two-year legislative term.

Currently in a special session to work out differences with the capital budget, the Legislature will leave the tax bills for another time.

Still, Wielechowski took an afternoon to present his argument before the Senate Judiciary Committee.

He titled the presentation, "Is ACES Working?"

After the hearing, he sat down with Petroleum News and stated his case.

PETROLEUM NEWS: The title of your presentation is, "Is ACES Working?" Is it?

WIELECHOWSKI: I think it is if you look at a number of different methods. Clearly we have companies making very strong profits. We have jobs at an all-time high under ACES; we have capital investment and expenditures at an all-time high since ACES passed. We have many more companies doing business in the state of Alaska. If you look at the facts of the various metrics, it's hard to say it's not working by those metrics: We are doing very well.

PETROLEUM NEWS: One of the prevailing arguments by those who want a change is that it's not enough to provide a profitable environment and you have to provide a competitive environment.

WIELECHOWSKI: When a company takes out a lease, then it is obligated to produce and explore when that lease is profitable. That's the duty to produce. It's very clear that duty exists in the State of Alaska. I don't know that the tax rates in other countries and other states are relevant because the company has a duty to produce. When you look at the rates of return, what we've calculated under ACES seem to be very good rates of return. When you look at the profit numbers, you see ConocoPhillips making $549 million in the first quarter, but you also see they generate only roughly 12 percent of their worldwide exploration and production output from Alaska yet they are generating 28 to 30 worldwide exploration and production profit out of Alaska. When you look at the metrics, the metrics show the company makes very good profits so they should be making investments. When you look at the tax rates and government takes in other countries, you'll see there are investments from companies who do business in Alaska to where the tax rates are much higher.

Libya for instance 95 percent; Russia 90-plus percent; Venezuela 90-plus percent, Conoco no longer does business there because their assets were expropriated; Ecuador, tax rate is 85 plus percent, companies are no longer doing business there because their assets were expropriated; Iraq, tax rate of 98 to 99 percent. Norway has an effective tax rate of 78 to 81 percent, so when you compare Alaska to other parts of the world where the majors are doing business, you see Alaska is very completive.

PETROLEUM NEWS: Norway is also a different system. It's not nationalized the way Venezuela and others are.

WIELECHOWSKI: Basically they tax in two different ways. One is a 50 percent tax; the other is a 28 percent tax and they are stacked on top of each other. When we were debating ACES, Norway, we consistently heard (was the country) that we should be comparing ourselves to. That was by Gaffney & Cline, the consultants the Parnell administration is using right now. When you look internationally, our tax rates are very competitive.

PETROLEUM NEWS: Everybody seems to agree on one thing, the need to put more oil in the pipeline. How do you achieve that?

WIELECHOWSKI: The thing to remember is we had a 20-plus year experiment, the old Economic Limit Factor, where you had tax rates of 12.25 to15 percent of the gross, but those tax rates only applied to the large fields, the legacy fields: Kuparuk, Alpine, Prudhoe. The satellite fields had zero percent tax rates. All the tax rates were set to decline to zero percent. Prudhoe Bay rate in 2006 was little north of 12.5 percent. In 2006, you had 15 out of 19 fields in the North Slope paying zero percent taxes. During the 20-year period you saw an annual decline of 6 percent, so the tax structure has little to do with whether a company will invest. It has something to do with it, but I don't think — it's not a be-all end-all. In fact the No. 1 thing we've heard consistently over the years is the most important thing companies look for — it's the rocks, the geology of the field. We know the North Slope is a prolific hydrocarbon basin. So how do you get more oil in the pipeline? Fortunately, based on our tax structure, we have a couple of major new developments just this year. We have Repsol who has agreed to come in and spend $768 million on exploration and development. That's a significant new entrant. You have Great Bear who acquired 500,000 acres and believes there is enough shale oil on the North Slope that they can put in 1 million barrels of oil a day. Even if they are half right, that's virtually doubling our oil production right now from where it is. So I think good things are happening. Increased competition on the North Slope is a great thing; it's probably the best things we were able to do under ACES, to increase the number of competitors. You've got to keep one thing in mind: We are financing the vast majority of the development

continued on next page

WIELECHOWSKI *continued from page 62*

and exploration on the North Slope. With a new entrant, the state picks up 65 percent of the exploration costs; with an existing producer, the state picks up 76 percent of the investment cost. The state is the largest investor on the North Slope. The Parnell administration, their fall forecast, their decline rate will be down from 5 or 6 percent per year to about 2 percent a year in the next seven or eight years. I think you will see a stem in the decline, and that doesn't include Repsol and Great Bear.

PETROLEUM NEWS: If there is anything that needs changing in the tax program, what is it?

WIELECHOWSKI: I think ACES is working. It's designed in a way that encourages new entrants; it encourages new exploration; it encourages reinvestment in legacy fields. So I think it's working. Are there changes that could be made? The one big thing the executive branch could do to put more oil in the pipeline right now is start enforcing the leases. We heard (ConocoPhillips CEO) Jim Mulva say if we pass HB 110 they will spend $5 billion they believe will generate 90,000 barrels a day. We looked at those numbers under ACES and by our analysis that's an extremely profitable project. It should generate about $3 billion in profit. It's also a project that generates a rate of return over about 95 percent. Those numbers have not been refuted by the administration. In fact they looked at the numbers and said they are about right. With that knowledge, why isn't the governor saying, 'why aren't you developing those fields now instead of waiting for billions of dollars in tax breaks?' That's the No. 1 thing we could be doing now: strictly enforcing those leases. … At some point the State of Alaska is going to need to say if the leaseholders … on the North Slope aren't going to develop their leases, we'll take the leases back, and we'll either re-bid them or we'll do them ourselves.

PETROLEUM NEWS: That could mean years in court. Just look at Point Thomson.

WIELECHOWSKI: Point Thomson is a good example. We waited 30 years for Exxon to develop Point Thomson. It wasn't until Frank Murkowski began the process of taking way the leases that Exxon spent $1 billion. Sometimes the state has to exercise its sovereign right and say either you drill or we will.

Editor's note: Questions and answers were removed that were not related to ACES. To read the full article from the May 8, 2011 issue of Petroleum News go here http://bit.ly/vsltfS.

UNTAPPED CRUDE *continued from page 41*

duction at 900 bpd.

Savant steps in

In 2008, BP entered into an agreement with Denver-based Savant to bring Badami back into production using horizontal well technology and possibly advanced hydraulic fracturing techniques. Savant and its minority partner ASRC Exploration agreed to drill two wells in the unit as part of a deal that would eventually give them working interest in key leases and leave BP with an overriding royalty interest. One of the wells was an exploration well in the untested Red Wolf satellite, and the other a new horizontal sidetrack to one of the original vertical producing wells in the unit.

Both wells were drilled and Badami went back online in November 2010.

Production is currently at around 1,000 barrels a day, with a goal up 4,000 barrels.

Savant recently assumed operatorship of the unit.

Close to settling

Even if Savant is not successful at keeping the Badami unit online, the Badami pipeline would likely be available to transport 10,000 barrels of oil and natural gas condensate starting in 2015-16 from the Point Thomson unit, which has several leases that run along the Staines River next to ANWR's 1002 area.

Too long of a story to tell here, basically the Point Thomson unit was formed in 1977 and is currently bound up in a court fight with the State of Alaska, which is trying to break up the unit and reclaim the acreage.

But even as the legal struggle continues, lawyers for the state and the leaseholders are reportedly drawing close to a settlement — a settlement that will require operator ExxonMobil to finish developing phase one of its 10,000 bpd oil and condensate development, which includes a common carrier 70,000 barrel-per-day liquids pipeline to Badami.

ExxonMobil has drilled two of five proposed wells for Point Thomson and is awaiting permit approval to proceed with the project.

There are numerous prospects that have been drilled on and offshore the eastern North Slope, but none are big enough to justify a pipeline to Badami, even though Red Dog is estimated to contain 45-85 million (P-50) barrels of recoverable oil, and BP estimated Slugger contained some 280 million barrels of oil in place, just before it stopped exploring in Alaska.

Per Donkel Oil & Gas, operator of some of the Stinson prospect leases north of the 1002 area, quotes 150 million barrels probable recoverable oil within a single 100-foot thick sand.

Yukon Gold, operated by Savant and adjacent to ANWR's 1002 area, has recoverable reserves of 120 million barrels of oil, per the state of Alaska.

The list of eastern North Slope prospects goes on.

Although they are in federal, not state waters, Shell is hoping to drill up to two Beaufort wells in the open water season of 2012, with or without the Point Thomson pipeline, including its most well-known prospect, Sivulliq, formerly named Hammerhead.

Optimistic about the long term

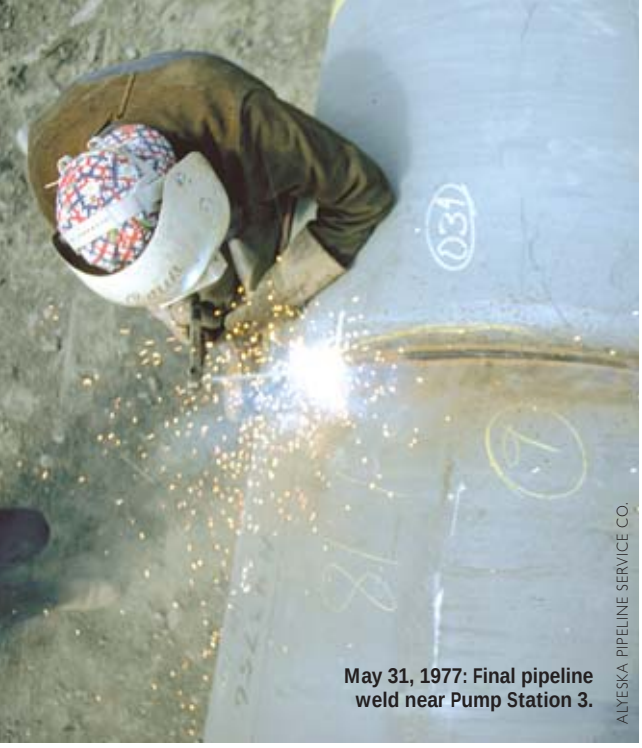
Myers feels optimistic about the long-term future of the oil industry in northern Alaska.

"I think we'll see just a tremendous amount more oil produced, especially from the stratigraphic plays over time," he said. "I think someone will stumble into that 500 million to a billion barrel field size."

And where is that next big find on state acreage?

In 2005, Myers said, "In the long term if I were to bet on a big prospect, the Brookian stratigraphic plays are where I'd put my money."

In 2011, he also included oil from North Slope source rocks, most of which are shale.



ALYESKA PIPELINE SERVICE CO.

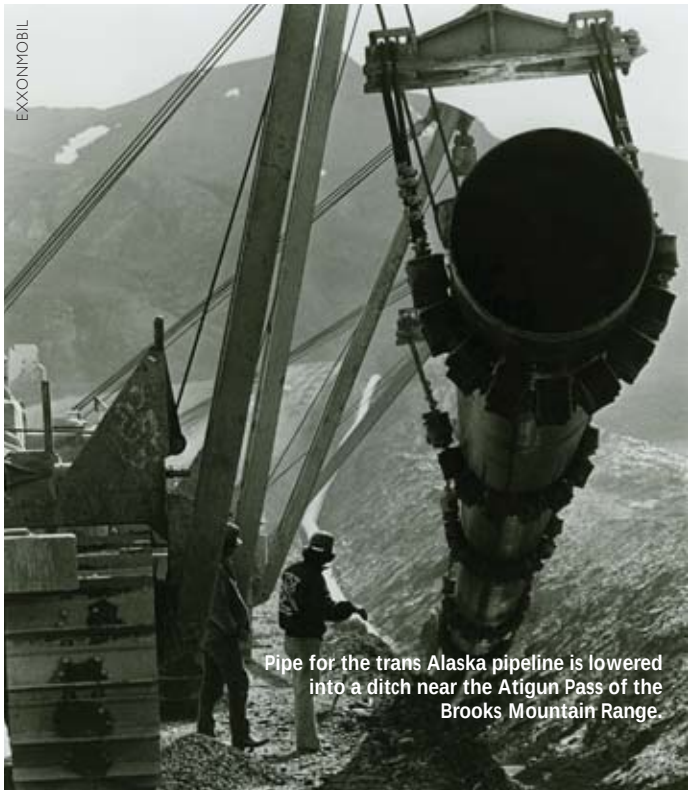
May 31, 1977: Final pipeline weld near Pump Station 3.

Taking Alaska's oil to market

The 800-mile-long Trans Alaska Pipeline System, or TAPS, is one of the world's largest pipeline systems. Starting in Prudhoe Bay on Alaska's North Slope, TAPS stretches through rugged and beautiful terrain to Valdez, the northernmost ice-free port in North America. Since pipeline startup in 1977, TAPS operator Alyeska Pipeline Service Co. has successfully transported more than 16 billion barrels of oil. The average number of barrels pumped daily from Pump Station 1 in November 2011, per Alyeska, was 625,336. The year-to-date daily average was 579,171 barrels.

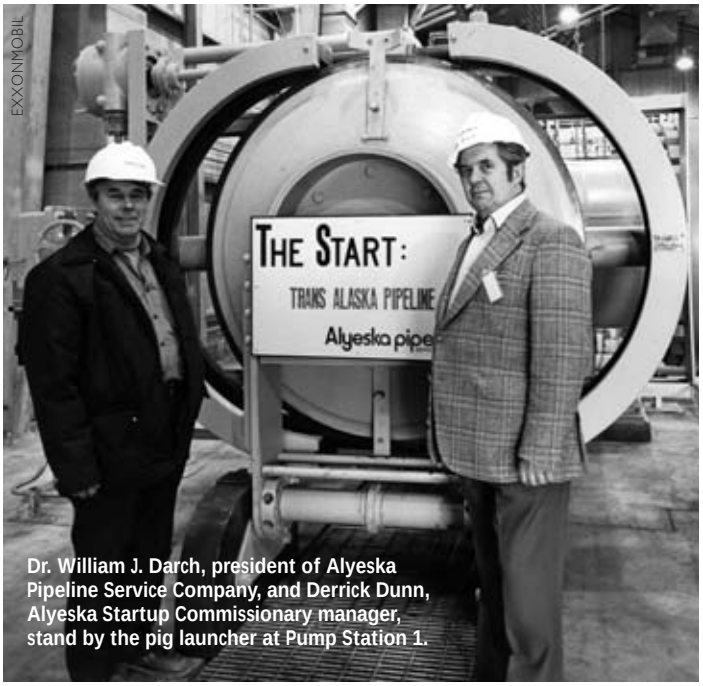
GIL MULL

An aerial view of the bridge built over the Yukon River for the trans-Alaska oil pipeline and Haul Road crossing during its construction in the summer of 1975, with big barges and construction cranes in the center of the river.



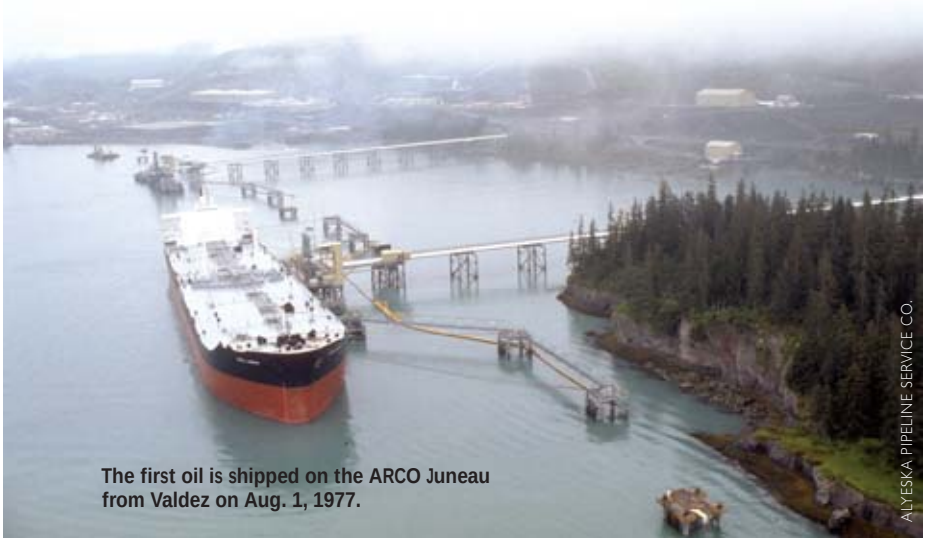
EXXONMOBIL

Pipe for the trans Alaska pipeline is lowered into a ditch near the Atigun Pass of the Brooks Mountain Range.



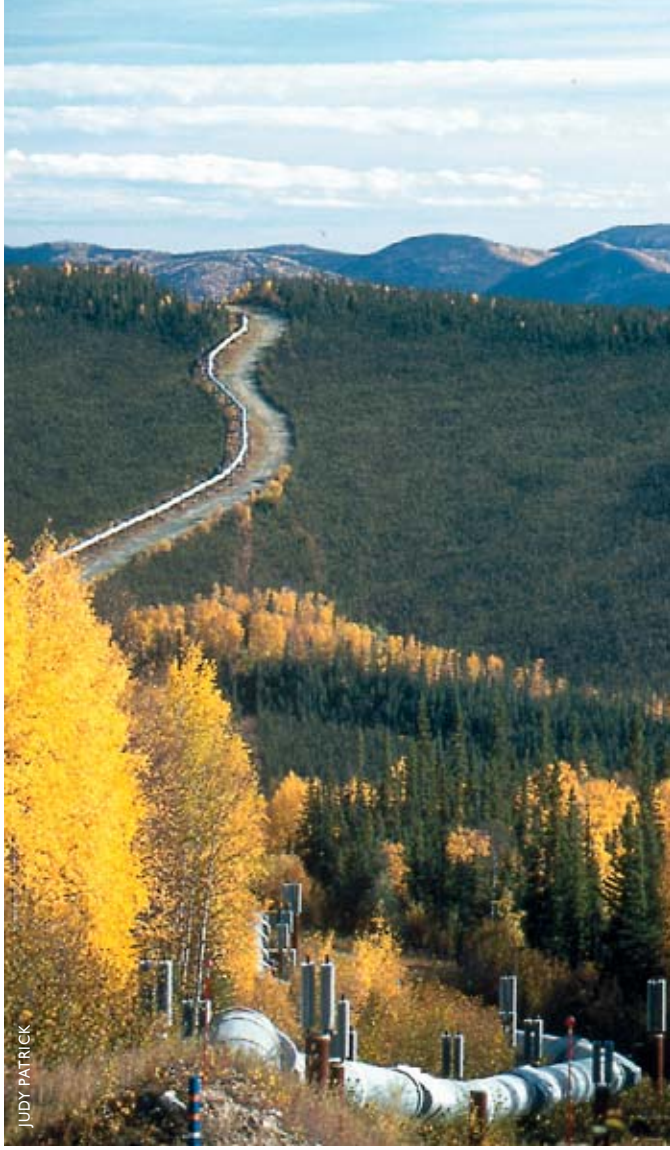
EXXONMOBIL

Dr. William J. Darch, president of Alyeska Pipeline Service Company, and Derrick Dunn, Alyeska Startup Commissionary manager, stand by the pig launcher at Pump Station 1.

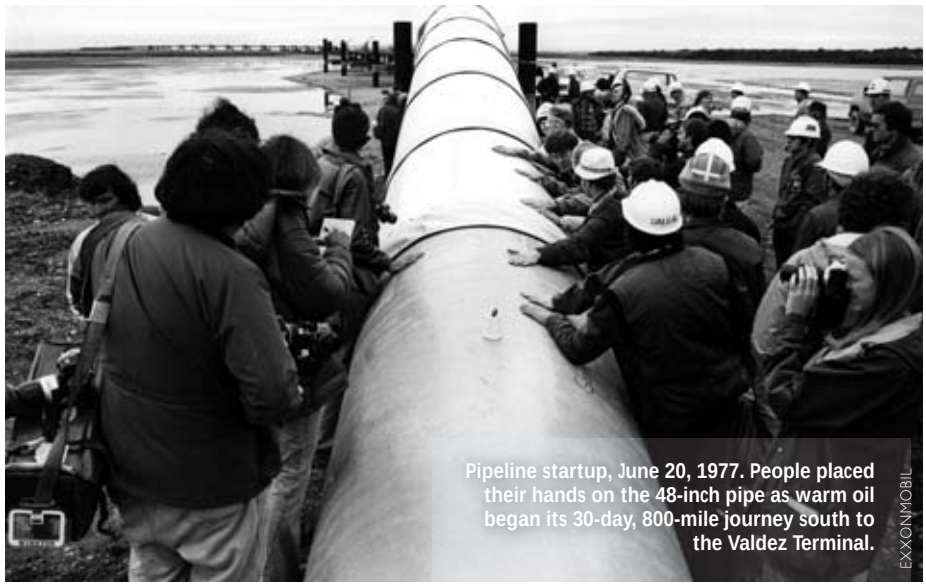


The first oil is shipped on the ARCO Juneau from Valdez on Aug. 1, 1977.

ALYESKA PIPELINE SERVICE CO.



JUDY PATRICK



Pipeline startup, June 20, 1977. People placed their hands on the 48-inch pipe as warm oil began its 30-day, 800-mile journey south to the Valdez Terminal.

EXXONMOBIL

An aerial photograph of Pump Sation 1, taken in 2010.

ALYESKA PIPELINE SERVICE CO.

JUDY PATRICK

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