2/16/11 OVERVIEW: ALASKA OIL AND GAS PRODUCERS

<TARGET><BILL></BILL><SUBJECT>2-16-11 OVERVIEW ALASKA OIL AND GAS PRODUCERS</SUBJECT><COMM>HRES27</COMM></TARGET>

Alaska Oil & Gas Association
Testimony to the
House Resources Committee
on
House Bill 110

Marilyn Crockett
AOGA Executive Director
February 16, 2011

AOGA

Looking Ahead

AOGA Member Companies

PIONEER
NATURAL RESOURCES

Anadarko
Petroleum Corporation

XTO
ENERGY

MARATHON

Statoil

ExxonMobil

Apache

TESORO

PETRO STAR INC.
EXCELLENCE IN ENERGY

bp

Alyeska pipeline
SERVICE COMPANY

eni
petroleum

Chevron

FLINT HILLS
RESOURCES
Alaska

What is AOGA?

Alaska's oil and gas trade association since 1966

- Purpose

  1) Serve as a single point of contact for Alaskans on the state's oil and gas industry

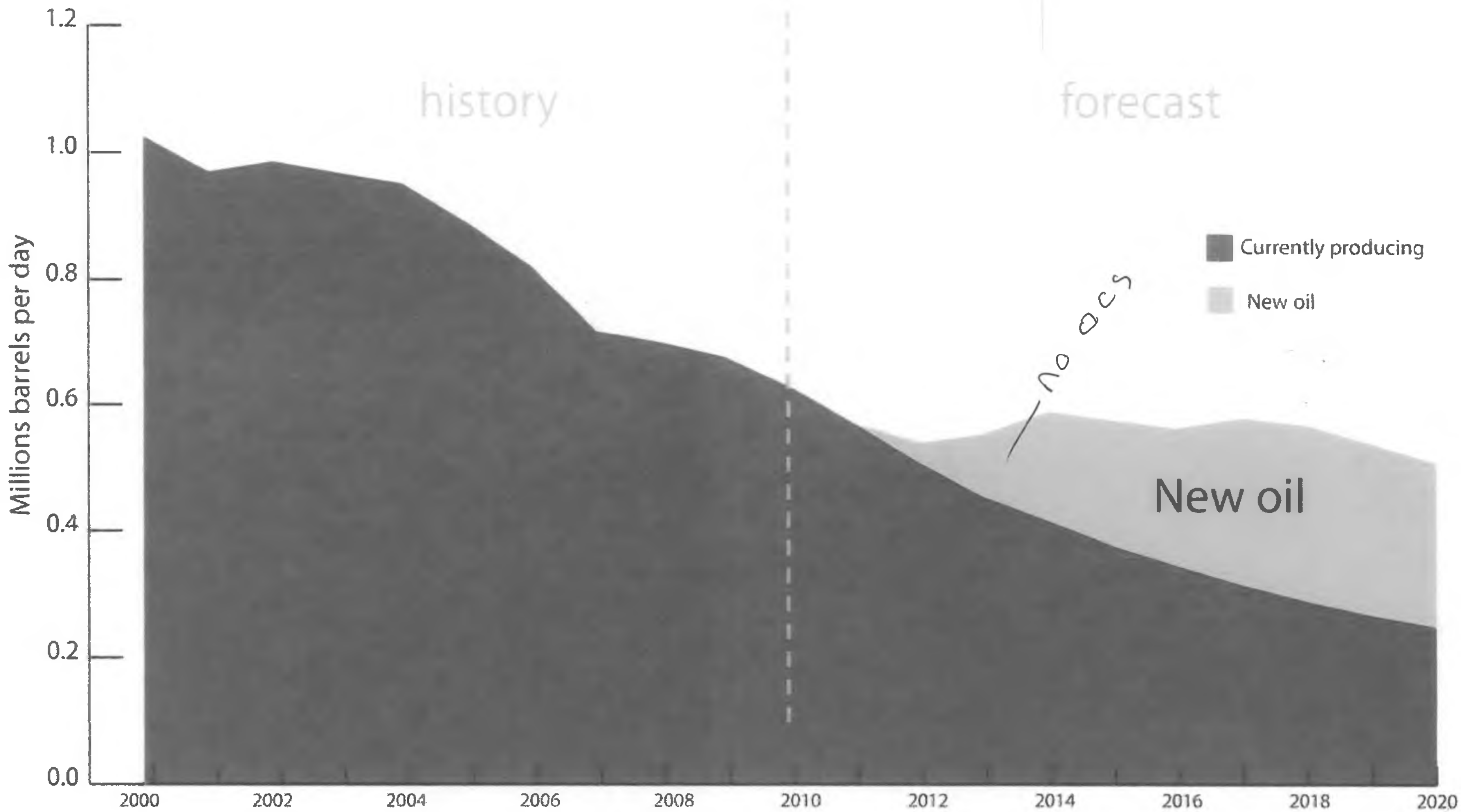
  2) Provide a forum for discussion and a point of decision on issues that affect the industry

- Goal

  A vital oil and gas industry that contributes to a vibrant economy for Alaska

Alaska North Slope Production

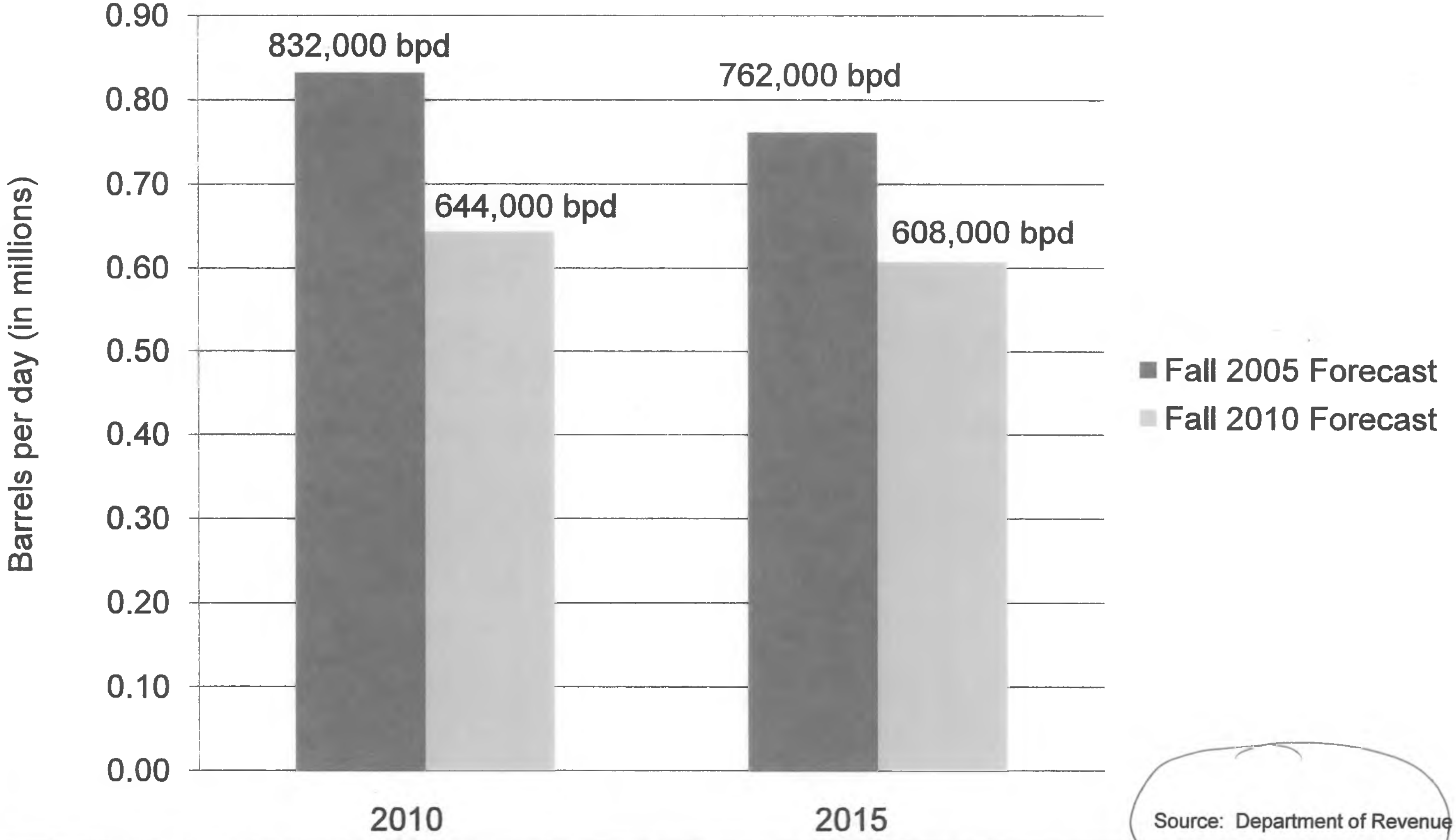
FY 2000-2010 and Forecasted FY 2011-2020



Source: Department of Revenue – Dec. 2010

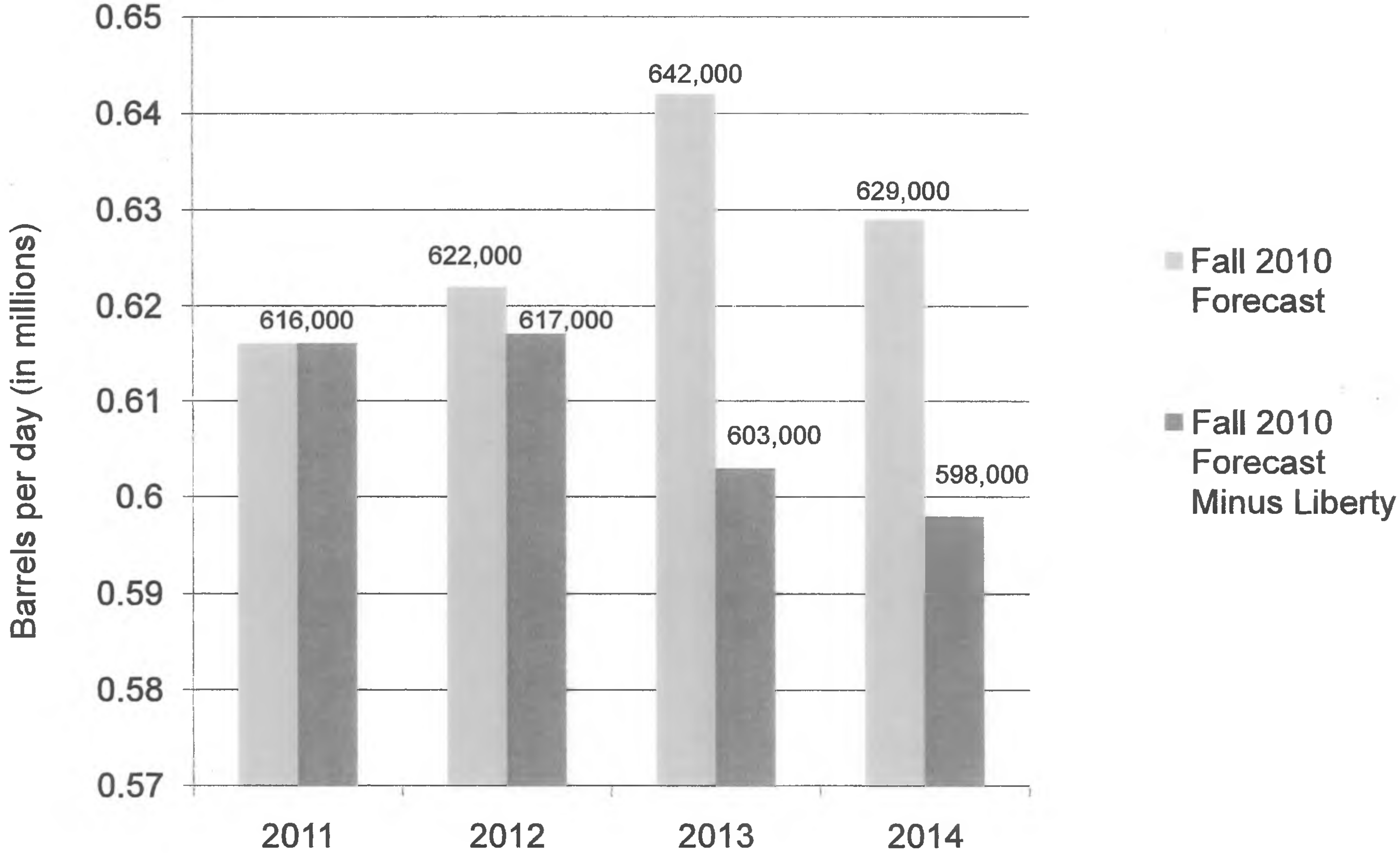
AOGA Looking Ahead

Forecast is down 20% from Five Years Ago



Source: Department of Revenue

Current Forecast Will be Off



Source: Department of Revenue

Important Production Facts

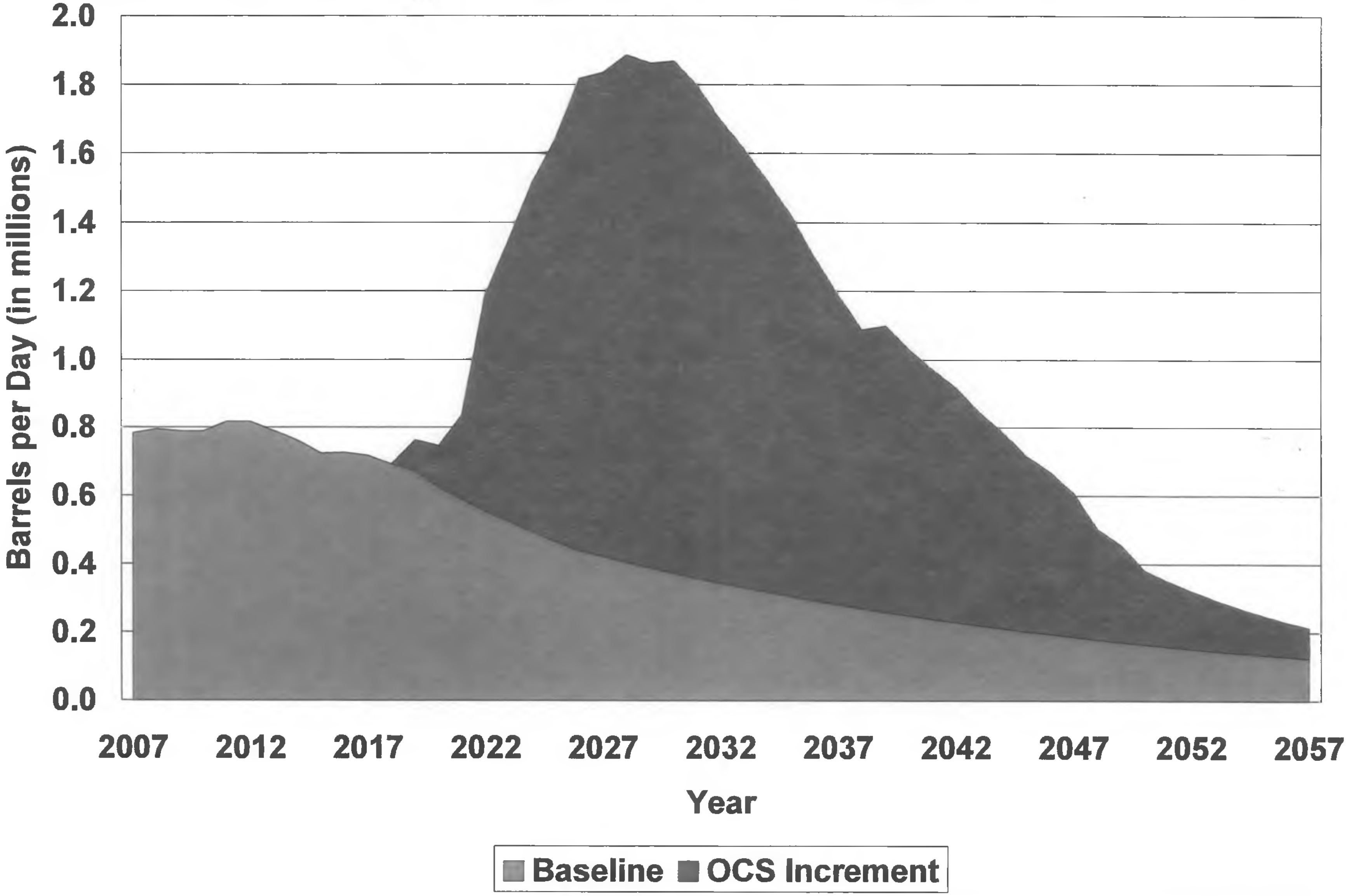
- In 10 years, the State forecasts half of Alaska's production will be from "New Oil".

- Even with this new oil, the State is forecasting production will decline by 124,000 bpd in 10 years.

- 98% of the production in 2020 will be from oilfields located in current unit boundaries.

- Legacy fields continue to dominate production forecast as Prudhoe and Kuparuk will still provide 63% of production in 2020 – so new oil is forecasted to come from legacy fields too.

North Slope Oil Production With OCS

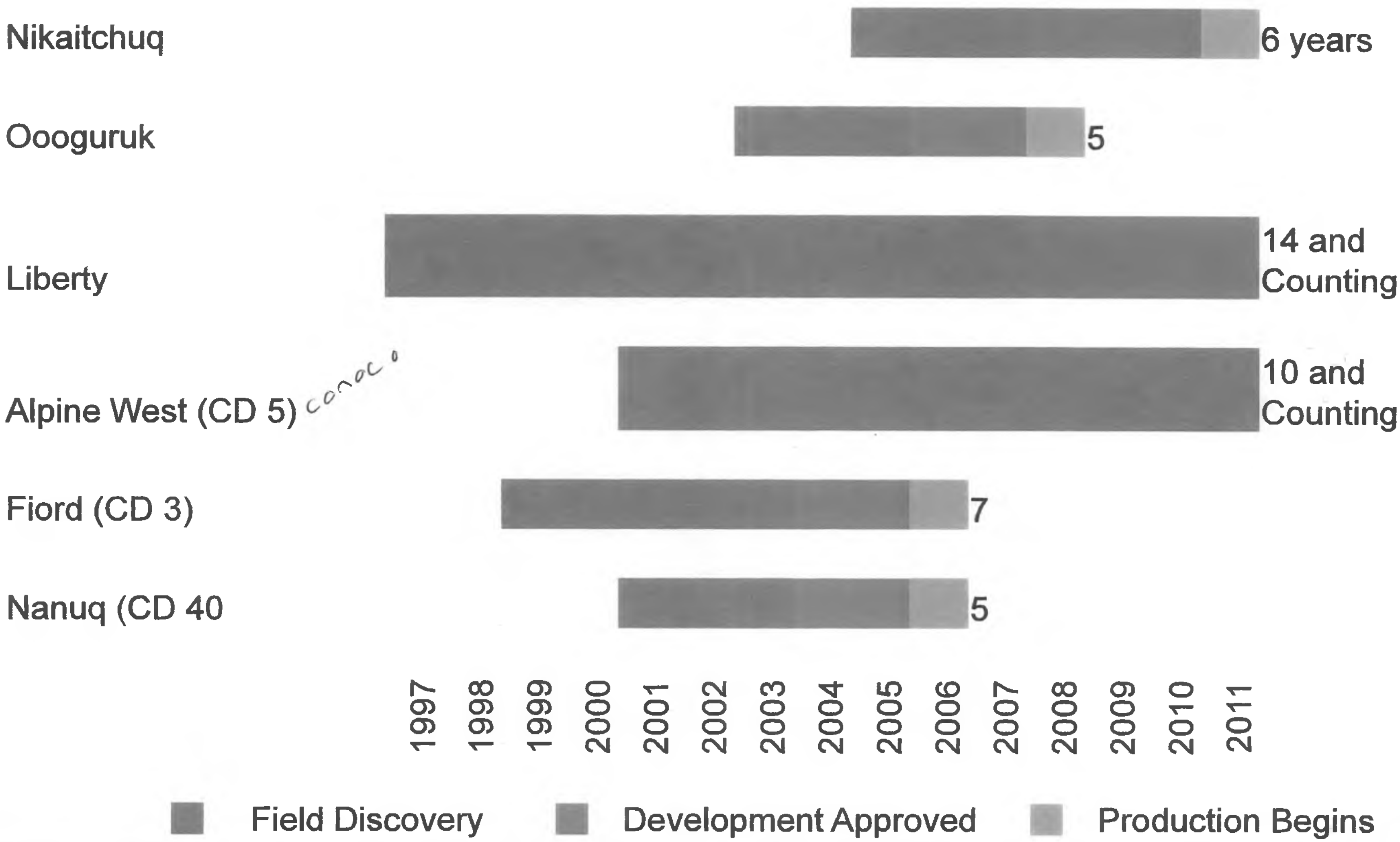


Source: Northern Economics – Baseline Production based on 2007 DOR Forecast

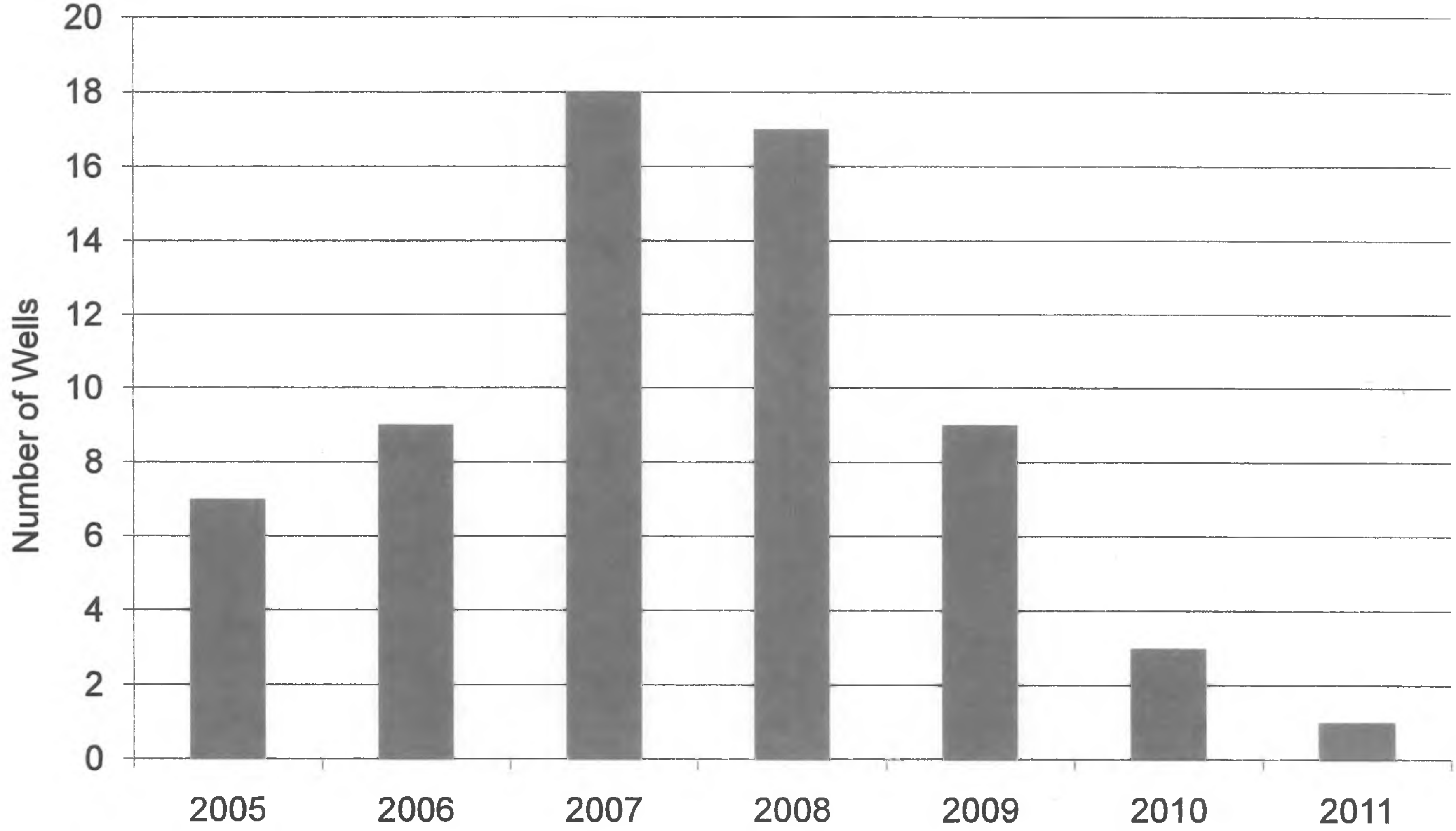
AOGA

Looking Ahead

Development Takes Time



Exploration Wells Drilled On North Slope

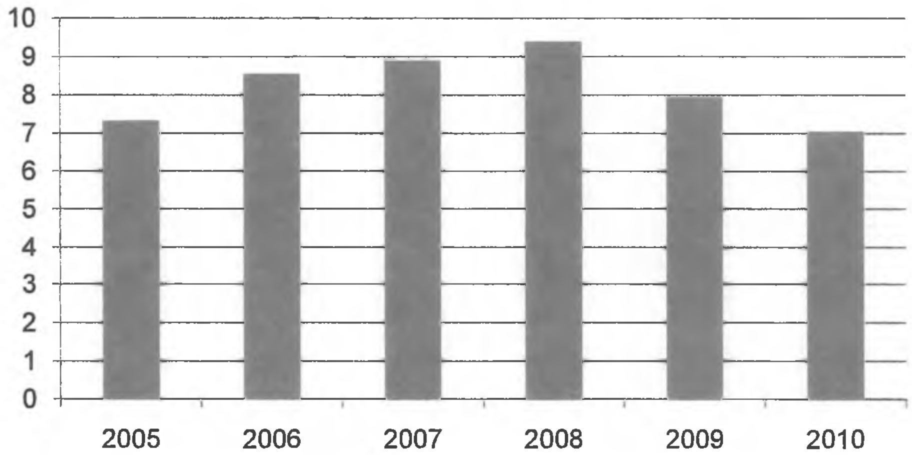


Source: Alaska Oil & Gas Conservation Commission & Department of Natural Resources

Arctic Lease Status

Source: Mapmakers Alaska - "GIS-Arctic Oil & Gas©" database

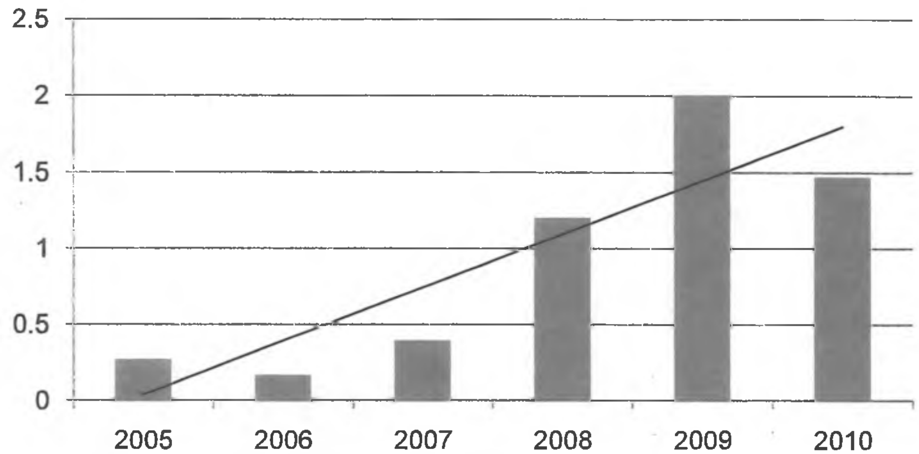
Total Acres Under Lease



Fed, state, offshore across north slope

Implied companies relinquish cause of tax system... but there are other reasons.

Acres Relinquished



HB 110 – New Policy for Alaska

AOGA Supports HB 110 & Governor Parnell's Goals of:

Making Alaska More Competitive

Creating More Jobs

Increasing Production

AOGA's Position on Elements of HB 110

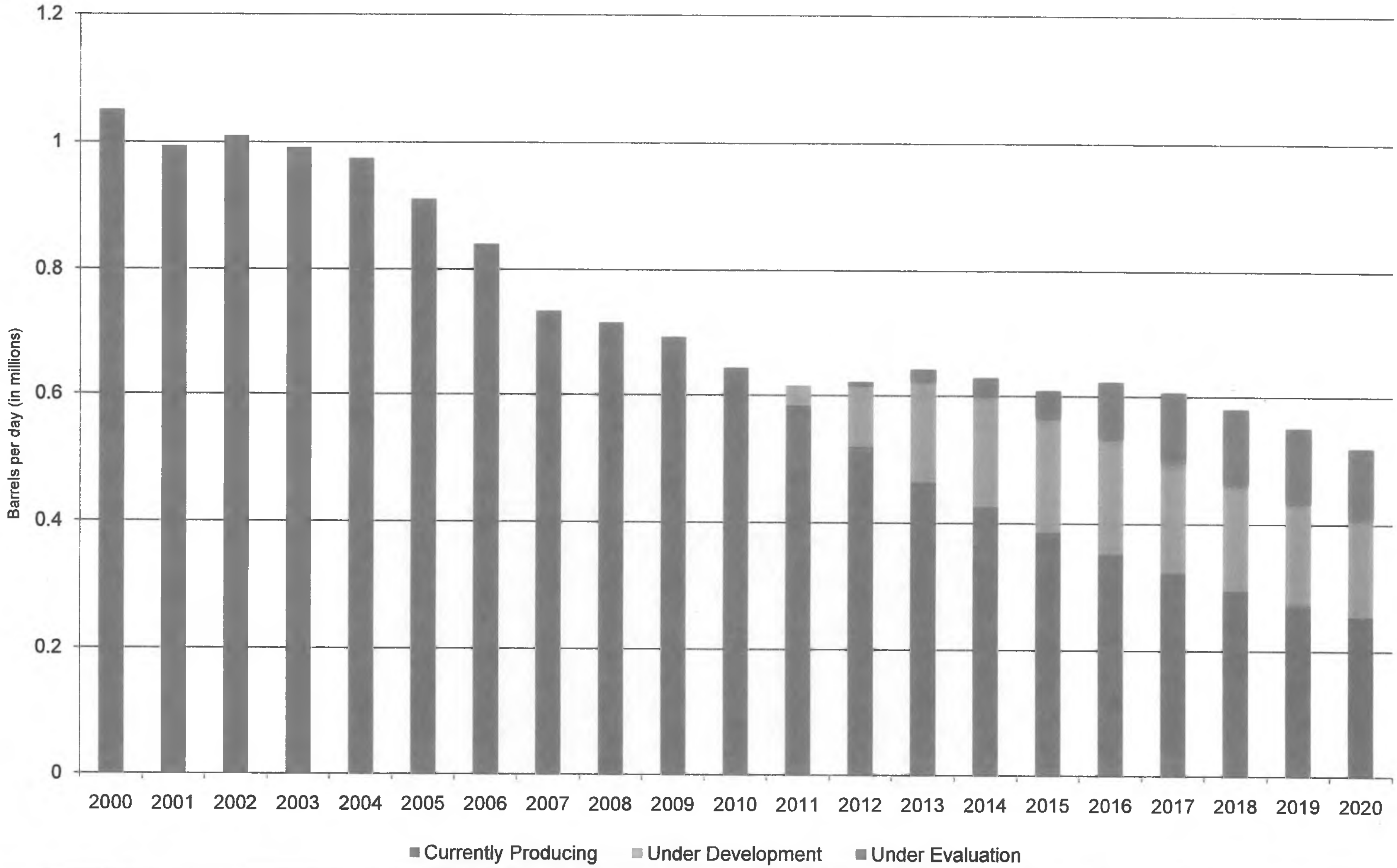
Element of HB 110	AOGA Position
Progressivity Rates/Bracketing/ Tax Cap	over $30 barrel tax ↑ on all $'s. 50% cap v. 75% Support
40% Tax Credit	Support
Yearly Tax Calculation v. monthly	Support
2 Effective Dates 2012 ? progressivity? 2013 stabilization 6 yrs to 4 yrs. 2014 wants immediate effective date = stability.	Concern but not huge.
New Rate for New Fields	Support/Concern
Reducing Interest Rate; Statute of Limitations	Support
Minimum Tax	Concern

AOGA

Looking Ahead


www.aoga.org
AOGA
Looking Ahead

Investment is Crucial to Stem Decline



Alaska Oil and Gas Conservation Commission (AOGCC)

333 W. 7th Ave., Ste. 100
Anchorage, AK 99501
(907)279-1433
www.aogcc.alaska.gov

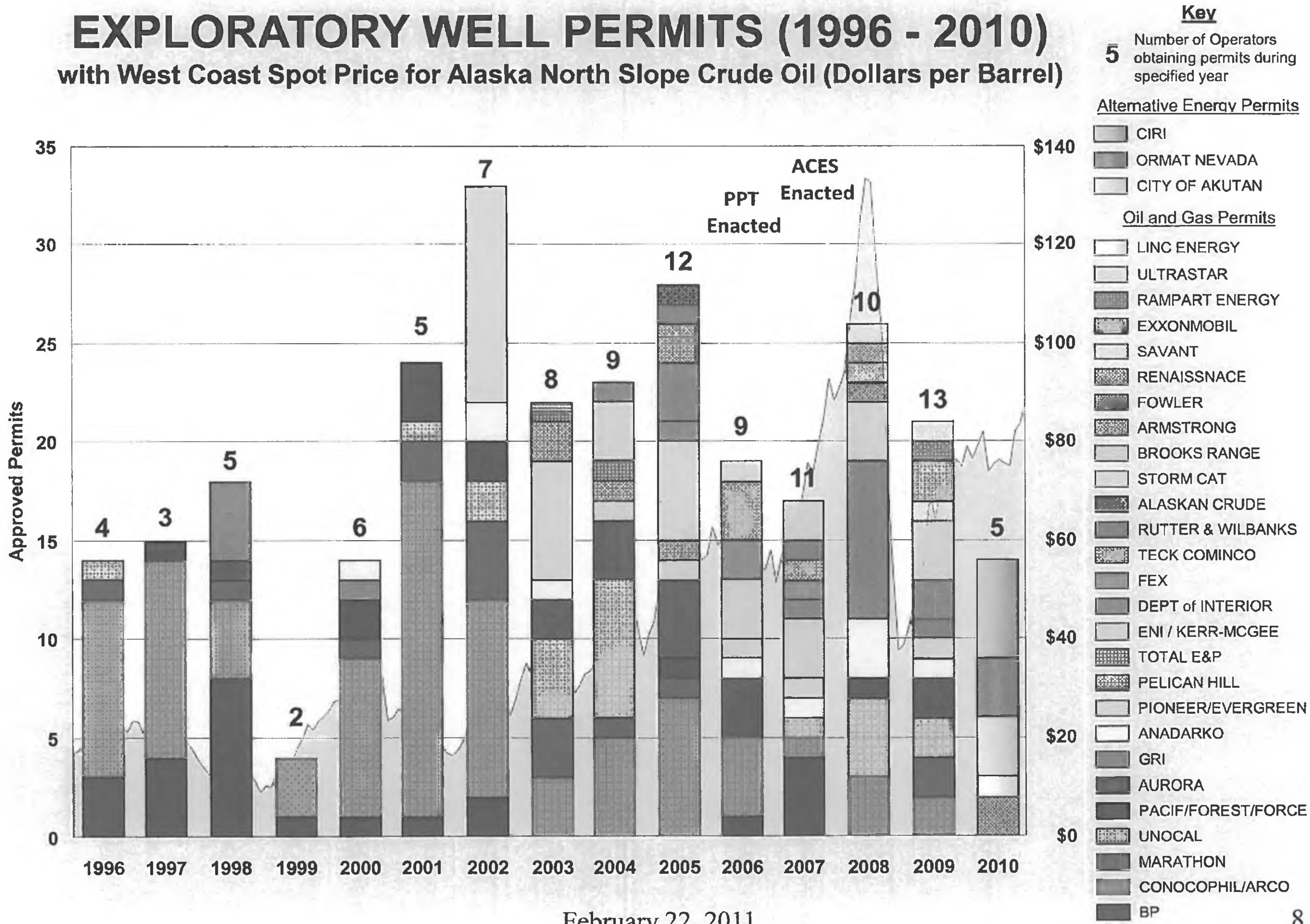
Daniel T. Seamount – Geology Commissioner, Chair
Cathy P. Foerster - Engineering Commissioner
John K. Norman – Public Member Commissioner

February 22, 2011

Activity Trends

EXPLORATORY WELL PERMITS (1996 - 2010)

with West Coast Spot Price for Alaska North Slope Crude Oil (Dollars per Barrel)

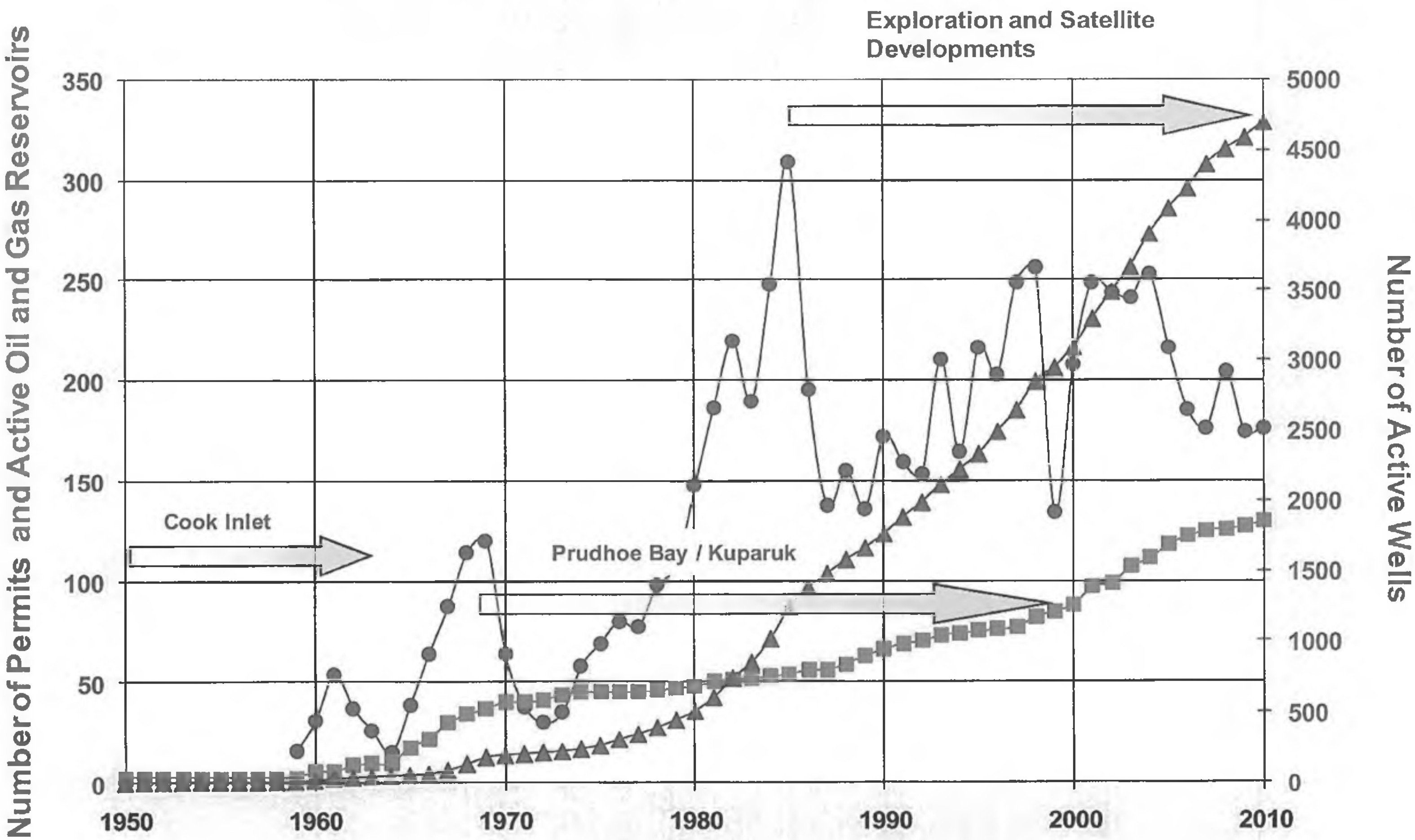


February 22, 2011

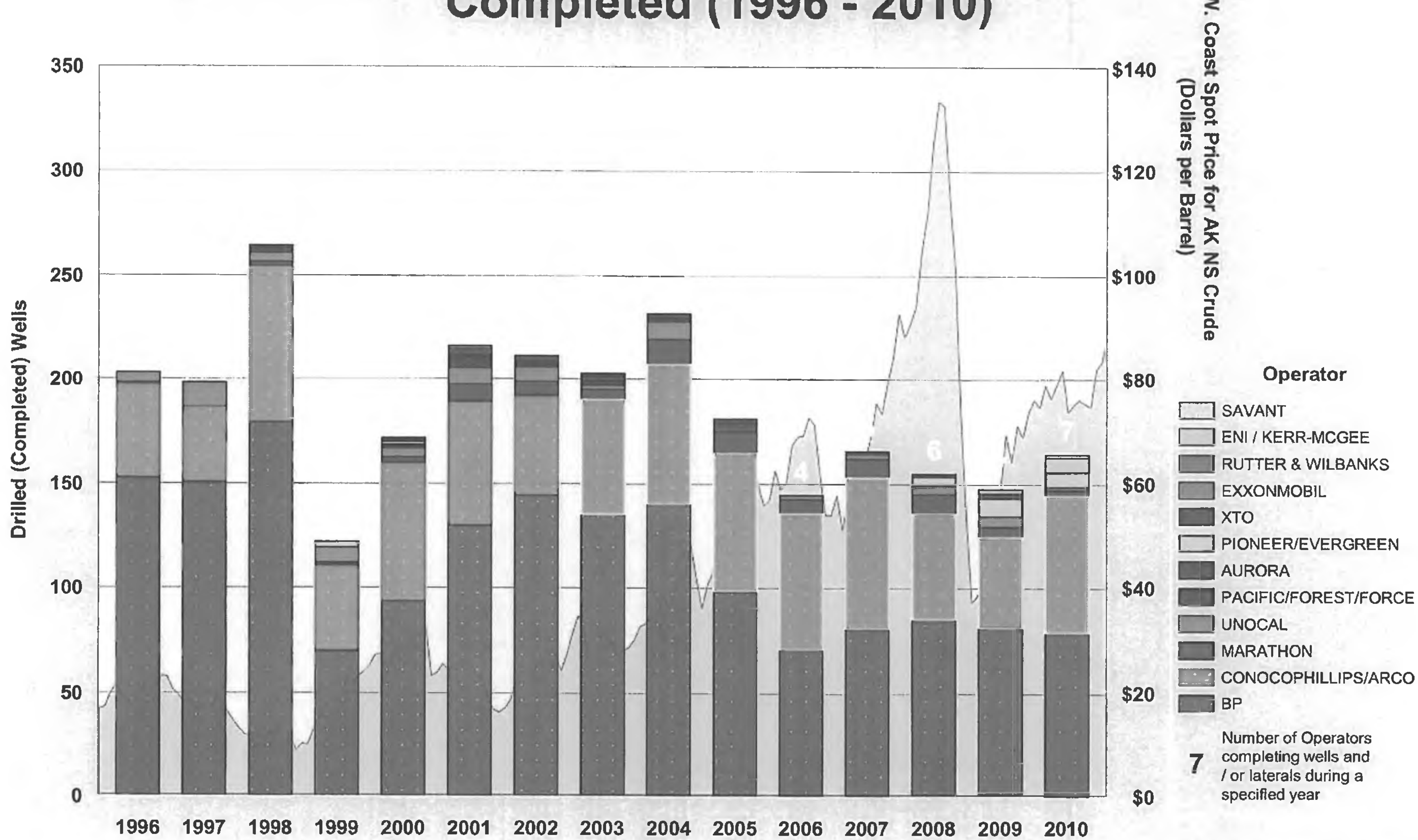
Total Permits = 292

January 4, 2011

Alaska Oil & Gas Activity



DEVELOPMENT AND SERVICE WELLS / LATERALS Completed (1996 - 2010)



Total Wells / Laterals = 2,780

Petroleum news

Vol. 16, No. 6 Week of February 06, 2011

Providing coverage of Alaska and northern Canada's oil and gas industry

US drilling rig count up by 19 to 1,732

The number of rigs actively exploring for oil and natural gas in the U.S. increased by 19 the week ending Jan. 28 to 1,732.

Houston-based Baker Hughes Inc. reported that 913 rigs were exploring for gas and 809 for oil. Ten were listed as miscellaneous. A year ago, the count was 1,317.

Of the major oil- and gas-producing states, Pennsylvania gained 10 rigs, Louisiana gained five, New Mexico gained four, Alaska gained three, Colorado gained two and Wyoming gained one.

Arkansas and Oklahoma each lost two rigs and California, North Dakota and Texas each lost one. West Virginia was unchanged.

The rig count peaked at 4,530 in 1981, the height of the oil boom. The record low of 488 was in 1999.

—The Associated Press

Petroleum news

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Vol. 15, No. 51 Week of December 19, 2010

Providing coverage of Alaska and northern Canada's oil and gas industry

Two more Oooguruk drill sites in the works

Pioneer's proposed Nuna project gives offshore unit onshore drilling pads, presumably to reach Torok formation in Moraine prospect

Kay Cashman

Petroleum News

Three weeks after Pioneer Natural Resources gave investors an expanded Oooguruk map that added six leases and one new onshore drill site to the south and southwest of the Beaufort Sea unit, the company delivered a proposed "Nuna" development project for the same area to the State of Alaska. But the Nuna map and fact sheet, released to the state in early December, called for two new onshore drill sites and a tie-in pad, plus associated gravel roads and pipelines.

Pioneer has made no secret of the fact it is searching for more sources of oil at Oooguruk. In an early May investor conference call, Pioneer President and CEO Tim Dove mentioned the possibility of a new onshore gravel drill site for the unit, noting that earlier in the year the Texas-based independent's Alaska subsidiary had drilled into the northern end of the Moraine prospect, a 3,000-foot well that produced from the Torok formation at initial rates of 1,100 barrels per day.

The new drill site, Dove said, would allow Pioneer to drill into the southern part of the prospect.

Oooguruk's existing drill site is a six-acre artificial gravel island about 5.7 miles from shore.

Torok, the third producing horizon at Oooguruk, is a large stratigraphic trap of thinly laminated sands that sits about 1,000 feet above producing Kuparuk pool, which in turn overlies deeper and larger Nuiqsut.

Every Oooguruk well into the Kuparuk and the Nuiqsut has been drilled through the Moraine, so Pioneer has said it has a lot of data on the prospect.

Early production estimates from the unit, which sits in 4-5 feet of water, was close to 12,000 barrels of oil in November, up 5,000 barrels a day from its third-quarter average. Production is expected to reach 15,000-20,000 barrels per day in 2011.

Production currently comes mainly from Jurassic Nuiqsut sandstone and Kuparuk C sandstone reservoirs.

No permits filed yet

The Nuna details released to the state — permits won't be filed until sometime in early 2011 — do not mention an Oooguruk unit expansion or the Torok formation and the Moraine prospect; rather Pioneer said the two new onshore pads will allow the company to use extended reach drilling to "reach resources not accessible" from Oooguruk's existing offshore drill site.

If the Nuna project is sanctioned by Pioneer, civil construction "could commence in 2013 with first oil in 2014 or later," Pioneer said, noting that sanctioning "would not occur until completion of appraisal work and receipt of major agency approvals."

The company said "preliminary engineering" had identified a development scenario that included:

• Two drill sites on the eastern bank of the Colville River;

• A tie-in pad adjacent to KRU drill site 3S (DS-3S);

• Using existing infrastructure at the Oooguruk tie-in pad, including power generation, gas compression and camp facilities to reduce the need for additional infrastructure;

• Utility service, including water, gas and power, that would come from elevated flowlines from the Oooguruk tie-in pad to the new drill sites via DS-3S;

• Gravel roads to connect the two new drill sites to DS-3S;

• Waste streams injected into approved disposal wells at the drill sites; and

• Three-phase production that would be transported for processing to the ConocoPhillips-operated Kuparuk River unit via a flowline tie-in at DS-3S.

Standalone processing facility a possibility

Whether the Nuna development is ultimately part of a formal Oooguruk unit expansion or not, it still bodes well for increased production from the area for

Pioneer and its 30 percent partner in all the leases, Eni Petroleum. The more oil operator Pioneer can produce, the better chance it has of justifying the construction of its own processing facility.

Currently, Oooguruk oil and small amounts of gas are being processed at Kuparuk, where PN sources say Pioneer has to pay stiff back-out fees because Kuparuk has to forego processing some of its own oil, and — some say — because Kuparuk is the only game in town. Neither observation has been confirmed by Pioneer, which has only praise for its facility sharing agreement with ConocoPhillips.

Here is what Pioneer spokesman Tadd Owens recently told PN about the possibility of Pioneer building its own facility for Oooguruk: "At this time we are not planning to construct our own production processing facility. However, that option remains available to us if at some point in the project's future we determine the economics justify constructing our own processing plant."

When asked if Pioneer was planning to use its partner Eni's soon-to-be-online facilities at the adjacent Nikaitchuq unit, he said: "At this time we have no plans to use facilities at Nikaitchuq to process production from Oooguruk. Going forward we will continue to evaluate any opportunities to enhance the economics of our project."

It would require an eight-mile line to deliver Oooguruk oil to Nikaitchuq's processing facility.

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Petroleum news

Vol. 15, No. 51 Week of December 19, 2010

Providing coverage of Alaska and northern Canada's oil and gas industry

Delegation urges CD-5 application action

Alaska's members of Congress have written to administration officials, expressing concern over delays in first NPR-A development

Kristen Nelson

Petroleum News

The members of Alaska's congressional delegation — Sens. Lisa Murkowski and Mark Begich and Congressman Don Young — have written to top administration officials to express concern about lack of coordination among federal agencies on ConocoPhillips Alaska's CD-5 permit application.

In February the Corps of Engineers rejected ConocoPhillips' plan to develop its lease holdings on the eastern edge of the National Petroleum Reserve-Alaska by constructing a gravel road and bridge across the Nigliq Channel of the Colville River. The corps said a pipeline buried under the Nigliq Channel would have less of an environmental impact.

ConocoPhillips appealed and in early December the corps remanded some issues for reconsideration.

In a letter to Secretary of the Interior Ken Salazar, Environmental Protection Agency Administrator Lisa Jackson and Assistant Secretary of the U.S. Army for Civil Works Jo-Ellen Darcy (Corps of Engineers), the Alaska delegation said they have "ongoing concerns and interest" in the appeal by ConocoPhillips Alaska of the denial by the corps' Alaska District of a permit for the CD-5 Alpine satellite development in NPR-A.

More wells planned at CD-1, CD-2, CD-3

ConocoPhillips Alaska is requesting approval to install additional wells at Alpine beginning this winter "because of the delays associated with the CD-5 development."

Two wells are proposed for the CD-1 pad, five wells for the CD-2 pad and eight wells for the CD-3 pad (Fiord).

The company said the number

Commenting on the decision by the corps' Alaska District, the three said the Alaska District "had insisted, despite nearly five years of environmental study and careful consultation with tribal, local, state, and federal stakeholders, that a three-phase buried pipeline — requiring exponentially increased air traffic and subject to uncertain monitoring issues over the life of the fields — would be less environmentally damaging than the proposed road."

Several of ConocoPhillips' reasons for appeal were validated, and remanded to the Alaska District.

"This may indicate the complexity of the issue, but we worry that it also speaks to a chronic and unacceptable void in communication and transparent analysis on the part of those agencies responsible for advancing this important project," the delegation said.

Not advocating specific course

The Alaska delegation said it was not advocating a specific course of action.

"We are, however, compelled to voice our serious and continued disappointment at the federal government's persistent inability to coordinate its agencies in such a way as to move this critical project forward on a reasonable timeline."

They argued that prospects in a National Petroleum Reserve should be the most "assertively pursued and permitted" of any national oil and gas prospects.

"The opposite has occurred in this case, and this is already proving needlessly costly in terms of jobs, federal leasing revenues, and the Administration's stated goal of energy independence."

Aquatic resource

On the subject of EPA's "designation of the Colville River Delta as an 'aquatic resource of national importance' for purposes of this application," the delegation said that "caused as both alarm and curiosity as regards the process and power behind this designation."

"Insofar as those who actually depend on the Colville for its aquatic resources, this designation flies in the face of their preferred method of accessing CD-5," the delegation said, and noted that this was not surprising, "since the designation requires no public input, consultation, or even notice."

They questioned whether steps to permit this and other projects in a petroleum reserve "give the applicant and the public a clear path forward and transparent public record," and said they hoped "to better understand what appears to be an opaque, unilateral process to many seasoned observers."

Whatever the outcome of ConocoPhillips' appeal, the delegation said they "expect both thoughtful and swift responses to the issues raised in this letter, and we expect those responses to occur in the form of both words and concurrent action."

of wells at CD-2 and CD-3 exceed the proposed number of wells in the original development plans for those pads. A total of wells was never proposed for CD-1.

All wells are planned for existing gravel.

—Kristen Nelson

Alaska Department of
NATURAL RESOURCES
DIVISION OF OIL & GAS

North Slope

Drilling Activity

January, 2011

Compiled by Division of Oil and Gas

Exploration Drilling

What drives exploration?

- Economy
- Land availability
- Evolving exploration concepts
- Advances in seismic and drilling technology

What affects exploration in Alaska?

- Successful exploration (encourages more exploration)
- Available acreage
- Global economics of oil & gas
- Fiscal regime

Recent explorers on the North Slope:

- Chevron
- ConocoPhillips
- Anadarko
- FEX
- ENI
- Pioneer
- Brooks Range
- Savant
- Rampart
- UltraStar

Seismic Technology

The revolution of 3D Seismic in the 1990s changed the map by allowing exploration companies to search for more subtle stratigraphic traps than earlier technology allowed. Usually, development of an area expands from the obvious structural traps, leading to better understanding, and to further exploration. Now, exploration on the North Slope has developed past the obvious structural traps.

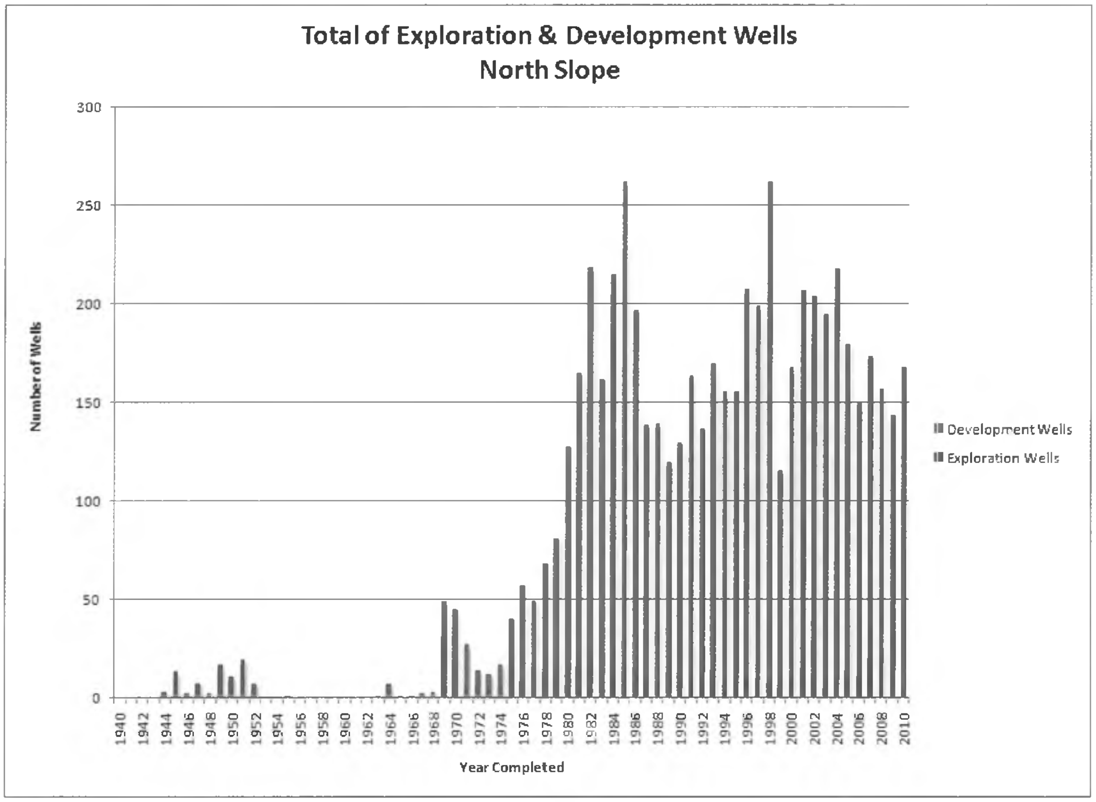
2000 to 2010:

- Primary exploration activity north of the Kuparuk field (Oooguruk and Nikaitchuq fields)
- Also activity in the vicinity of Alpine and its satellites, Fiord, Nanuq, Qannik, and NPR-A.
- ConocoPhillips, in partnerships with Anadarko and Pioneer, has operated more exploration wells in NPR-A than any other company since the renewal of BLM leasing there in 1999. The company drilled 19 NPR-A wells and multiple sidetracks between 2000 and 2009, with most of the drilling and the greatest success concentrated in northeast NPR-A. ConocoPhillips has announced discoveries of multiple hydrocarbon accumulations in Upper Jurassic Alpine-equivalent reservoir sandstones, and has gone on to form and expand the BLM-administered Greater Moose's Tooth unit encompassing those discoveries. In addition, ConocoPhillips also formed the adjacent BLM-administered Bear Tooth Exploration Unit, based on Cretaceous and Jurassic sandstone prospects. ConocoPhillips has also operated exploration wells farther west in NPR-A, including Puviaq 1 near the Ikpikpuk River and Intrepid 2 south of Barrow's Walakpa gas field.
- Other operators operating exploration wells in NPR-A since 2000 include BP (two Trailblazer wells), Total (Caribou 1), Anadarko (Altamura 1 and Wolf Creek 4 wells), and FEX (four Aklaq, Aklaqyaaq, and Amaguq wells). Several of these wells remain confidential pending lease expiration per BLM policy, but clearly the region has been explored for multiple play concepts in the last decade. The Trailblazer leases expired during 2010 and those two wells should be released to the public by February, 2011. FEX is currently in the process of

marketing their NPRA acreage, and have no further plans in NPR-A.

- Foothills oil and gas accumulations originally discovered decades ago were retested by several new wells in 2008 and 2009 in Anadarko's drilling campaign with partners Petro-Canada and BG. The partnership drilled two wells evaluating the Gubik gas accumulation (Gubik 3 and 4), and one flanking the previously discovered East Umiat gas accumulation and assessing the potential of deeper Brookian strata there (Chandler 1). Anadarko's Wolf Creek 4 was also drilled in 2009, following the same frontal structural zone of the foothills belt in southeast NPR-A. Anadarko did not drill any wells in 2010 and has no plans for 2011 drilling in the Gubik area, waiting on economic issues such as the availability of a gas pipeline before considering further delineation and development. Renaissance still has permitted drilling locations on its Umiat acreage, but future activity will depend on finding investors and the possibility of development of road access to their Umiat site (west of the Colville River).
- In addition to drilling activity, the last decade has seen significant new seismic acquisition in the foothills belt, including proprietary 3D programs in the vicinity of the Kavik gas accumulation near ANWR, and over the Umiat oil accumulation and Gubik gas accumulation near the Colville River, as well as more regional, high quality 2D surveys on state, federal, and native lands across much of the central foothills belt. DNR has maintained its program of integrated foothills field investigations and subsurface studies throughout the last decade, and is currently focused on the Umiat – Gubik area. These projects focus on clarifying the region's oil and gas potential and delivering results to a broad audience, including industry and decision makers in state and federal agencies.

Development drilling



Development drilling reflects a company's efforts to develop a discovery, satellite, or similar prospect near existing infrastructure.

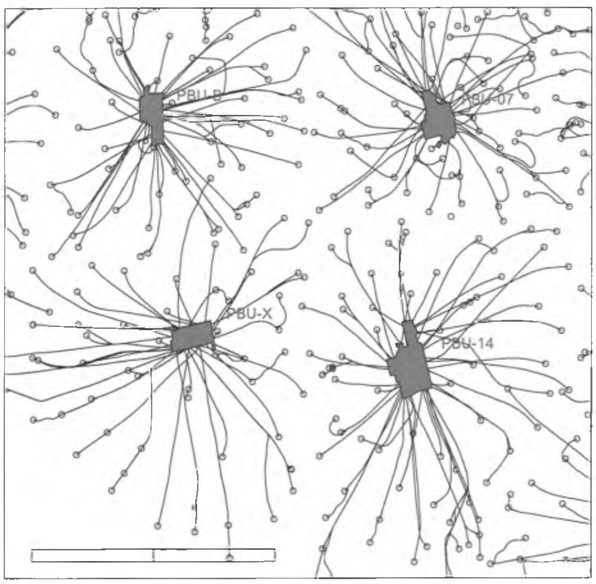
North Slope development is staying fairly strong, but the graph above shows that it is somewhat cyclic in response to industry-wide conditions: oil prices, costs, and alternative development opportunities.

Drilling activity is also affected by the timing of development programs. One year of development drilling will be followed by a year of tie-back and facility installation.

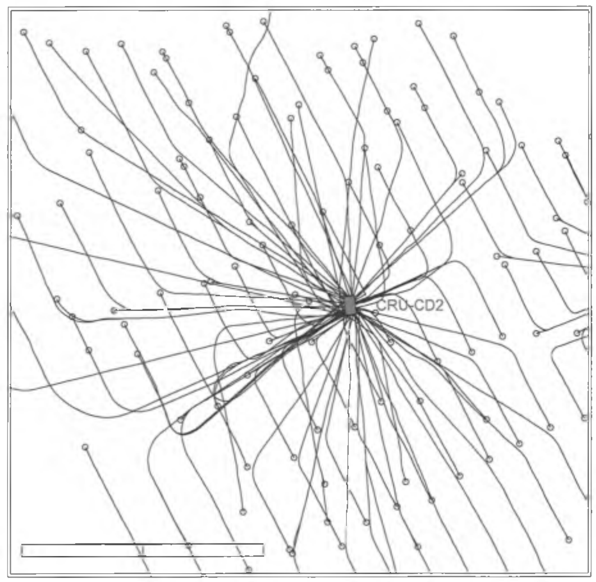
Drilling technology

Advances in drilling technology have greatly advanced the reach of modern exploration and development wells.

- The Alpine field discovered in 1994 and delineated in the late 1990's was the first North Slope field to be developed exclusively with all horizontal wells, both producers and injectors.
- The use of multi-lateral technology has improved the economics and oil recovery of the West Sak and Schrader Bluff formations (Shallow Sands)
- Horizontal and multi-lateral drilling technology represents a cost-effective method to develop remaining oil or oil located in isolated but closely stacked sandstones separated by shale.
- The use of multi-lateral wells helps to keep the numbers up. Each lateral counts as a separate well so comparing activity to a time when laterals were not common may not give an entirely accurate picture. On the other hand, extended-reach horizontal drilling also means that today, the same level of production can be achieved with a fewer number of wells.
- This means not only that more complicated stratigraphic plays can be developed, but also that any formations can be more efficiently drilled and produced with a smaller number of wells.



Prudhoe Bay



Alpine

Division of Oil and Gas, 4/2/2010

Well Count and Well Footage Drilled

Year	ALPINE WELLS	footage	KUPARUK WELLS	footage	PRUDHOE WELLS	footage	OTHER WELLS	footage	TOTAL WELLS	TOTAL Footage
1995	4	28,530	28	296,416	91	715,529	32	353,003	155	1,393,478
1996	8	59,329	42	369,416	106	745,710	51	567,516	207	1,741,971
1997	0	0	36	291,517	116	783,954	44	481,358	196	1,556,829
1998	3	28,869	70	518,764	126	783,871	62	518,764	261	1,850,268
1999	14	154,899	28	245,626	62	265,688	11	102,249	115	768,462
2000	25	313,509	45	330,972	79	363,035	18	168,845	167	1,176,361
2001	16	193,504	51	419,323	93	504,328	46	341,622	206	1,458,777
2002	21	261,815	29	224,979	112	654,919	41	327,397	203	1,469,110
2003	18	267,496	35	309,947	87	460,597	53	440,372	193	1,478,412
2004	20	273,111	47	291,536	100	546,319	50	364,245	217	1,475,211
2005	13	200,332	57	342,433	82	451,733	27	288,400	179	1,282,898
2006	17	242,138	52	404,241	68	360,278	12	100,034	149	1,106,691
2007	14	213,618	59	442,638	70	376,267	30	214,250	173	1,246,773
2008	17	209,252	33	163,326	80	424,910	26	169,595	156	967,083
2009	12	209,030	27	130,565	74	362,924	29	250,202	142	952,721
2010	15	204,422	52	231,111	73	357,506	27	247,752	167	1,040,791
total	**217**	**2,859,854**	**691**	**5,012,810**	**1419**	**8,157,568**	**559**	**4,935,604**	**2886**	**20,965,836**

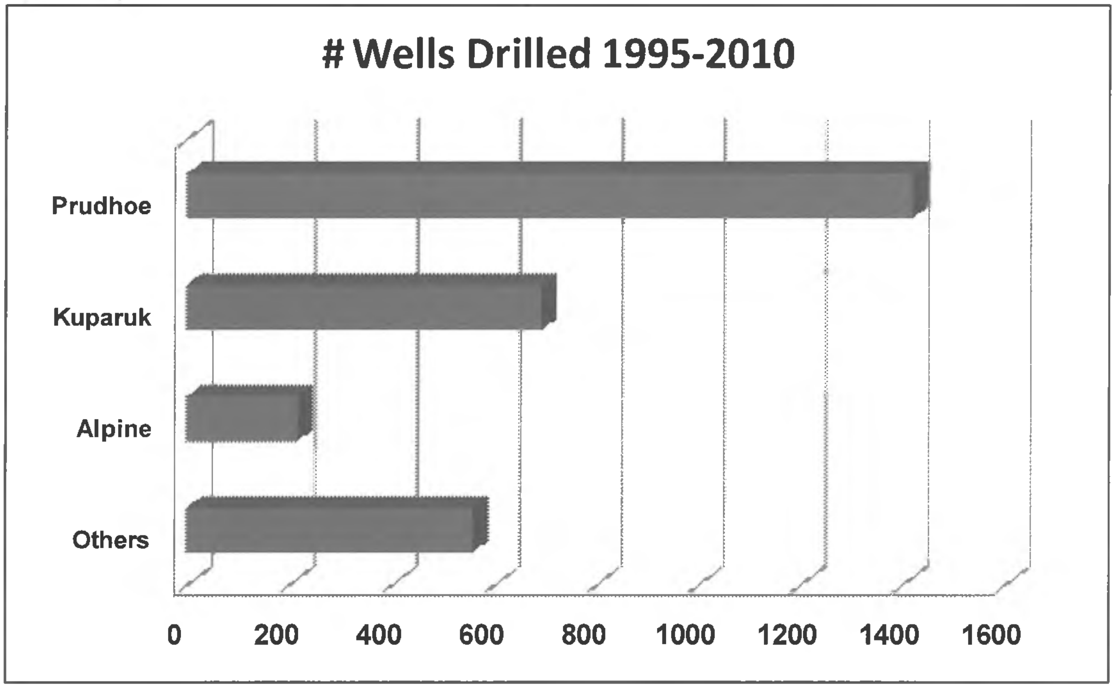
The well count above includes

- Grass roots wells
- Side tracts
- Deepening
- Laterals

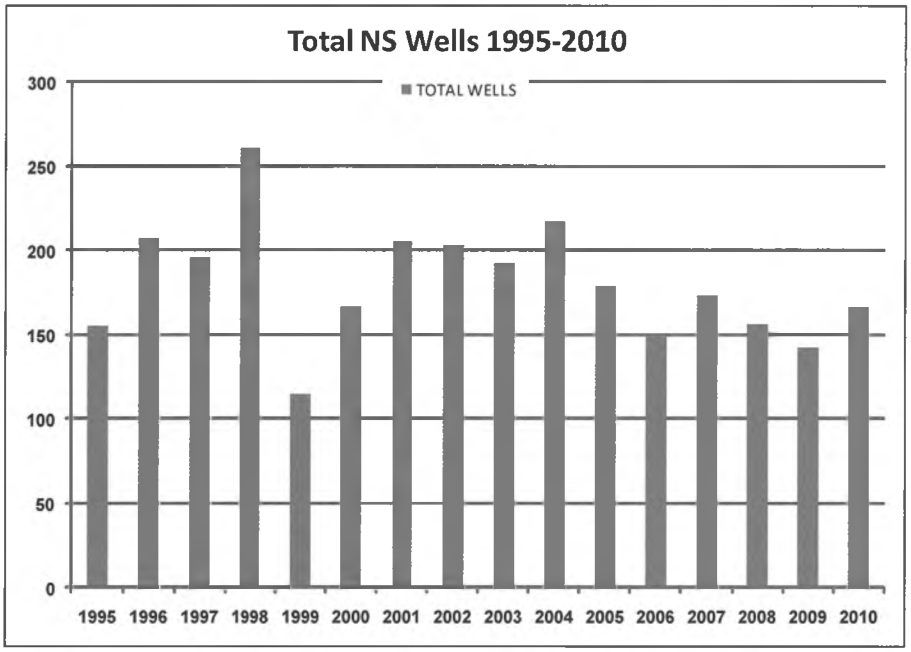
It does not count

- Pilot holes
- Each leg of a multilateral (no systematic repeatable way to count)
- Mechanical sidetracks (where an explorer has a mechanical problem and has to sidetrack to get to their objective. At Oooguruk 3, Pioneer had many (6 or more) sidetracks in one straight hole.
- Where there are multiple bottom holes, targeted sidetracks are counted as separate wells. In an exploration well, the first target might be a straight hole, and the well might then be sidetracked to a new bottom hole a mile away.

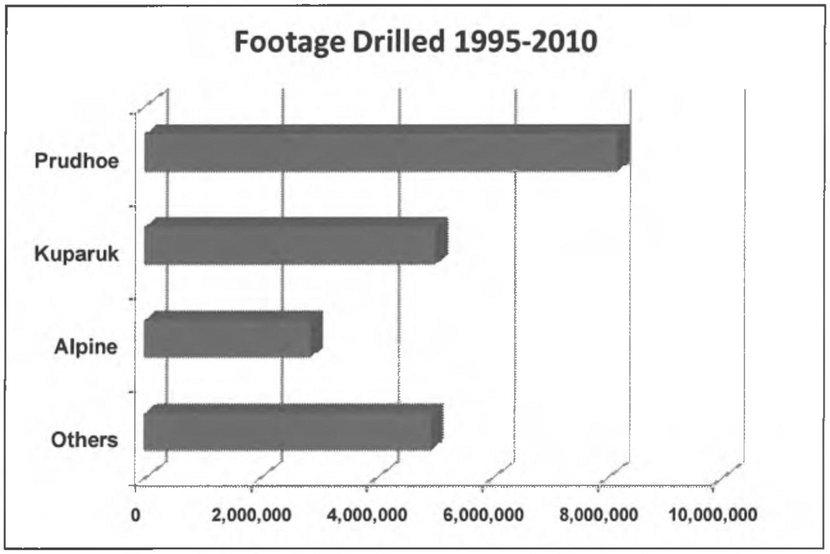
AREA	# Wells	Footage
Others	559	4,935,604
Alpine	217	2,859,854
Kuparuk	691	5,012,810
Prudhoe	1419	8,157,568
Total	**2886**	**20,965,836**

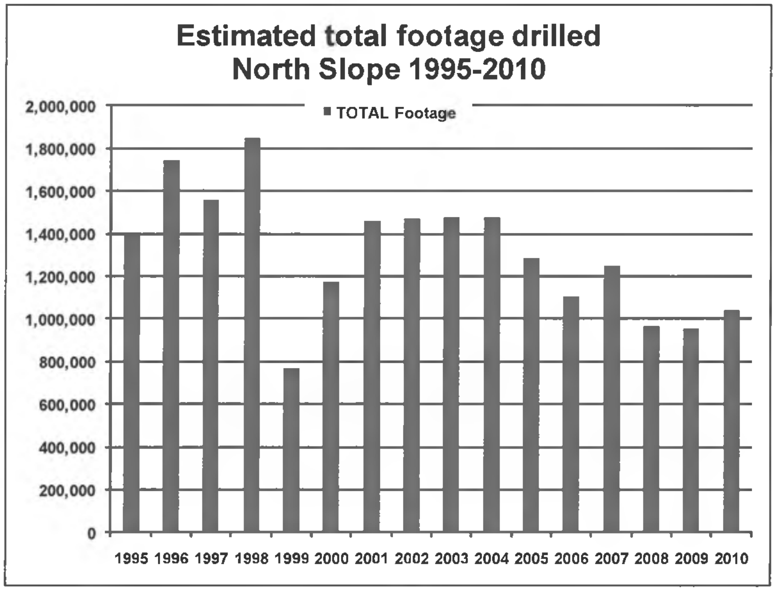


Wells Drilled 1995-2010
Prudhoe
Kuparuk
Alpine
Others
0
200
400
600
800
1000
1200
1400
1600



Total NS Wells 1995-2010
TOTAL WELLS
300
250
200
150
100
50
0
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010





The number of wells, as well as the footage, drilled in any particular year is affected by a number of factors.

Stage of development:

In the early years of developing a new field, infrastructure needs to be put in place (drill pads, well housing, flowlines, etc.) and the initial wells drilled are from the surface. This means that in the early years of development, well footage drilled will be higher, as the developer hits the targeted horizon.

As development progresses, these "grassroot wells" are opened to sidetracking to either maximize production from the well, or to target non-connected pools. The sidetracked wells, going out laterally from a starting point in an initial grassroot well already drilled down, usually are shorter in length. Sidetracked wells are also less costly, given that they benefit from already existing infrastructure.

Drilling development:

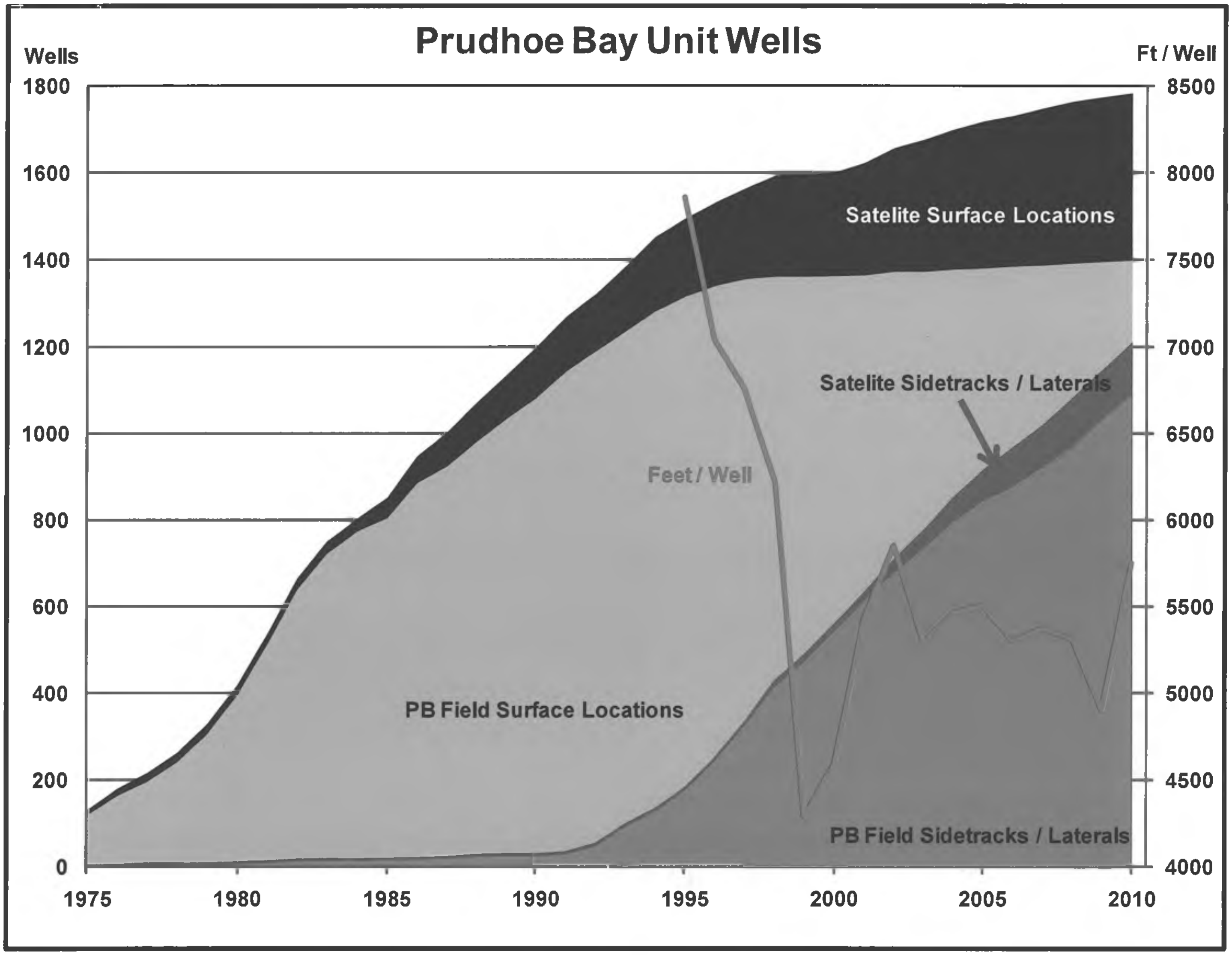
Not only can today's wells drain a larger area from a smaller "footprint" – today's wells are also more efficient than wells drilled in the infancy of Prudhoe Bay.

Equipment availability:

When a drill rig is available, you will see several wells drilled in a field in the same year. A period of drilling is then followed by well-completion and other preparation for production, which means it is normal for a period of drilling to be followed by a period of no drilling – it's all part of the development cycle.

We can see this in looking at graphic representations of the number of wells drilled over the lifespan of a field, as well as the average footage of wells drilled over the same time period.

The following graphs also show the difference in types of wells, number of wells, and footage drilled, comparing older fields (Prudhoe Bay and Kuparuk) with a newer developing field (Colville River).



This graph shows a cumulative plot.

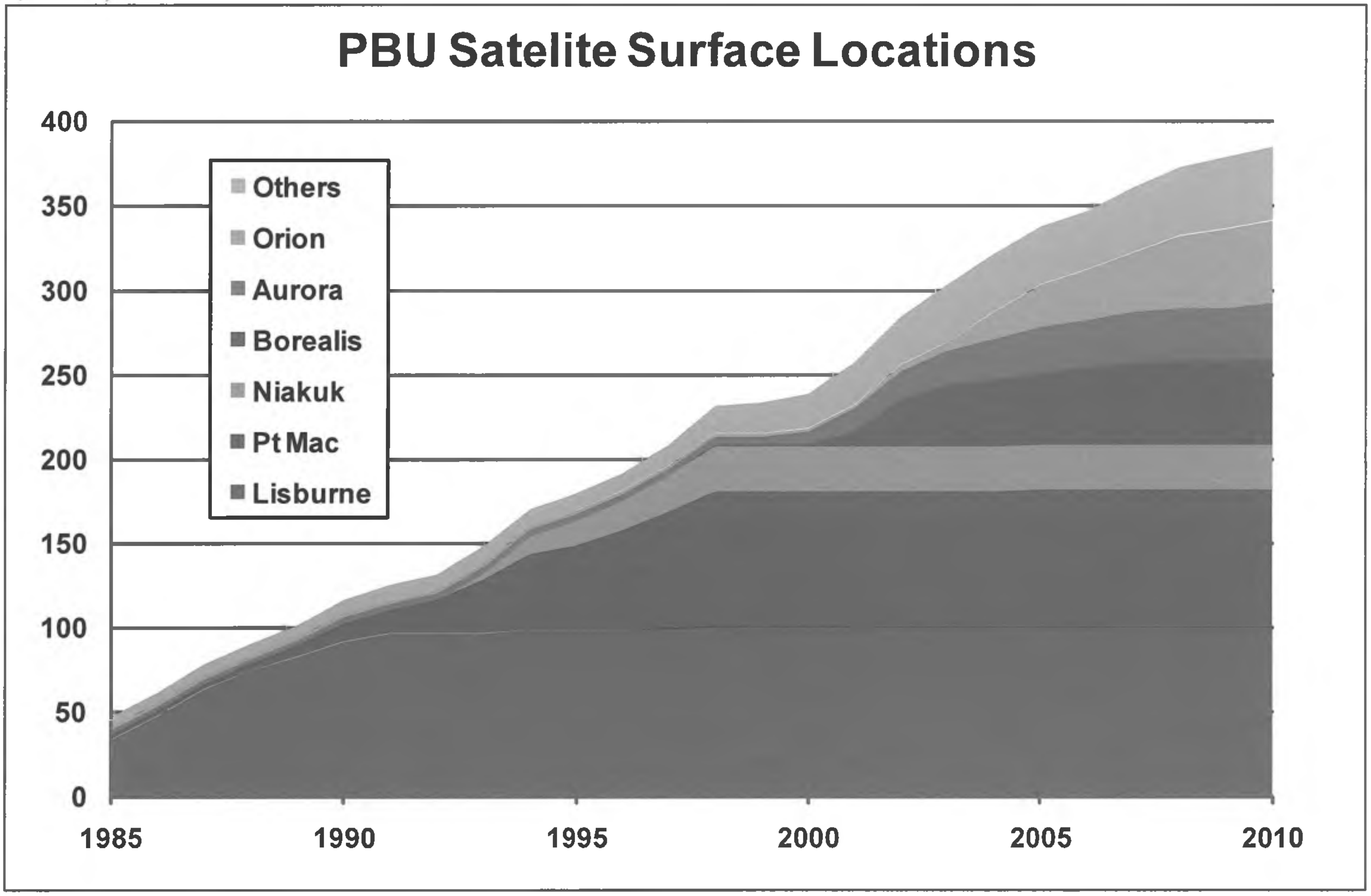
The light blue shows the Prudhoe Bay Unit grassroots wells; a total of about 1,400, drilled in the past 15 years. There is a significant stock of wells in the IPA. New wells require surface facilities (flowlines, well housing, new gravel pads, etc.)

The black shows the satellite grassroots wells. These continue to grow -- there are approximately 400 drilled to date.

Green is Prudhoe Bay IPA sidetracks -- about 1,000 to date, and growing. The last several years' Plans Of Development (POD) talk about waiting for suitable wellbores to sidetrack to target a particular accumulation. 10/14ths of the IPA wells have been sidetracked. Sidetracks require no surface facilities.

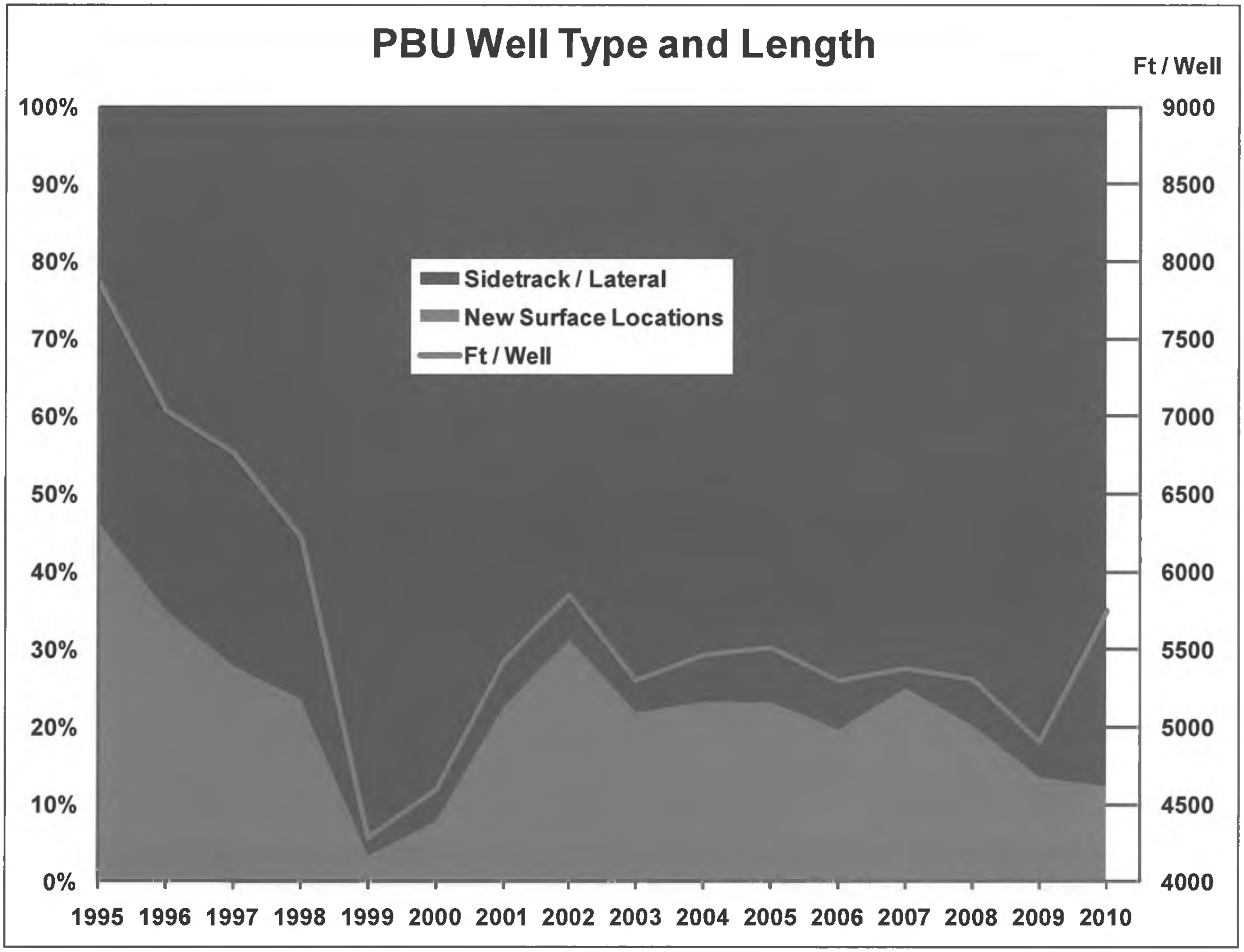
Purple shows satellite sidetracks -- 100 to date, and growing.

The red line shows the number of feet per well drilled (scale on the right side of the graph). As sidetracks increase, there is a significant drop in feet per well.



This graph expands the black wedge from the previous slide, showing only new wells. Notable here is that development of satellites start and finish. Looking, for example, at Pt. MacIntyre or Lisburne, there has been no new wells drilled in many years. This has nothing to do with the financial regime or even oil prices, but is attributable to the fact that the wells have been drilled and the project completed.

Growth here comes from new projects being added -- such as Borealis, Aurora, and Orion.

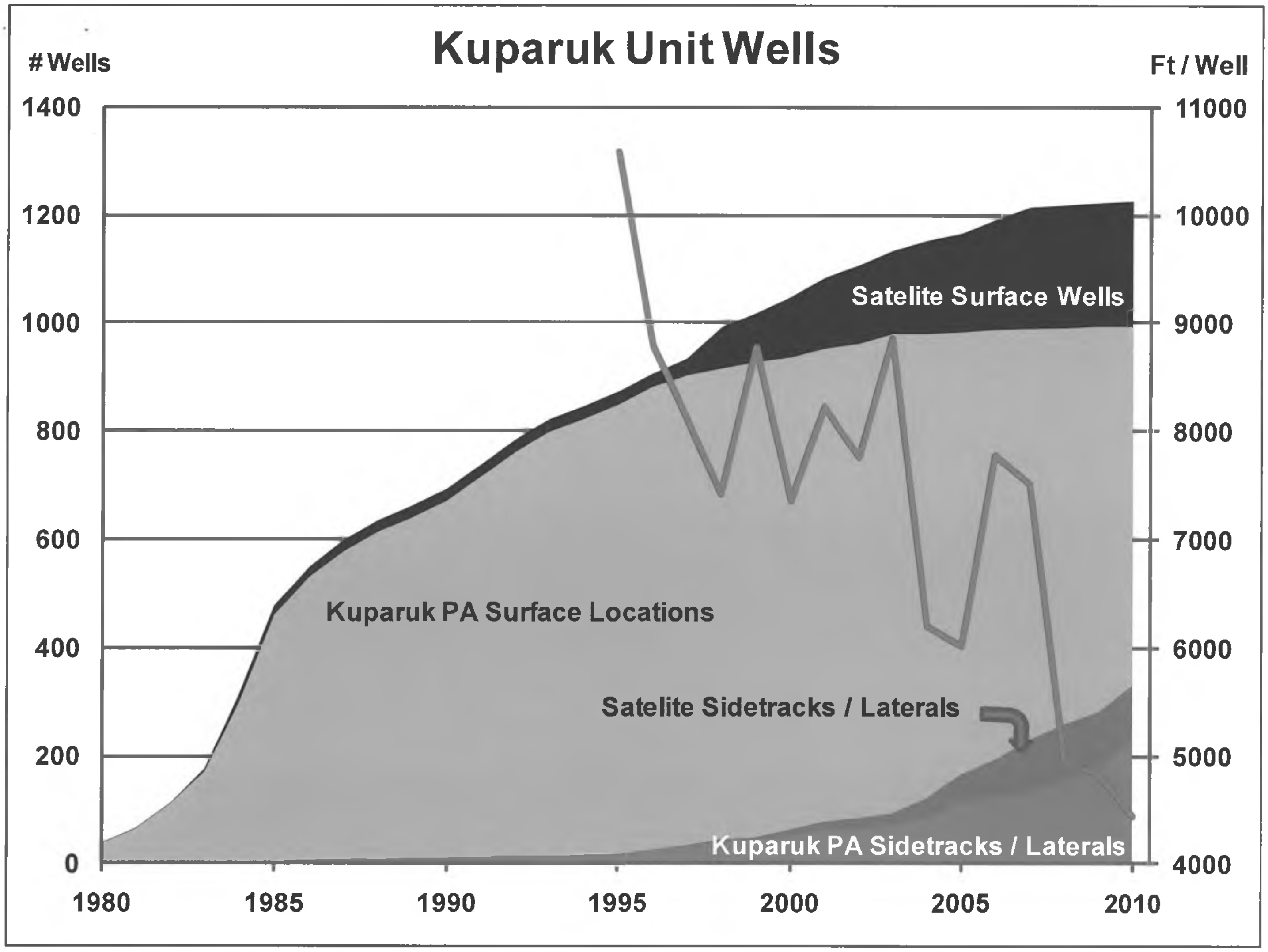


The above graph shows grassroots wells (light blue) as percentage of total wells (dark blue is side-tracks).

In the mid-1990s, about half of the wells in the Prudhoe Bay Unit were grassroots wells, with an average length of 8,000 feet.

Today, only 15 percent of the wells in the Prudhoe Bay Unit are grassroots wells. The average length of a well is 5,000 feet.

This does not point to diminished drilling, but *different drilling*. Sidetracking existing downholes means lower cost (no new facilities, no new gravel pads). Together with greater efficiency in drilling technology this all means lower associated cost for the developer).



This cumulative plot can be compared to the cumulative plot for Prudhoe Bay on page 8.

The light blue shows Kuparuk Participating Unit grassroots wells -- approximately 1,000 drilled, only about 100 of them drilled in the past 15 years.

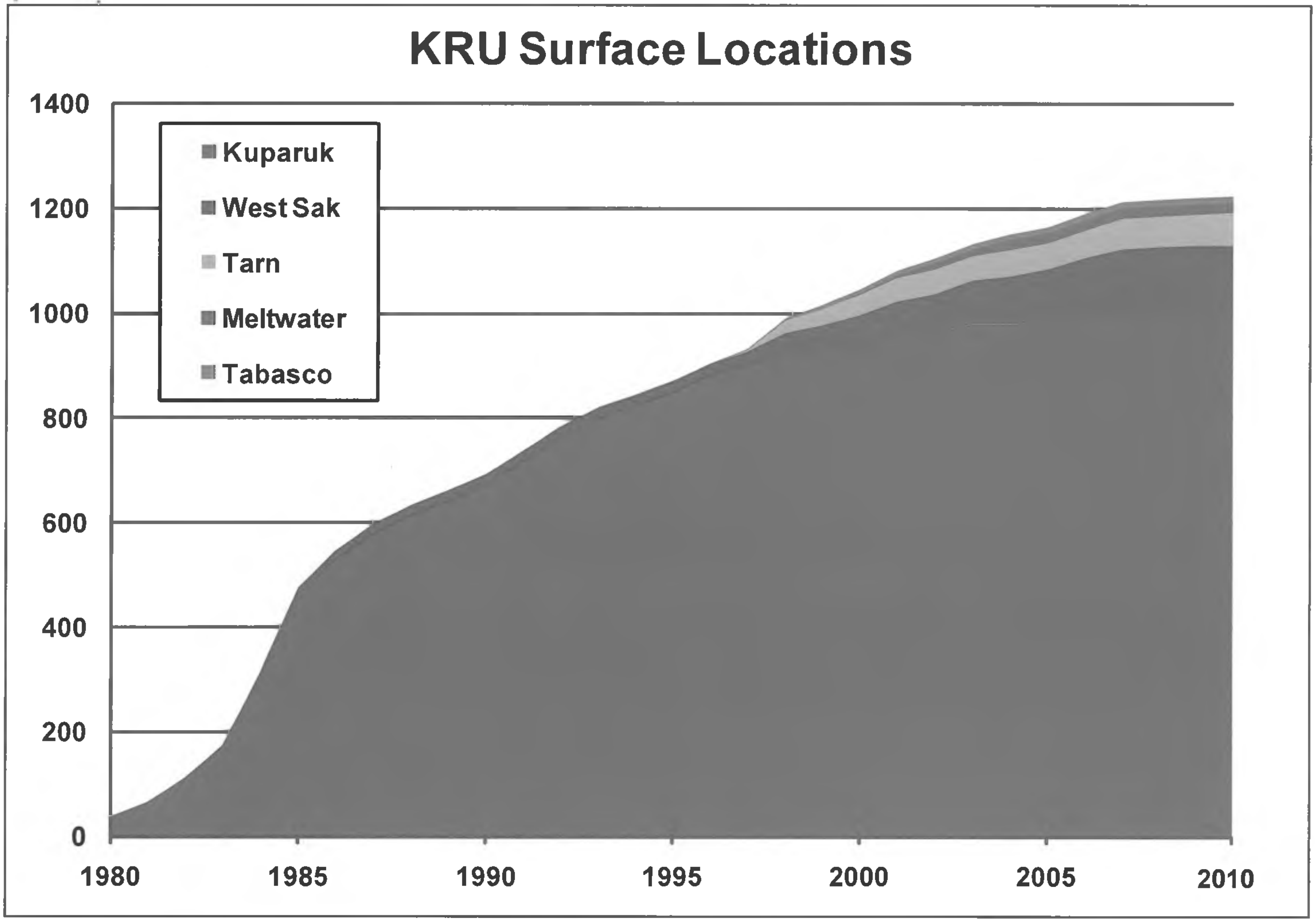
As in the case of Prudhoe Bay, the Kuparuk River Unit has a significant stock of wells.

Black shows satellite grassroots wells -- a category that continues to grow, with about 200 wells to date.

Green shows Kuparuk PA sidetracks and laterals, also approximately 200 drilled to date, and growing. About 20 percent of the Kuparuk Participating Area wells have been sidetracked.

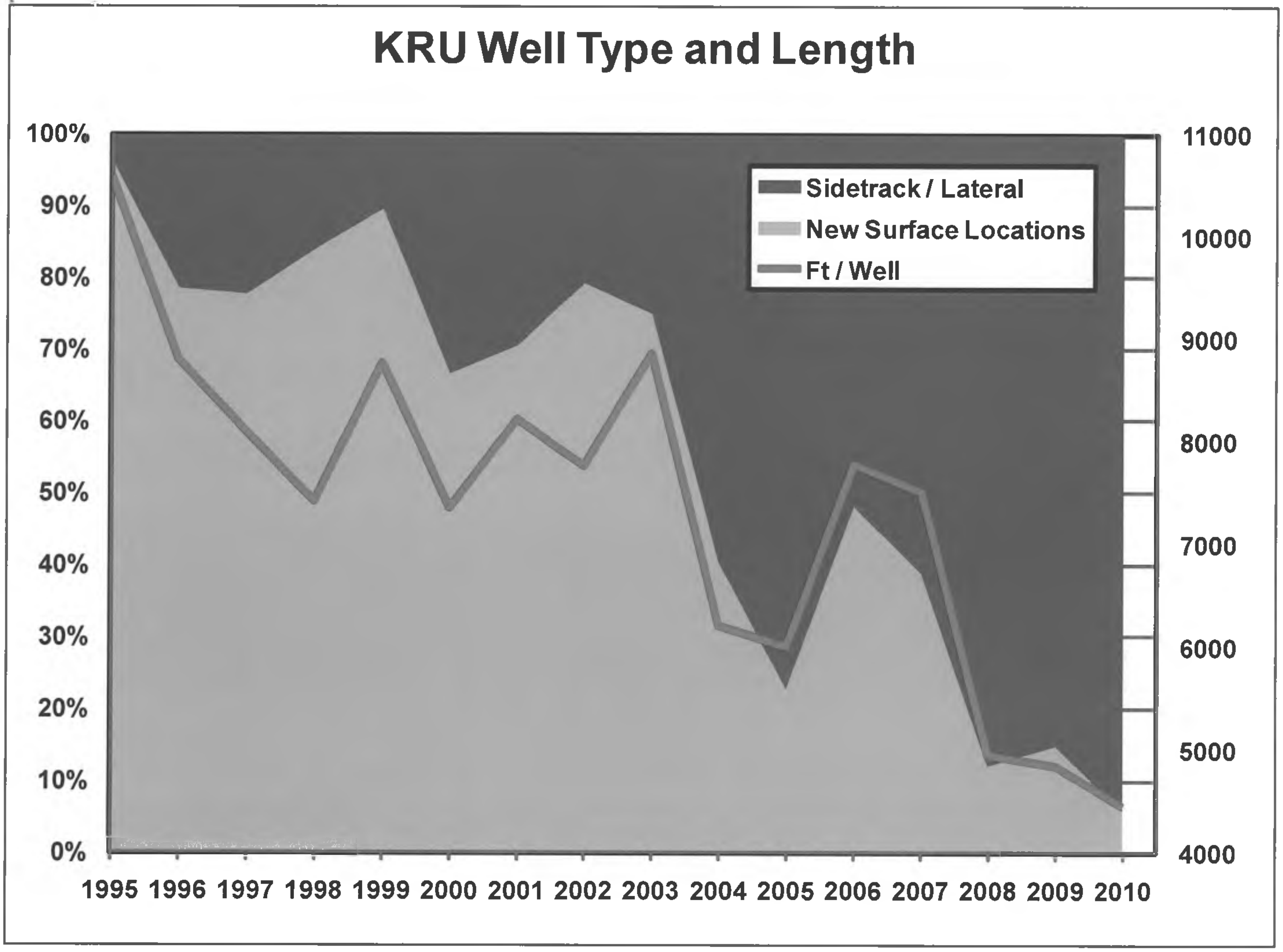
Purple shows the satellite sidetracks; 100 to date and growing.

As in the case of Prudhoe Bay, we can see how the average footage per well drops significantly as percentage of sidetracks increases.



This graph expands the black wedge from the previous slide, showing only new wells. As in the case of Prudhoe Bay, we can see how the development of satellites start and finish as wells have been drilled and the project completed.

Growth here comes from new projects being added .



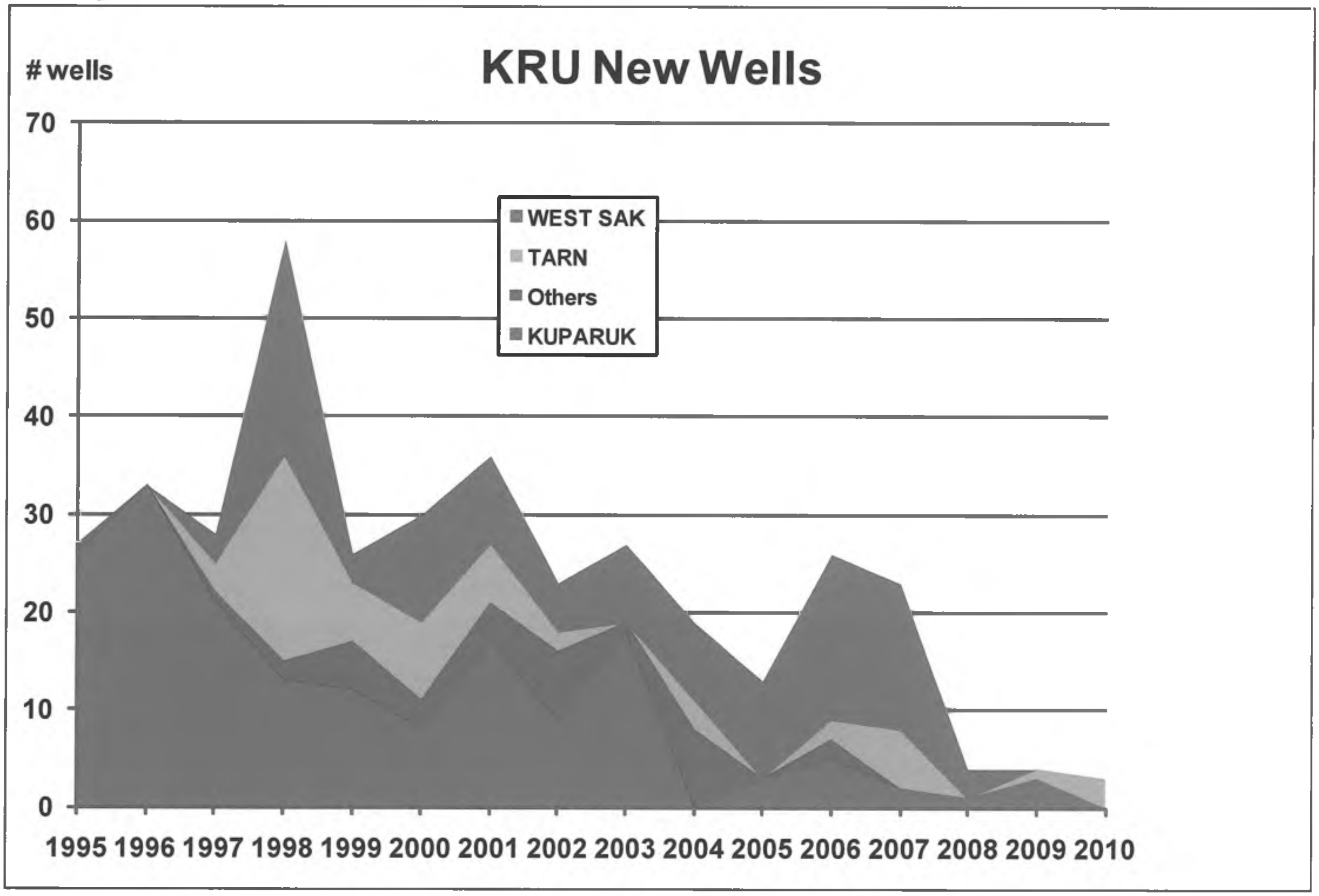
The above graph shows grassroots wells (light blue) as percentage of total wells (dark blue is sidetracks).

In the mid-1990s, about 95 percent of the wells in the Kuparuk River Unit were grassroots wells, with an average length of over 10,000 feet.

Today, only 15 percent of the wells in the Unit are grassroots wells. The average length of a well is 5,000 feet.

This does not point to diminished drilling, but *different drilling*. Sidetracking existing downholes means lower cost (no new facilities, no new gravel pads). Together with greater efficiency in drilling technology this all means lower associated cost for the developer).

As in the case of Prudhoe Bay, we can see the correspondence between sidetrack percentage and feet per well.

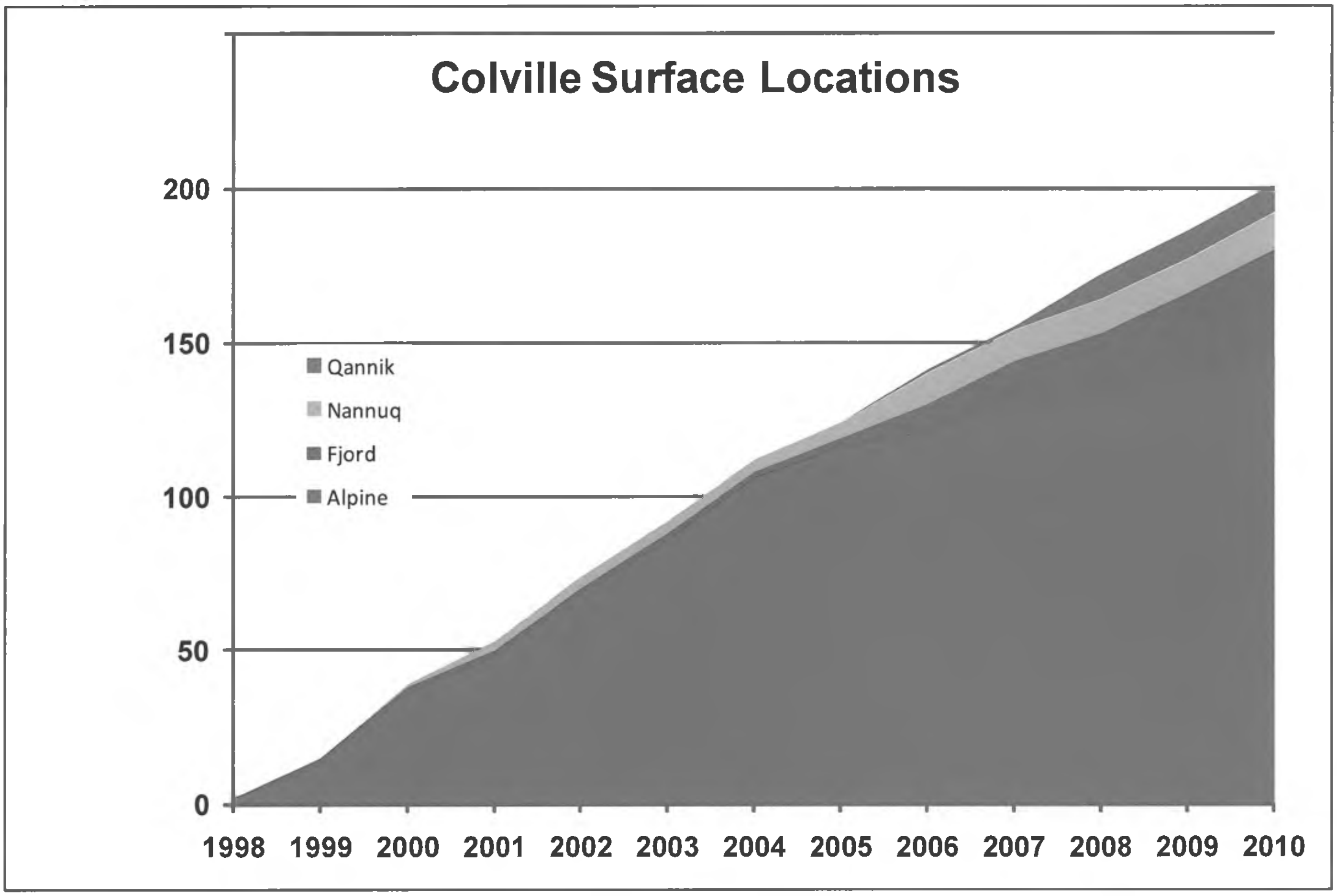


Approximately 5 new wells have been drilled per year in the Kuparuk River Participating Area since 2004. As is the case in Prudhoe Bay, most grassroots drilling has happened in the satellites.

Most satellite development has been in West Sak during this time period. West Sak reservoirs are also produced from the newly formed NEWS (North East West Sak) Participating Area (formed in 2009). Due to budget constraints, ConocoPhillips is not planning any new wells for 2009-2010.

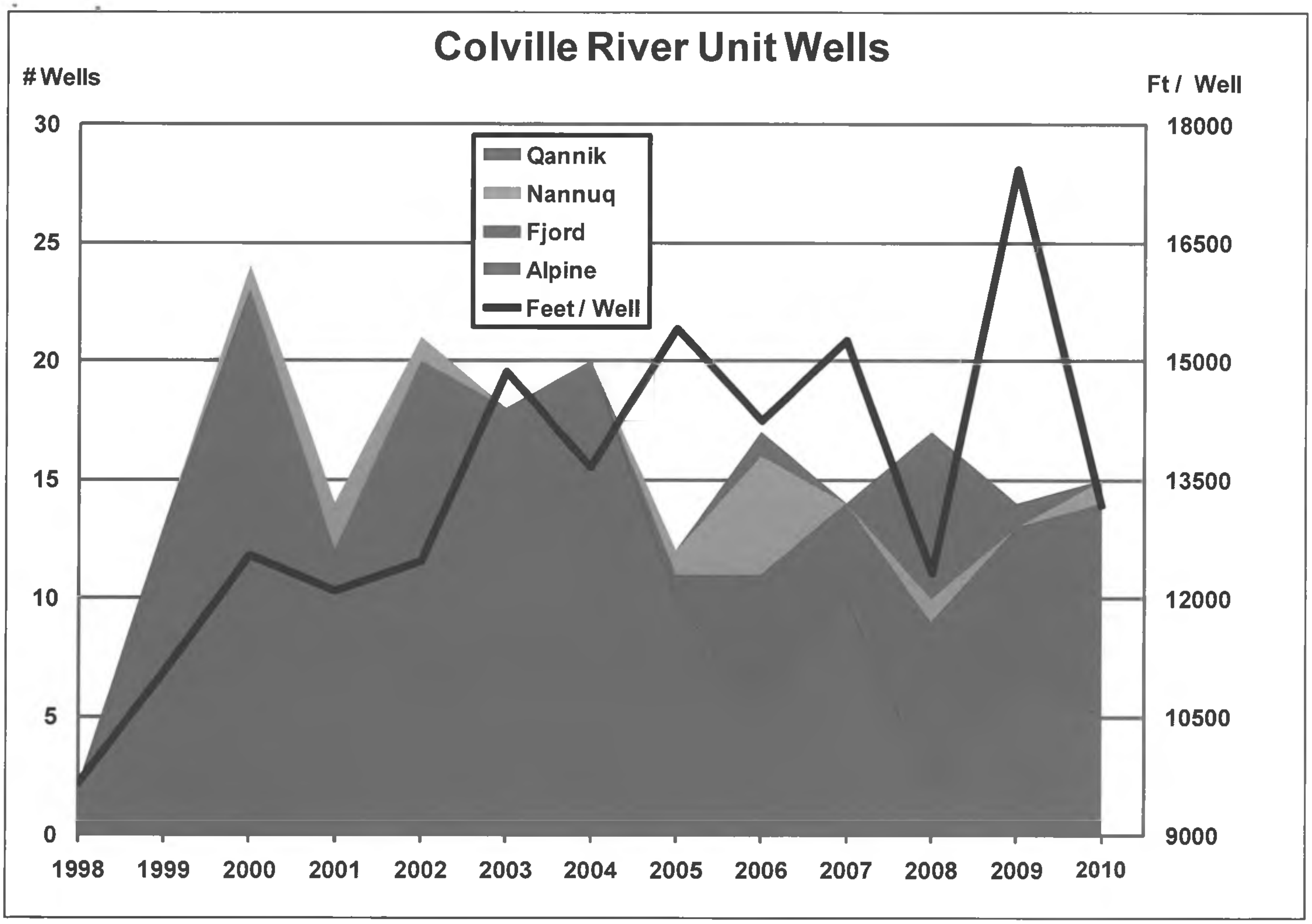
Tarn PA is planning for three new wells within the 2009-2011 timeframe.

Future development in the Kuparuk River Unit wil include horizontal, multilateral and coiled tubing drilling to access incremental reserves at reduced cost.



The Colville River Unit graphs show another part of the story -- how development of a field looks at an earlier stage, in comparison to the older fields at Prudhoe Bay and Kuparuk.

The cumulative plot shows a consistent growth in wells drilled, and also how the main area is developed before satellites are added.



Here, again, we can see how Alpine was developed first, and how most development in the past few years are for satellites. Alpine is developed, and needs new pads to the west, which will not happen without a bridge.

The black line shows feet per well increasing over time. The decline in 2008 is due to development of satellites.

Compared to Prudhoe Bay and Kuparuk, we see fewer sidetracked wells. This is due to the stage of the development (Colville River Unit being newer).

Without the bridge, we can expect fewer wells in the future, although some development to the east is possible.

2000 - 2009

- Ongoing drilling in the Prudhoe, Kuparuk, and Milne Point fields.
- Northstar came on line late in the year 2000.
- Schrader Bluff development of S-pad at Milne Point and the Polaris satellite at Prudhoe also came online during the same time frame. Continued Ivishak drilling within Prudhoe Bay,
- 2004 drilling activity reflects extensive drilling in the Orion and Polaris satellites in Prudhoe Bay
- West Sak development drilling in Kuparuk, and
- Extensive drilling in the Colville River Unit (CRU).

Drilling in all these areas continue today as companies use new technology to extract more oil out of the reservoirs, as illustrated by the below graph and table.

Drilling Activity 2000 - 2009

- 1,284 total number of wells drilled (Count includes lateral, sidetrack, and pilot hole wells)
  - 80 Exploration Wells
  - 1,204 Development Wells
- There are two categories for development wells:
  - wells = horizontal, laterals, pilot holes, and conventional (straight & deviated)
  - plugbacks

Prudhoe Bay Unit

- Initial Participating Areas (Ivishak)
  - 323 wells
  - 58 plugbacks
- Aurora Participating Area (Kuparuk formation)
  - 11 wells
  - 6 plugbacks
- Borealis Participating Area (Kuparuk formation)
  - 17 wells
  - 12 plugbacks
- Lisburne Participating Area
  - 9 wells
  - 1 plugback
- Niakuk Participating Area (Kuparuk formation)
  - 4 wells
  - 3 plugbacks
- Orion Participating Area (Schrader Bluff formation)
  - 75 wells (included in this total are 32 lateral wells)
  - 22 plugbacks
- Polaris Participating Area (Schrader Bluff formation)
  - 16 wells (included in this total are 5 lateral wells)
  - 1 plugback
- Put River Pool (Kuparuk age equivalent)
  - 1 well
  - 1 plugback
- Raven Participating Area (Sag River formation)
  - 2 wells
- Ugnu wells
  - 6 water disposal wells
- Pt McIntyre Participating Area
  - 11 wells
  - 8 plugbacks

Milne Point Unit

  - 5 exploration wells
  - 2 disposal wells
- Kuparuk Participating Area
  - 17 wells
  - 4 plugbacks
- Schrader Bluff Participating Area
  - 42 wells (included in this total are 16 lateral wells)
  - 9 plugbacks
- Ugnu wells
  - 4 wells

Endicott Unit

- 1 well in the Sag River formation
- 8 wells Kekiktuk

NPR-A

- 14 Exploration wells (Conoco)
- 8 exploration wells (FEX)

Colville River Unit

- 1 exploration well (Char)

- Alpine Participating Area
  - 33 wells drilled
  - 12 plugback wells
  - 8 lateral Wells
- Fiord Kuparuk
  - 7 wells drilled
  - 5 plugbacks
  - 1 lateral
- Fiord Nechelik
  - 11 wells
  - 2 lateral wells
- Nanuq Kuparuk
  - 9 wells
  - 2 plugbacks
  - 3 laterals
- Nanuq Nanuq
  - 7 wells
  - 1 plugback
- Qannik
  - 9 wells
- Nechelik Tract Operation
  - 1 well in 2009

Kuparuk River Unit

  - 1 exploration well south of KRU (Antigua in 2006 – Kuparuk target)
- Kuparuk Participating Area
  - 144 wells
  - 26 plugbacks
- Meltwater PA
  - 9 wells
- Tabasco PA
  - 2 wells
  - 3 plugbacks
- Tarn PA
  - 17 wells
  - 1 plugback
- West Sak PA
  - 7 wells labeled exploration (of which 2 are plugbacks)
  - 123 wells (included in total are 72 lateral wells)
  - 75 plugbacks
- ENI drilled south of KRU
  - 3 exploration wells

Northstar Field

- 13 wells
- 4 sidetracks

Oooguruk Field

- 1 exploration well in the Torok formation
- 1 disposal well
- 4 Kuparuk wells
- 7 Nuiqsut wells

Nikaitchuq field

- 17 exploration wells (of which 7 are plugbacks)

Badami Unit

- 2 exploration wells (Kupcake and Red Wolf B1-38 Kekiktuk well
- Reentering B1-18 Badami development well

Beechey Point

- 5 exploration wells

Outside established Units

- West of Kuparuk River Unit
  - 1 exploration well (Cronus)
  - 3 exploration wells (Tofkat)

- South of Kuparuk River Unit
  - White Hills, 5 exploration wells
  - 1 hydrates testing well (Hot Ice)

- North of Prudhoe Bay Unit
  - 4 exploration wells (Sag River, North Shore)

- South of Prudhoe Bay Unit
  - 2 exploration wells (Jacob's Ladder)
  - 1 exploration well (Hailstorm)

- Foothills Area
  - 7 exploration wells

Red Dog Mine

- 6 wells to supply gas to Red Dog mine

US Government DOI
Coal Bed Methane Exploration Program

- 8 in Wainwright
- 1 in Franklin Bluffs

Alaska Oil and Gas Association

AOGA

121 W. Fireweed Lane, Suite 207
Anchorage, Alaska 99503-2035
Phone: (907)272-1481 Fax: (907)279-8114
Email: crockett@aoga.org
Marilyn Crockett, Executive Director

COMMENTS OF THE ALASKA OIL AND GAS ASSOCIATION
ON HB 110
HOUSE RESOURCES COMMITTEE
FEBRUARY 16, 2011

The Alaska Oil and Gas Association (AOGA) appreciates the opportunity to express its support for HB110, the Governor's proposed amendments to the ACES production tax. We sincerely believe these provisions, when enacted into law, will increase the competitiveness for investment dollars in Alaska, resulting in increased job opportunities and the development necessary to stem the decline in oil production currently facing Alaska.

Below are our comments on specific provisions of this legislation:

PROGRESSIVITY RATES/BRACKETING/TAX CAP

AOGA supports the provisions in HB110 which establish bracketing of the progressivity rates and caps progressivity at 25%, for a maximum rate of 50% for progressivity and the base rate combined.

Under the current form of ACES, at $30, the taxpayer pays at the 25% base rate. But as the taxable Production Tax Value (PTV) raises above $30, the progressivity feature kicks in, and instead of applying the higher tax rate to just the incremental dollar, the current tax system reaches back and taxes the entire original $30 at the higher rate. Each time the PTV per barrel increases further beyond $30, all prior dollars are taxed at the higher rate instead of just that further increase. This approach is what creates such high marginal tax rates, and creates an imbalance in the risk-reward investment environment in Alaska. Removing the upside to the degree the progressivity feature does makes it much more difficult to compete for investment dollars with other areas that are not as fiscally challenged as investments here in Alaska.

Bracketing sets tax rates for the different levels of PTV so that each level is taxed only once and at a specific rate for that bracket, moderating the impact of ACES' high rate of tax. As you have seen, the bracketing described in HB 110 generally follows the same line of progressivity as in the current version of ACES. But by not reaching back and taxing those dollars that have already added value to the project and that have had taxes paid on them and not taxing them again, HB 110 adds much needed stability and predictability to the tax. As companies realize higher prices and greater PTV, the State likewise continues to share in those benefits.

Bracketing of income to pay taxes is a time-tested approach. There isn't a person here that doesn't have a personal interest in the concept and how it works. Just look to your personal income taxes with the IRS. The difference between what we are currently experiencing with ACES' progressivity feature and the notion of bracketing is quite compelling. Under ACES, as you've heard already from the DOR and in a number of presentations and publications over the last year, the rate is too high.

In addition, capping progressivity and the base tax at the 50% combined rate under HB 110, rather than the current 75%, also provides the impetus needed to motivate companies to undertake the high risk projects on which the future economic health of Alaska will depend. This change creates a business climate where the reward is commensurate with the risk and keeps the needs of the State and the producers in a more appropriate balance.

You will be hearing from our member companies regarding this risk/reward and the need for an adequate upside, and the challenges they face when presenting projects to their respective Boards. The competition for these dollars is real and anything to move Alaska to a more competitive position will make those arguments more palatable and possible.

ANNUAL –v- MONTHLY

Another aspect of progressivity is the monthly calculation of the progressivity rate. The inherent flaw in this and why AOGA supports moving to an annual progressivity is simple. The revenues that are used in the calculation of the progressivity are actuals, reflecting current production and current prices. They are subject to the seasonal swings in production or market pressures of price. In calculating the PTV, though, the deductible lease expenditures are the actual expenses for the whole year, with 1/12 of the annual total being allocated to each month during the year. In other words, the present version of progressivity creates a huge mismatch by using each month's *actual* gross value at the point of production (GVPP), but deducting 1/12 of the actual expenses. This result is achieved at the annual true-up on March 31st of the following year. In making estimated monthly payments, however, the mismatching is compounded because taxpayers have the actual GVPP for each month but will have to rely on a monthly figure for the *estimated* lease expenditures for the whole year, in order to calculate the PTV and the resulting progressivity rate for that month.

The monthly approach to progressivity actually taxes artificial PTV, raising the Alaska tax rates higher than reported on any graph of tax rates. None of those graphs account for mismatching in the progressivity tax on monthly PTV. The difference is solely driven by the fact that progressivity taxes the inflated, incorrect monthly PTV resulting solely from this mismatching. We support moving from a monthly calculation of progressivity to an annual calculation to synchronize the revenues with the expenses, avoid the mismatching, and more accurately reflect the philosophy behind what a progressivity feature should look like.

TAX CREDIT INCENTIVES EXTENDED TO NORTH SLOPE

Sections 15 and 16 of HB 110 expand the existing 40 percent *well lease expenditure* tax credit currently available only to qualifying expenditures in "Middle Earth" and the Cook Inlet Sedimentary basin,[1] so it will also be available for qualified expenditures made on leases or properties north of 68 degrees North Latitude. Under HB 110, this change would be effective January 1, 2012, for expenditures after December 31, 2011.

The well lease expenditure concept was introduced and enacted into law in May 2010 in connection with chapter 16, 2010 Session Laws of Alaska (the Cook Inlet Recovery Act). Under AS 43.55.023(o) a well lease expenditure (WLE) is defined as:

> a qualified capital expenditure and an intangible drilling and development cost authorized under 26 U.S.C. (Internal Revenue Code), as amended, and 26 C.F.R. 1.612-4, regardless of the elections made under 26 U.S.C. 263(c) . . . [2]

A well lease expenditure is the subset of qualified capital expenditures (QCE) that currently define the scope of capital spending that qualifies for the 20% QCE credit under sub-section .023(a). Thus, within the QCE "bucket" are a set of costs that would be eligible for a full 40% tax credit instead of the usual 20% QCE credit. The definition of WLE as *intangible drilling and development cost* (IDC) has several advantages. First, IDC is a concept that is well-defined in oil and gas tax law. IDC is designated for

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[1] i.e., South of 68 degrees North Latitude under AS 43.55.023 (l) and (n).

[2] The full language under subsection .023(o) reads as follows:

> (o) For the purposes of (m) and (n) of this section, a well lease expenditure incurred in the state south of 68 degrees North latitude is a lease expenditure that is
>
> > (1) directly related to an exploration well, a stratigraphic test well, a producing well, or an injection well other than a disposal well, located in the state south of 68 degrees North latitude, if the expenditure is a qualified capital expenditure and an intangible drilling and development cost authorized under 26 U.S.C. (Internal Revenue Code), as amended, and 26 C.F.R. 1.612-4, regardless of the elections made under 26 U.S.C. 263(c); in this paragraph, an expenditure directly related to a well includes an expenditure for well sidetracking, well deepening, well completion or recompletion, or well workover, regardless of whether the well is or has been a producing well; or
> > (2) an expense for seismic work conducted within the boundaries of a production or exploration unit.

special tax treatment under the U.S. Internal Revenue Code.[3] It represents the part of capital expenditures that has no physical attributes or salvage value, such as fuel, labor and rig rental. Thus it is a convenient and readily accessible accounting designation.

Second, WLE is consistent with language already existing in the PPT-ACES framework. Producers will not have to wait for the DOR to write regulations that describe what is included and not included in the WLE.

Third, IDC is focused on costs associated with drilling wells and getting more production out of both existing fields and new field development. As stated in sub-section .023(o)(1), well lease expenditures include "well sidetracking, well deepening, well completion or recompletion, or well workover expenditures" that would target new areas of the reservoir.

Lastly, since labor costs may be included in IDC, the 40% WLE credit indirectly supports hiring and job creation.

In sum, AOGA strongly endorses this special category of QCE that is targeted for the credit uplift because 1) this category of expenditure is tied directly to in-field drilling; 2) includes labor costs; and 3) is a convenient and readily accessible accounting designation. Also, this proposal has the advantage of an earlier effective date compared with other provisions in HB 110, thus potentially jump-starting production sorely needed to stem the production decline in the near-term.

EFFECTIVE DATES

AOGA is concerned about the delayed effective dates of the major components in this legislation. The only sections of this bill that become effective this year are the ones making the interest rate mirror more appropriately the current cost of money. In 2012, the amendments to the tax credit provisions become effective. The following year the progressivity provisions become effective. Finally, in 2014 the statue of limitations shifts from six years to four.

All the data you will see shows Alaska is losing on the activity and investment front when compared to the rest of the world. The delay of these effective dates, even in a staggered fashion, doesn't reflect the urgency of the need for this legislation and in fact protracts any commercial decision out over the next few years. As you know, decisions on the magnitude of these investments don't happen overnight. The competition for the available dollars is quite intense. To get final approval of the dollars, mobilize the rig, develop the kit and come to ultimate production could be three years or more.

[3] Intangible well costs are distinct from tangible costs such as equipment and drill pipe and are 70-100 percent deductible against federal taxable income when incurred. (See *Petroleum Accounting: Principles, Procedures, & Issues*, 5th Ed. (University of North Texas: PriceWaterhouseCoopers), p.72.

Industry believes the need to move forward is more urgent than what the bill is stating. We do not believe these staggered effective dates are an impediment to having a good bill, but without the delays it would be a better one.

LOWER TAX RATES FOR NEW FIELD DEVELOPMENT

HB110 includes provisions (under Sections 6 and 8) that would lower the base tax rate from 25% to 15% for oil and gas produced from areas outside of current fields and units or not in commercial production prior to December 31, 2010.

In addition, the progressivity surcharge for oil and gas produced from areas outside of current units would be capped at 40%, or 25% above the base tax rate. And progressivity would be subject to parallel tax-bracketing treatment, where tax rates for a particular discrete tax bracket are applied only to incremental income in that bracket. Also, the progressivity tax is levied on an annual basis instead of monthly, the same as for the fields in production. This change would be effective January 1, 2013, and apply to production after December 31, 2012. The proposed base and progressive tax rates applicable to existing and new field development are summarized in Exhibit 1, below.

Exhibit 1. Summary of Proposed Base Tax and Progressivity Surcharge for New and Existing Fields

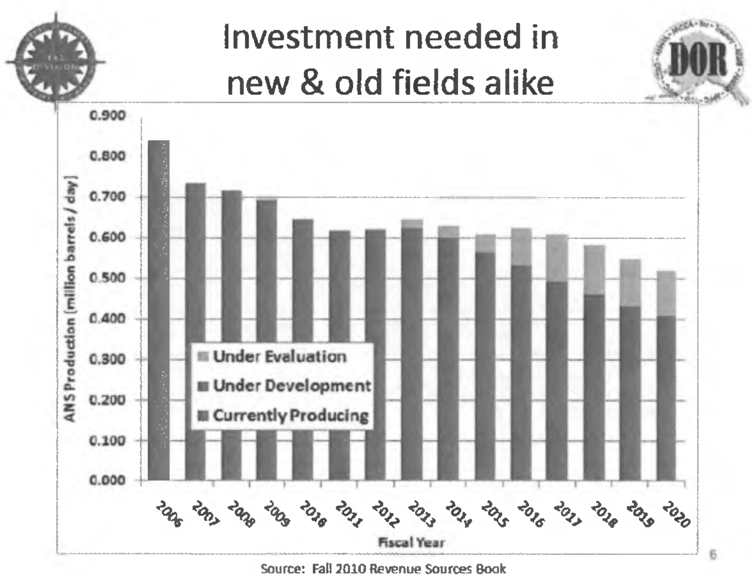
Taxable Production	Field or Unit In Production Prior to 31-Dec-2010	Field or Unit In Production After to 31-Dec-2010
Base Tax	25%	15%
Max Progressive Surcharge	25%	25%
Max Combined Tax Rate	50%	40%
Progressivity Annual instead of Monthly	Yes	Yes
Bracketing Applies	Yes	Yes
Effective Date	1-Jan-2013	1-Jan-2013

AOGA cautiously supports this proposal for new field development, which represents a significant reduction in the implied tax burden. However, it raises several questions. First, as with other provisions in HB110, the implied lag in the effective date is problematic. If, as the administration has indicated in its testimony, there is a degree of urgency with regard to the need for investment in the oil patch, then why delay? Why encourage companies to build lags into their own investment planning?

Second, the DOR *Fall Revenue Sources Book* anticipates production from new developments from state and federal lands to account for a significant portion of total ANS production over the next decade. (See Exhibits 2 and 3, below.) But almost all of these areas of potential new field development overlie existing producing fields and/or units. Would new field development from these areas qualify for the lower base tax and progressivity schedules contained in Sections 6 and 8 of HB110? Providing an answer to this question by regulations could be a drawn-out, difficult process — assuming they could be drafted in a way that provides the answer while remaining consistent with the statute.[4]

Third, the provisions in sections 6 and 8 of HB110 are silent on the treatment of lease expenditures for new field development. Since the proposed change in base tax and progressivity is driven by the PTV associated with new field development, some form of ring-fencing production, revenue and costs is implied. This in turn raises questions about the complexities of allocating joint operating and capital costs. AOGA favors addressing the matter of cost allocation in statute rather than through regulation.

Exhibit 2. DOR Commissioner's Presentation to the House Resources Committee, February 7, 2011



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[4] AS 44.62.030: "a regulation adopted is not valid or effective unless consistent with the statute" that it is "implement[ing], interpret[ing], mak[ing] specific, or otherwise carry[ing] out.

Exhibit 3. Areas of New Field Development over Next Decade

1. State lands
    a. Expanded heavy/viscous oil development
        i. West Sak
        ii. Orion
        iii. Polaris
        iv. Schrader Bluff fields
    b. Continued satellite development at Alpine
        i. Fiord
        ii. Nanuq
        iii. Qannik fields),
    c. New developments
        i. Oooguruk
        ii. Nikaitchuq
    d. Point Thomson – startup in 2015
    e. Badami - Restart 4Q 2010
2. Federal lands
    a. NPR-A,
        i. Alpine West field (start up in the 2013)
        ii. Mooses Tooth unit
        iii. Umiat field.
    b. Liberty development 1Q 2012
    c. Nikaitchuq field start-up 1Q 2011

Lastly, and most importantly, AOGA reminds lawmakers that it is important to incentivize ALL new oil. This means new oil associated with new field development and from exploration, as well as new oil from existing producing fields using in-field drilling, secondary recovery, and tertiary recovery techniques. If attracting investment in the near term is the goal, then AOGA respectfully urges consideration of extending the new field incentives in sections 6 and 8 to any and all new oil development, including that arising from existing fields.

Reducing the Interest Rate on Tax Under and Over Payments and the Statute of Limitations

AOGA supports the proposed reductions to the statutory interest rate on tax under and over payments and the statute of limitations for performing tax audits. We are pleased to see the Administration and particularly the Department of Revenue recognize the need to address these two provisions and their negative impacts on Alaska's investment climate.

Currently the state's interest rate applicable on tax under or over payments is the greater of the federal funds rate plus five percentage points, or 11%, whichever is greater, compounded quarterly. Interest rates in other states are much lower.

The time period for which the Department can audit a taxpayer's tax return is three years from the date of the filing of the tax return for all taxes except for the production tax. With the enactment of ACES, the statute of limitations for auditing production tax returns was increased to six years. We never understood why that change was needed when the three-year audit period has worked successfully for all other taxes and can be extended and re-extended any number of times as appropriate and taxpayers were generally willing to do so.

The longer an audit is allowed to run, the greater the amount of interest there will be that accrues on any underpayment claimed in the audit. Under the current interest rate provisions, after three years, interest represents at least 38¢ for each dollar of additional tax claimed. But after six years the accrued interest grows to at least 92¢ for each dollar of additional tax claimed. The longer statute of limitations and high interest rates mean a greater likelihood that audit disputes will be litigated instead of settled, because the interest, which under state law cannot be compromised or abated, represents such a substantial portion of the amounts at issue even at the very beginnings of the disputes.

Reducing the interest rate provisions to the lower of the federal fund rate plus three percent or 11%, and shortening the statute of limitations from six years to four, are both clear steps in the right direction to improve Alaska's tax regime. They are long overdue. AOGA supports both proposed changes.

Minimum Tax

A provision of HB 110 which concerns AOGA is increasing the minimum tax on North Slope production.

One element that increases the attractiveness of a tax system is the sharing of risk by the government with the investor, whether the risk turns out well or poorly. Even with the changes to the progressivity tax proposed in HB 110, Alaska would still take a greater share for itself of the upside for price risk. The minimum tax avoids or reduces the State's exposure on the downside of price risk, increasing the risk on investors, thereby making investments in Alaska less attractive.

Complicating this problem is the fact that the minimum tax is imposed on the gross value at the production of the oil and gas, without deductibility of any development or processing costs. Therefore, the minimum tax in essence is akin to a second regressive royalty payment as upstream costs of producing the oil or gas are ignored. The producer could be obligated to pay the tax even when losing money. This disproportionate shift of the investment and price risks to the producer or explorer could result in less investment and premature shut-in and thus lost production and state revenues.

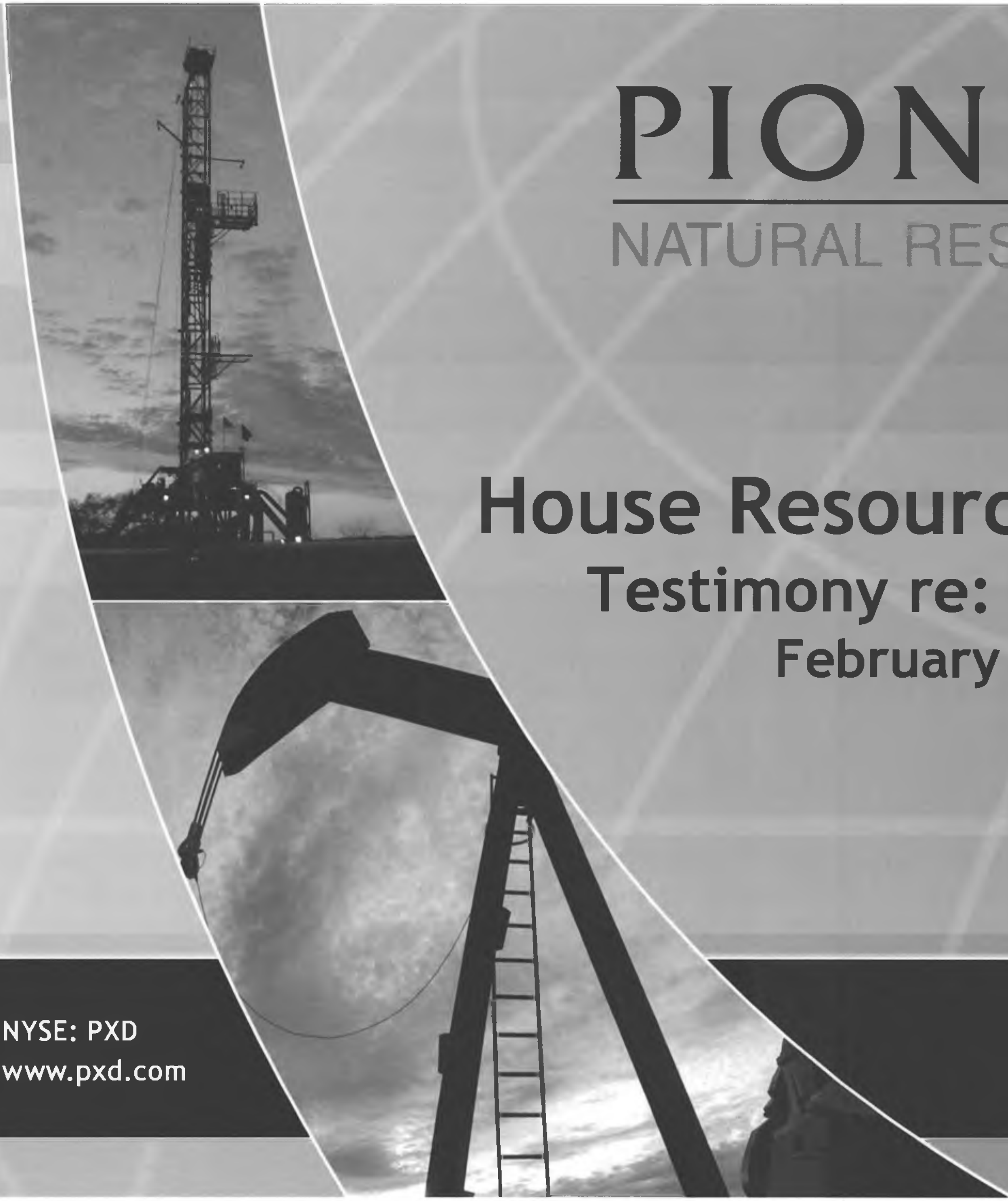
Having a minimum tax along with the high level of progressivity tax has harmed Alaska's investment climate. Further increasing the minimum tax is a step backwards.

It will not increase Alaska's competitiveness and is inconsistent with what the rest of HB 110 is seeking to do.

Again, thank you for the opportunity to submit these comments.

PIONEER

NATURAL RESOURCES



House Resources Committee

Testimony re: House Bill 110

February 16, 2011

NYSE: PXD
www.pxd.com

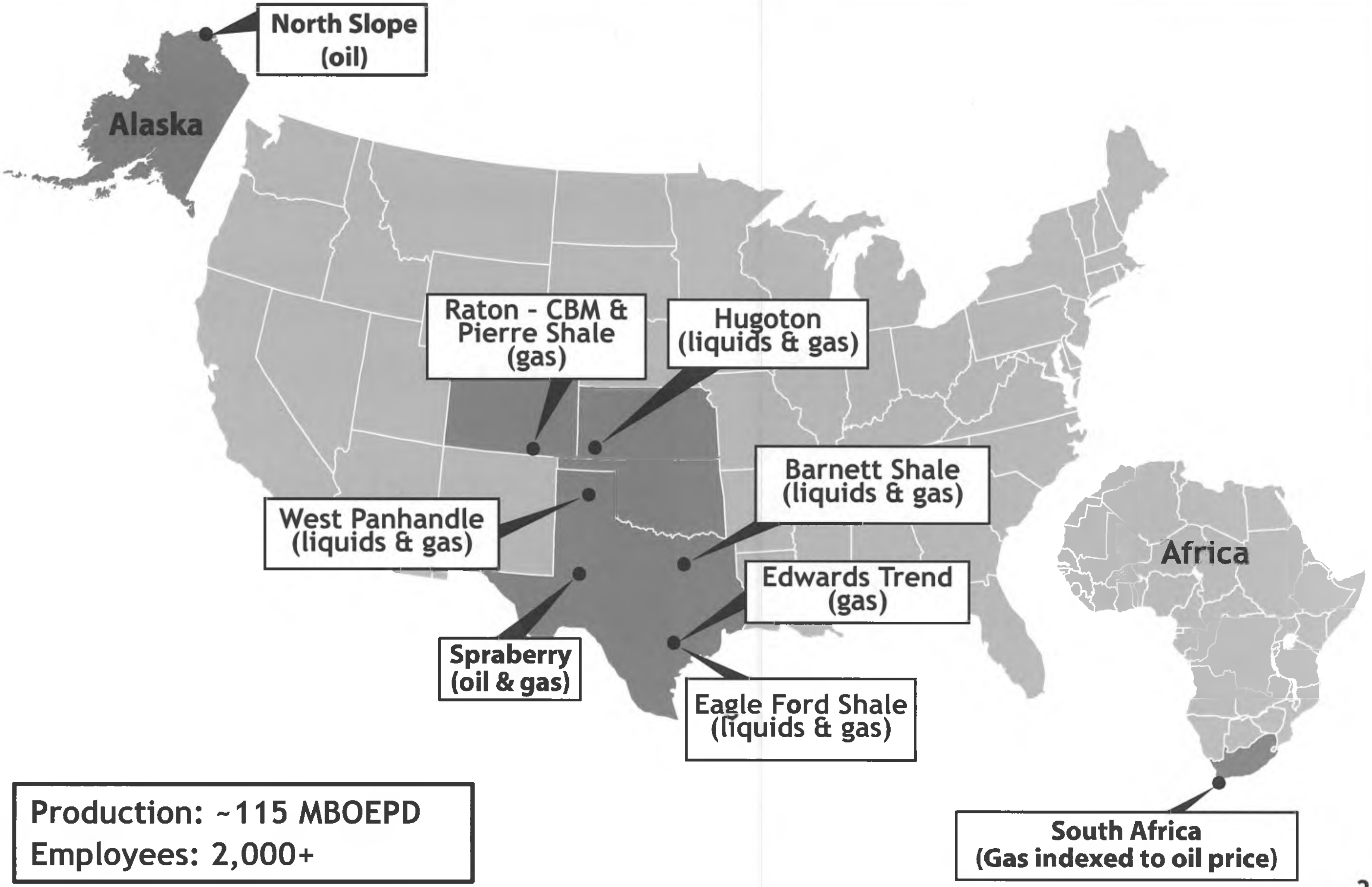
Forward Looking Statements

PIONEER
NATURAL RESOURCES

Except for historical information contained herein, the statements, charts and graphs in this presentation are forward-looking statements that are made pursuant to the Safe Harbor Provisions of the Private Securities Litigation Reform Act of 1995. Forward-looking statements and the business prospects of Pioneer are subject to a number of risks and uncertainties that may cause Pioneer's actual results in future periods to differ materially from the forward-looking statements. These risks and uncertainties include, among other things, volatility of commodity prices, product supply and demand, competition, the ability to obtain environmental and other permits and the timing thereof, other government regulation or action, the ability to obtain approvals from third parties and negotiate agreements with third parties on mutually acceptable terms, international operations and associated international political and economic instability, litigation, the costs and results of drilling and operations, availability of equipment, services and personnel required to complete the Company's operating activities, access to and availability of transportation, processing and refining facilities, Pioneer's ability to replace reserves, implement its business plans or complete its development activities as scheduled, access to and cost of capital, the financial strength of counterparties to Pioneer's credit facility and derivative contracts and the purchasers of Pioneer's oil, NGL and gas production, uncertainties about estimates of reserves and resource potential and the ability to add proved reserves in the future, the assumptions underlying production forecasts, quality of technical data, environmental and weather risks, including the possible impacts of climate change, and acts of war or terrorism. These and other risks are described in Pioneer's 10-K and 10-Q Reports and other filings with the Securities and Exchange Commission. In addition, Pioneer may be subject to currently unforeseen risks that may have a materially adverse impact on it. Pioneer undertakes no duty to publicly update these statements except as required by law.

Pioneer Corporate Profile - 2011

PIONEER
NATURAL RESOURCES



Production: ~115 MBOEPD
Employees: 2,000+

Pioneer Alaska Profile - 2011

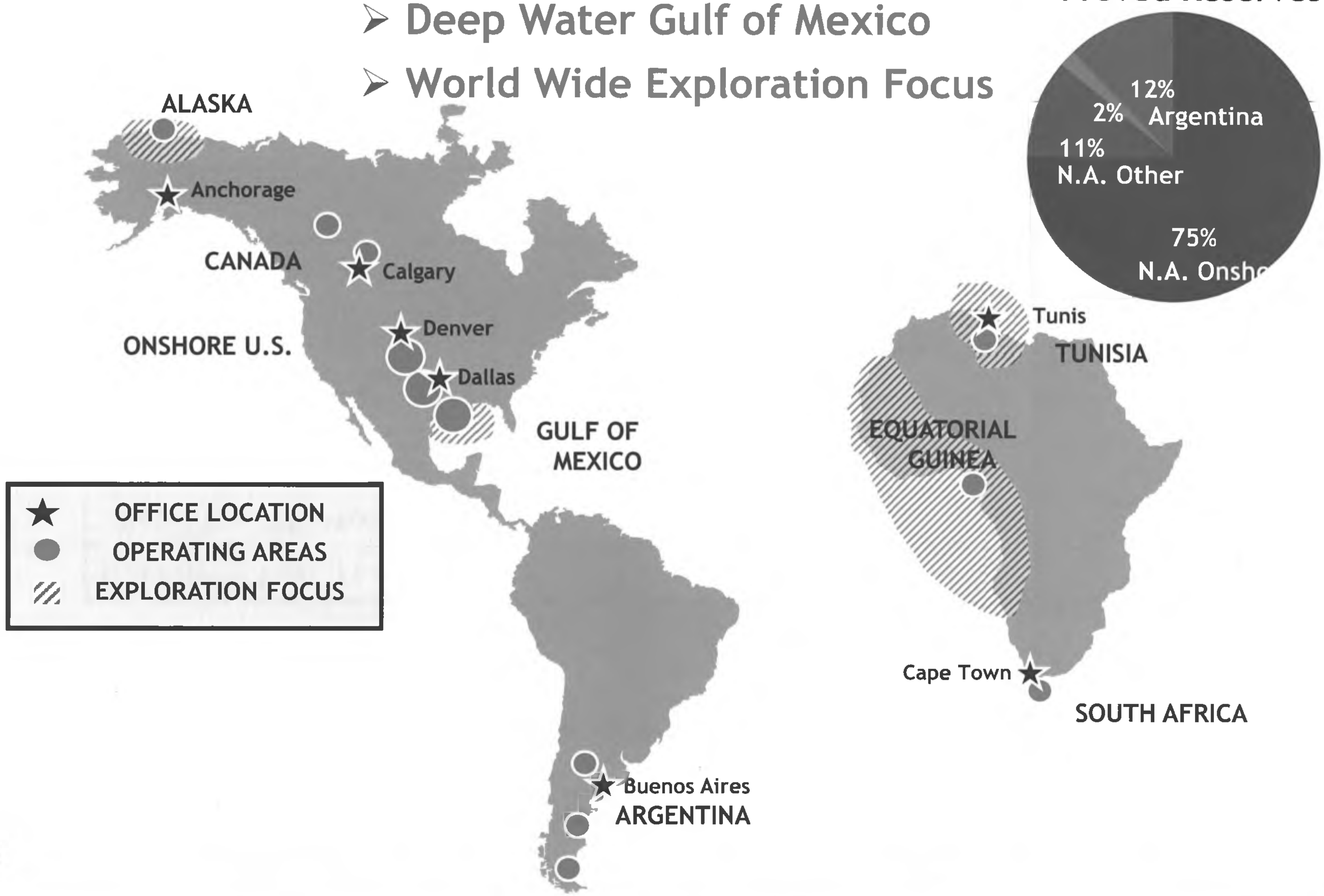
PIONEER
NATURAL RESOURCES

- Anchorage Headquarters
- 60+ Full-Time AK Employees
- ~ 120 AK Contract Workers
- 1st Independent Operator on the North Slope
- World class Oooguruk project
- Challenging environment (North Slope, Offshore)
- State of the art, new technologies
- Higher geologic complexity than close-by analog fields
- Solid support from the State and North Slope producers

Pioneer Natural Resources 2002 - 2003

PIONEER
NATURAL RESOURCES

- US Legacy Asset Development
- Deep Water Gulf of Mexico
- World Wide Exploration Focus



Why Alaska? Scorecard 2002

PIONEER NATURAL RESOURCES

Alaska Relative to Lower 48 Resource Plays:

- Resource

Resource Report Card	Alaska	Lower 48
Resource Potential	✓	
Resource Competition	✓	
Geologic Risk		✓
Oil Bias	✓	
Regulatory Process Ease		✓
Land Acquisition	✓	

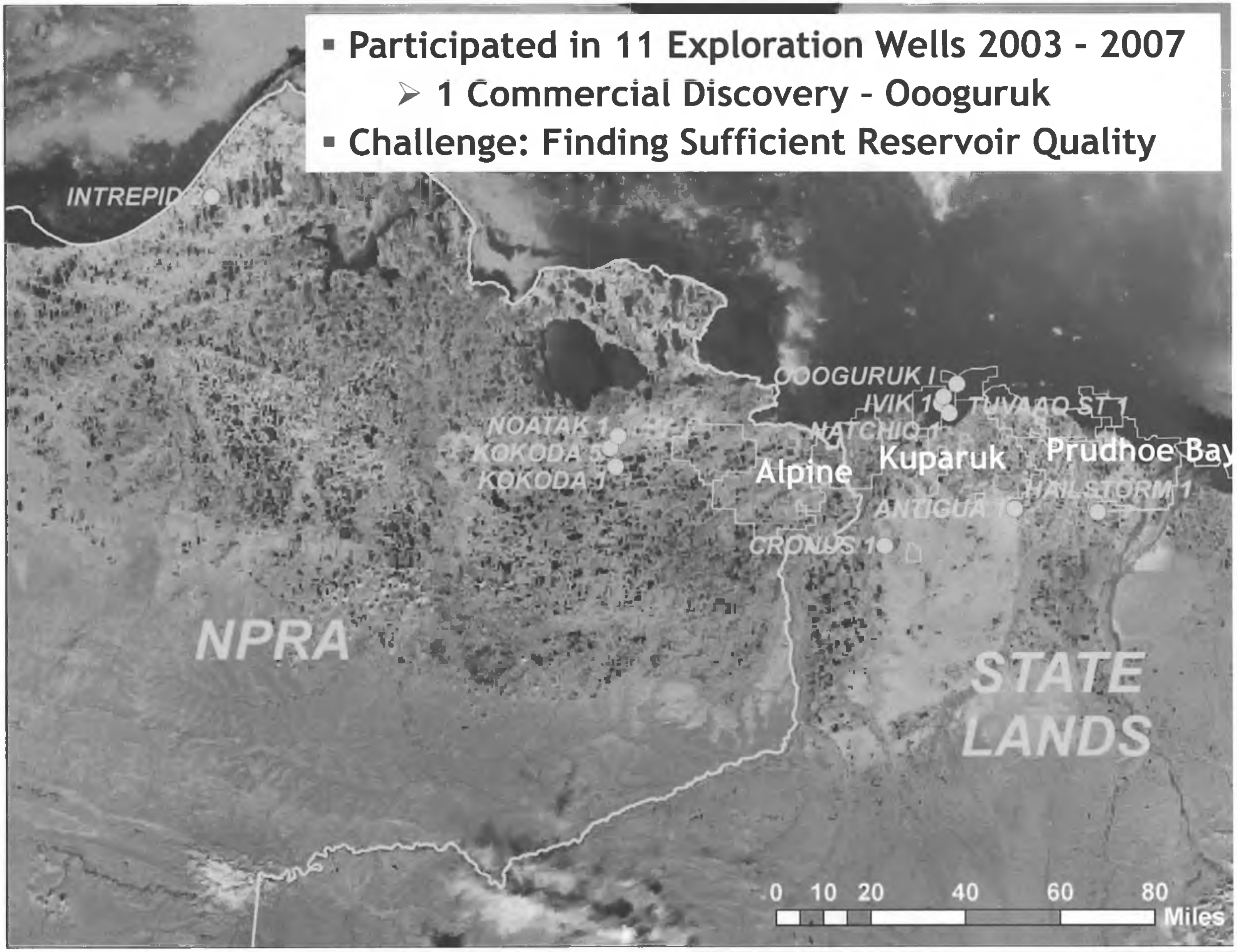
- Profitability

Profitability Report Card	Alaska	Lower 48
Cycle Times / Payback		✓
Execution Risk		✓
Capital Cost		✓
Operating Margins	✓	

North Slope Exploration History

PIONEER NATURAL RESOURCES

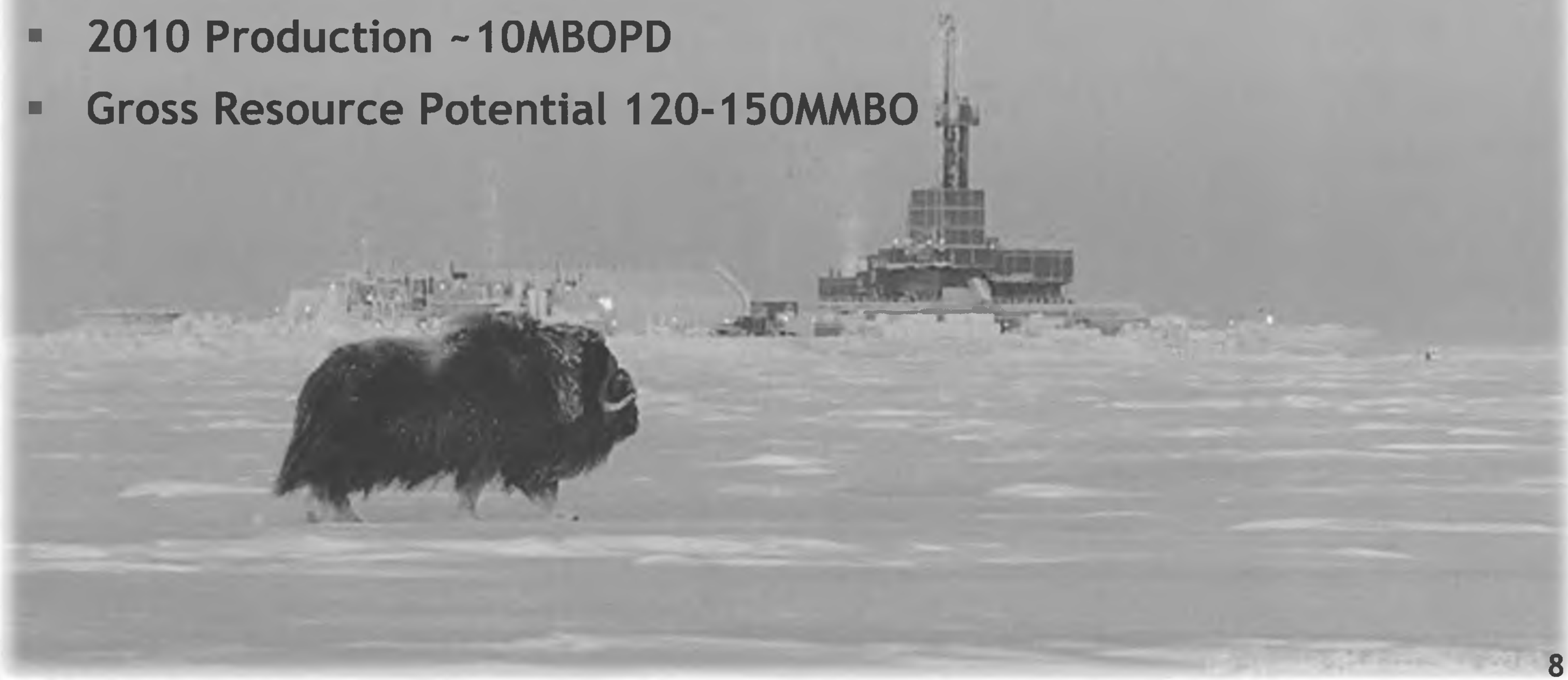
- Participated in 11 Exploration Wells 2003 - 2007
  - 1 Commercial Discovery - Oooguruk
- Challenge: Finding Sufficient Reservoir Quality



Oooguruk Profile

PIONEER
NATURAL RESOURCES

- Total CAPEX ~$1Billion
- 5-Year Project Cycle-Time
- 600+ Jobs at Peak Construction
- First Production June 2008
- 2010 Production ~10MBOPD
- Gross Resource Potential 120-150MMBO



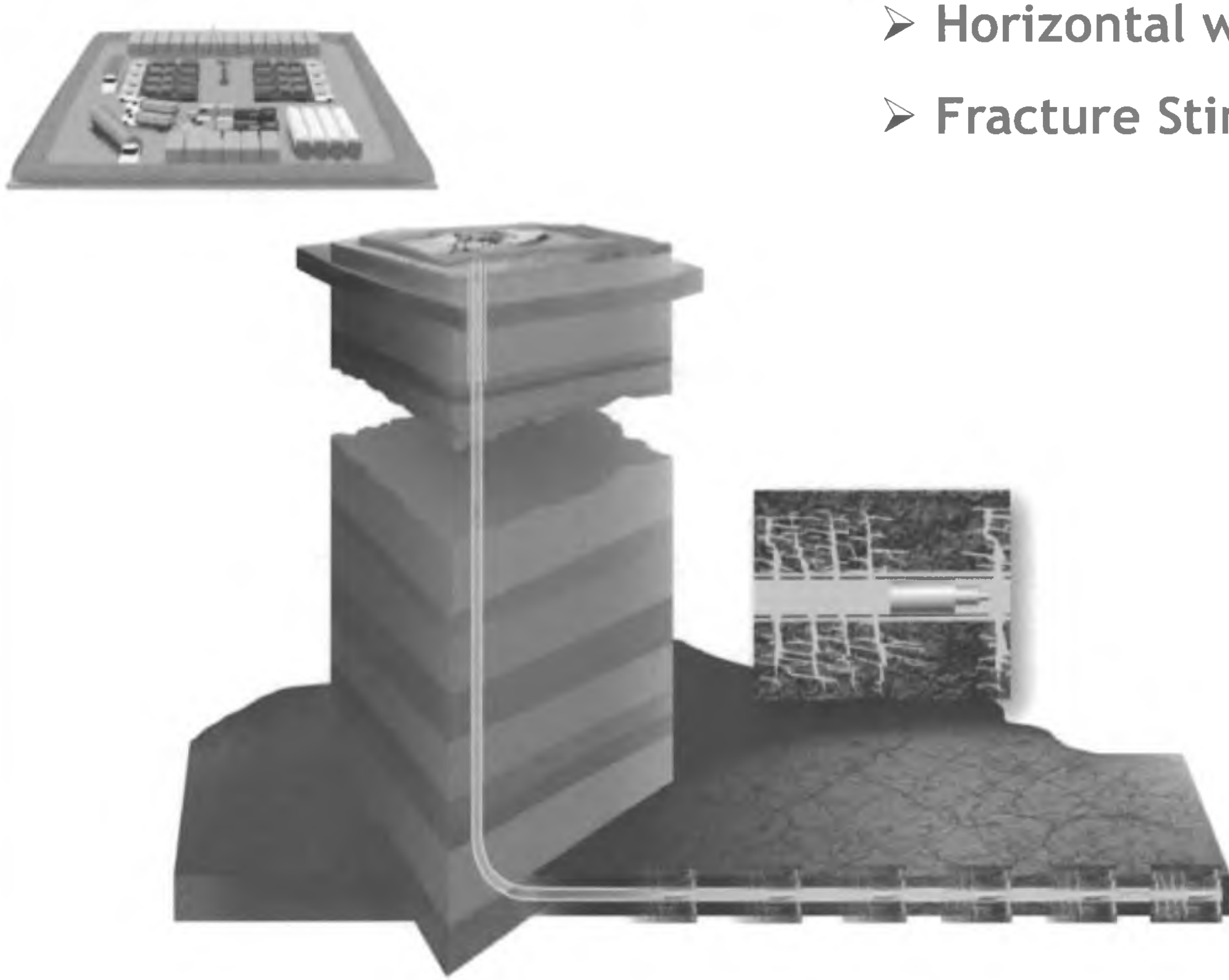
8 Years Later - What has Changed?

PIONEER
NATURAL RESOURCES

- Technology
- Oil and Gas Prices
- Resource Play Development
- Alaska's Severance Tax System

Technology

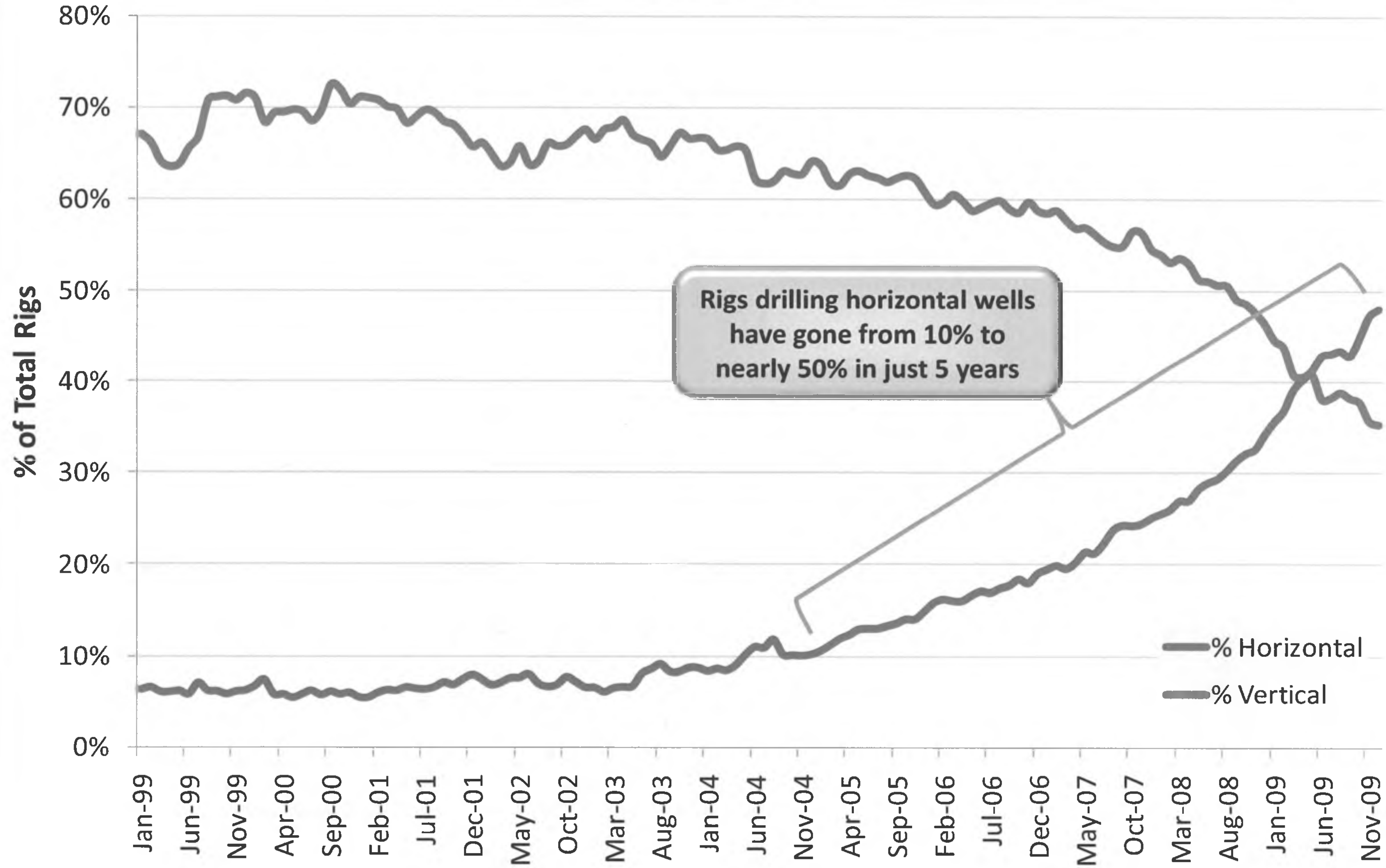
PIONEER
NATURAL RESOURCES



- Horizontal well improvements
- Fracture Stimulation

Growth in U.S. Horizontal Drilling

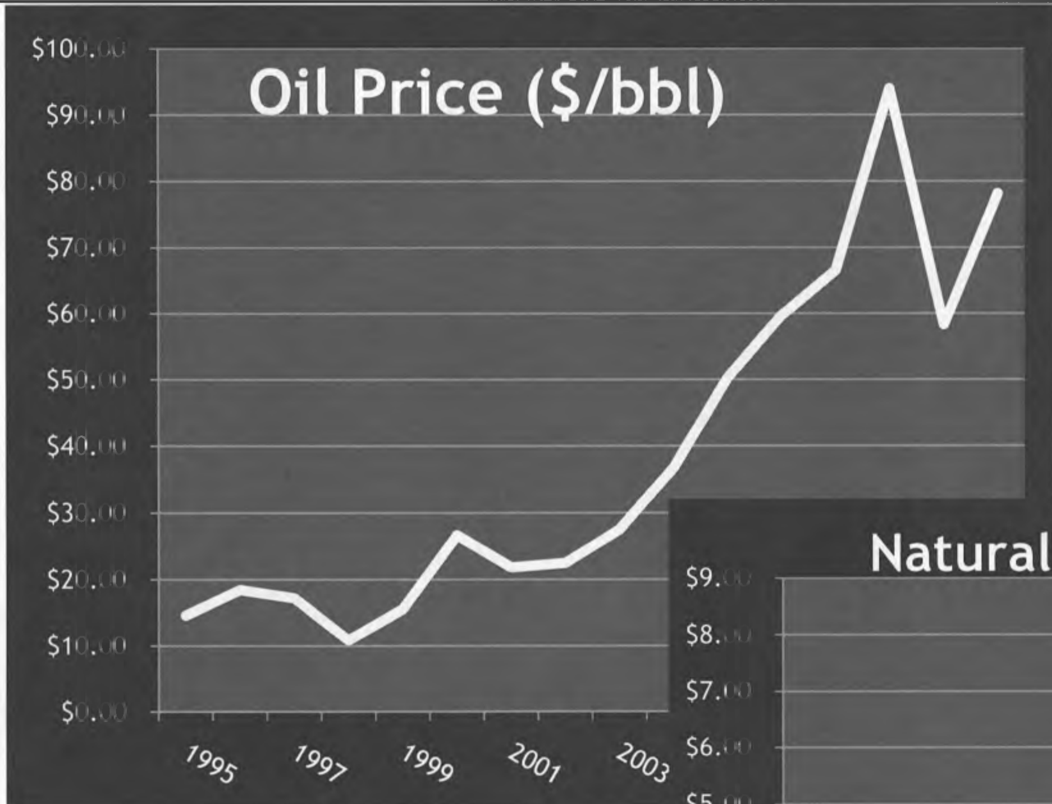
PIONEER
NATURAL RESOURCES

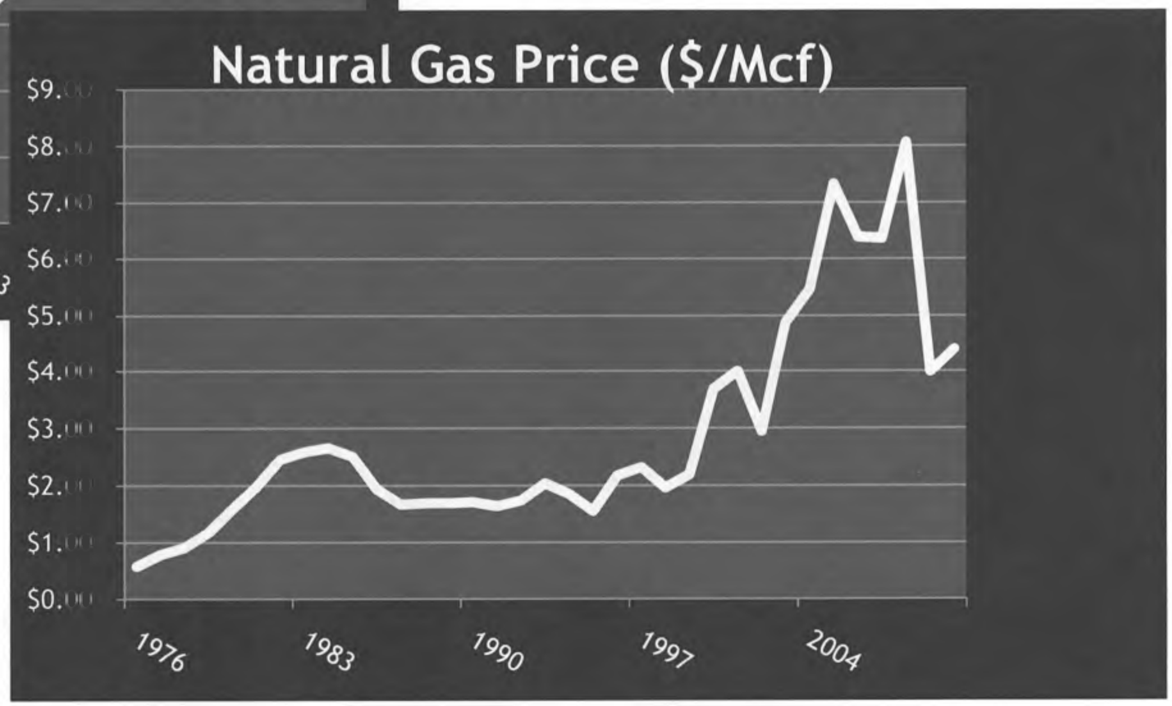


Source: Baker Hughes

Oil and Gas Price History

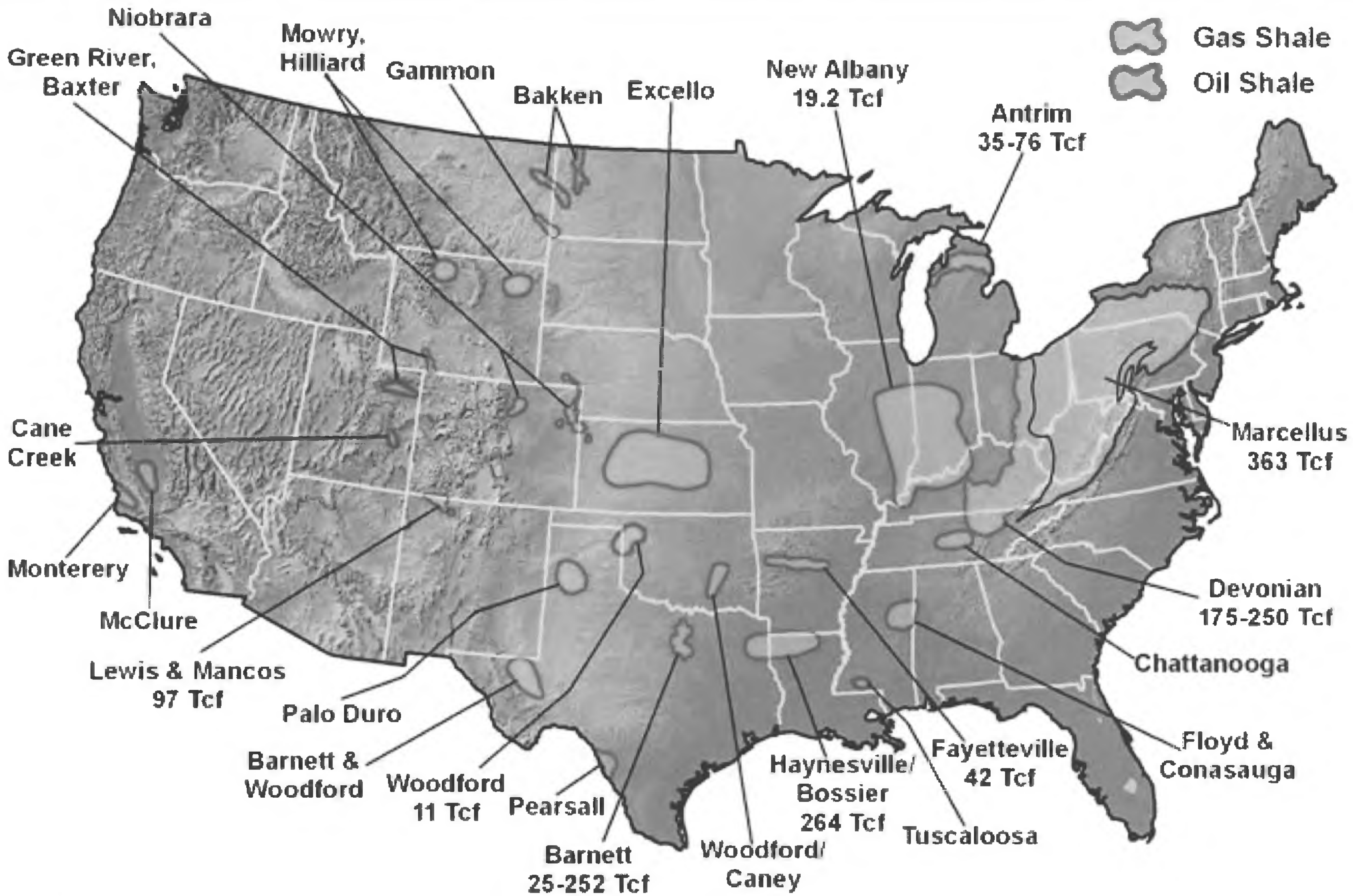
PIONEER
NATURAL RESOURCES





US Shale Resource Plays

PIONEER
NATURAL RESOURCES



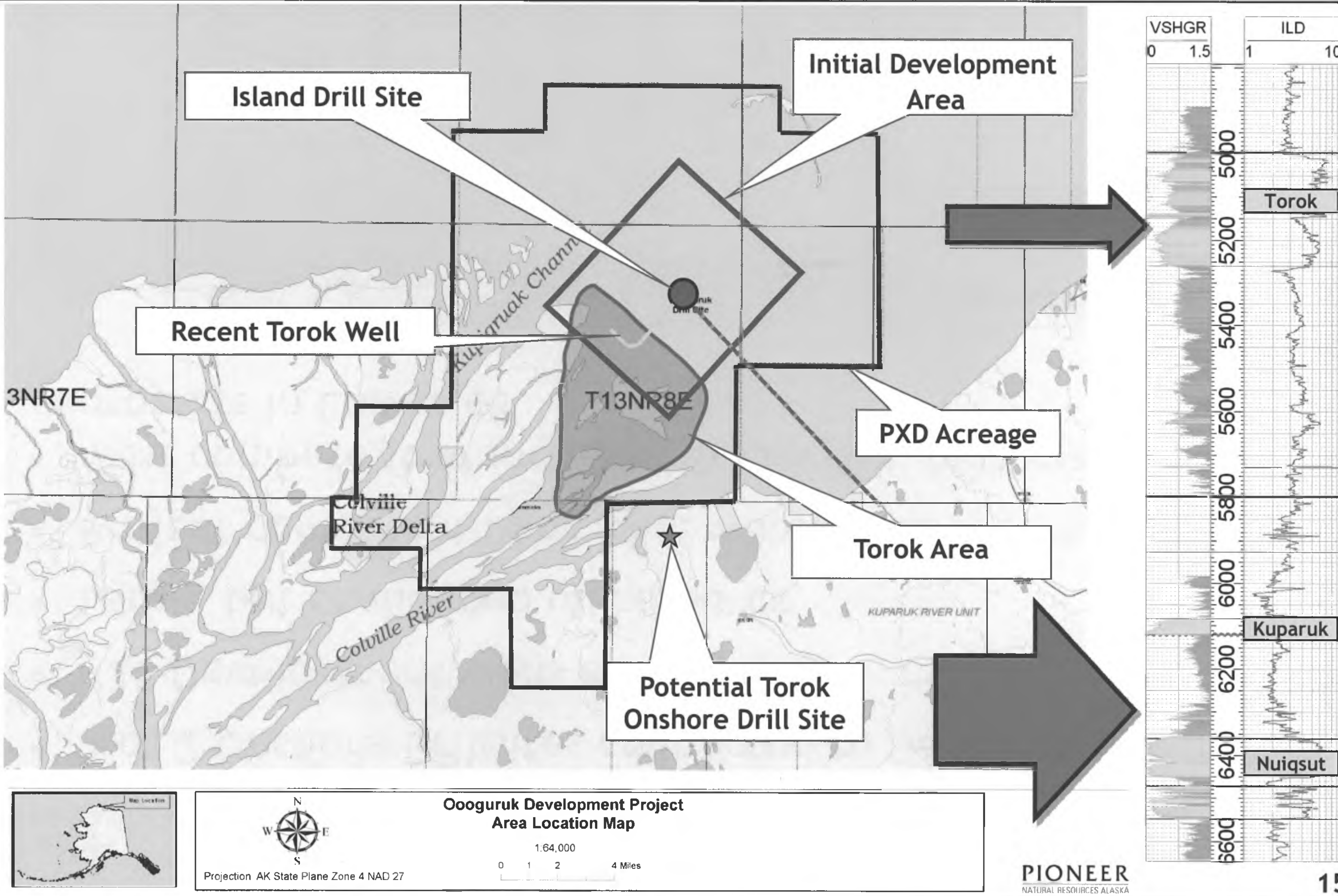
Alaska's Severance Tax

PIONEER
NATURAL RESOURCES

- **Pre 2007: ELF (Oooguruk Project Sanction)**
  - Low Rate Fields - No Severance Tax
- **2007: PPT (Oooguruk Construction)**
  - 20% Investment Tax Credit
  - 22.5% Net Profits Tax
  - No Progressivity
- **2008: ACES (Oooguruk First Production)**
  - 20% Investment Tax Credit
  - 25% Base Tax Rate
  - Aggressive Progressivity (not indexed)
  - Maximum Tax Rate 75%

What's Next? Oooguruk Expansion

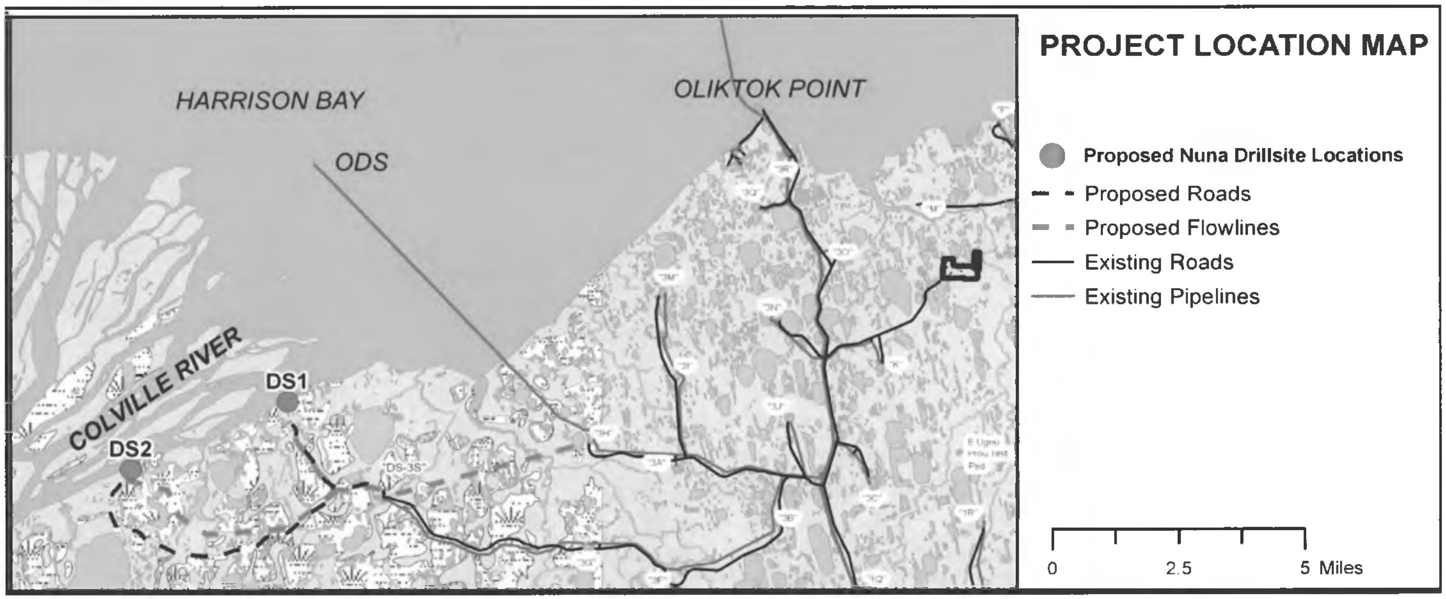
PIONEER
NATURAL RESOURCES



Expansion Project Scope

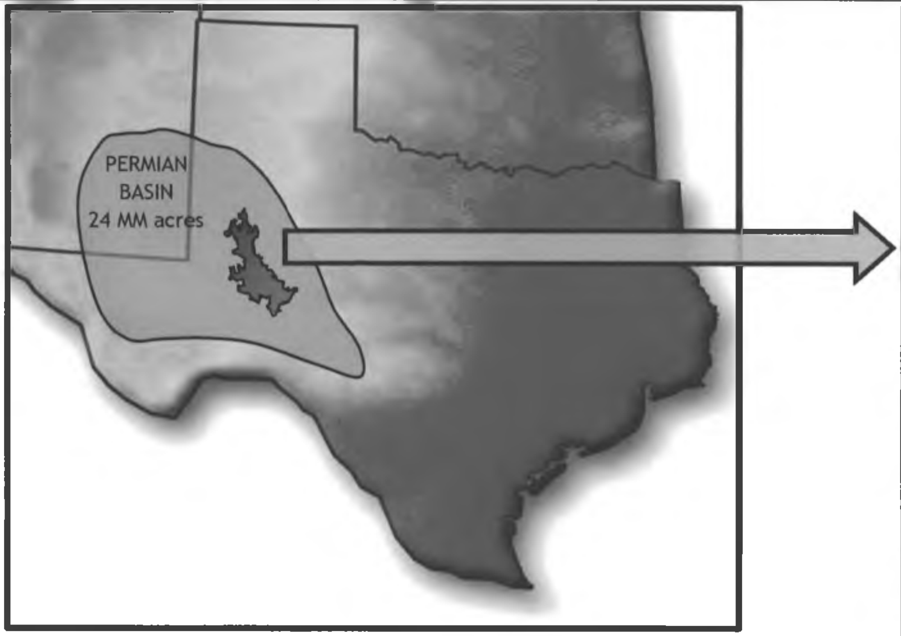
PIONEER
NATURAL RESOURCES

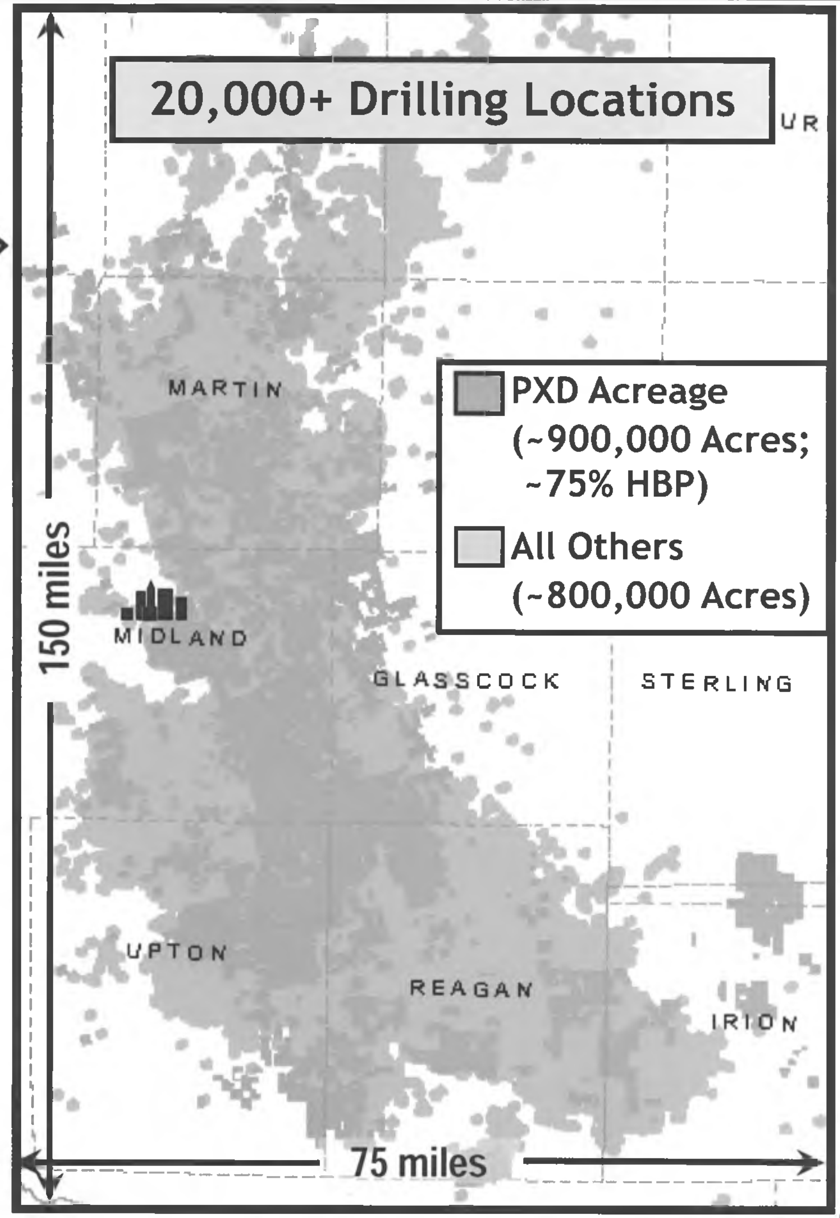
- 1 or 2 Onshore Drillsites connected to Oooguruk Tie-In Pad
- ~25 Development wells envisioned
- Large, but challenged oil resource
- Project contingent upon pilot waterflood success
- Must compete for funding with low risk, high margin projects in Lower 48



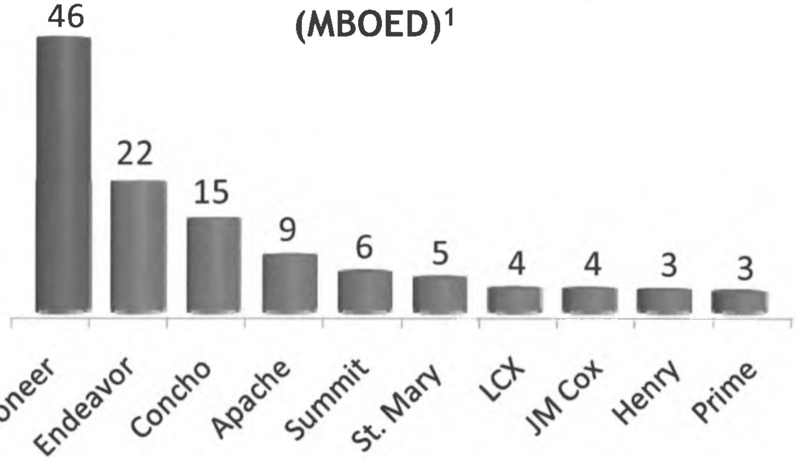
Competition - West Texas Spraberry Development

PIONEER
NATURAL RESOURCES





Spraberry Field Gross Production by Operator (MBOED)[1]



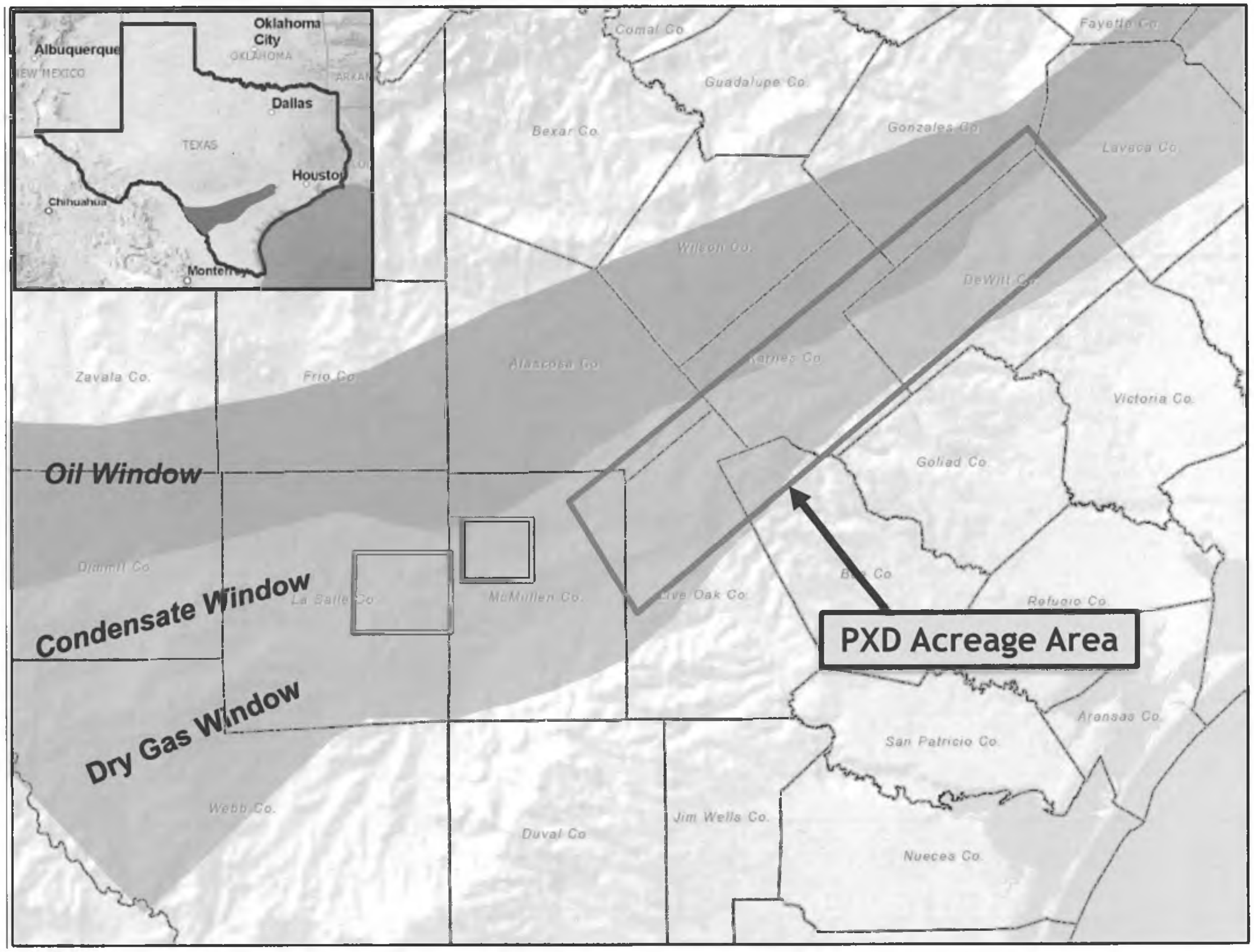
1) Based on 2009 data from Railroad Commission of Texas

Competition: Eagle Ford Shale Development

PIONEER
NATURAL RESOURCES

Map source: PXD

- Gross resource potential of play: ~150 TCF[1]
- >100 rigs currently running in the play



1) Source: Tudor, Pickering, Holt & Co.

Current Alaska Scorecard

PIONEER NATURAL RESOURCES

Alaska Relative to Lower 48 Resource Plays:

- Resource

Resource Report Card	Alaska	Lower 48
Resource Potential		✓
Resource Competition	✓	
Geologic Risk		✓
Oil Bias	✓	
Regulatory Process Ease		✓
Land Acquisition	✓	

- Profitability

Profitability Report Card	Alaska	Lower 48
Cycle Times / Payback		✓
Execution Risk		✓ ✓
Capital Cost		✓
Operating Margins		✓

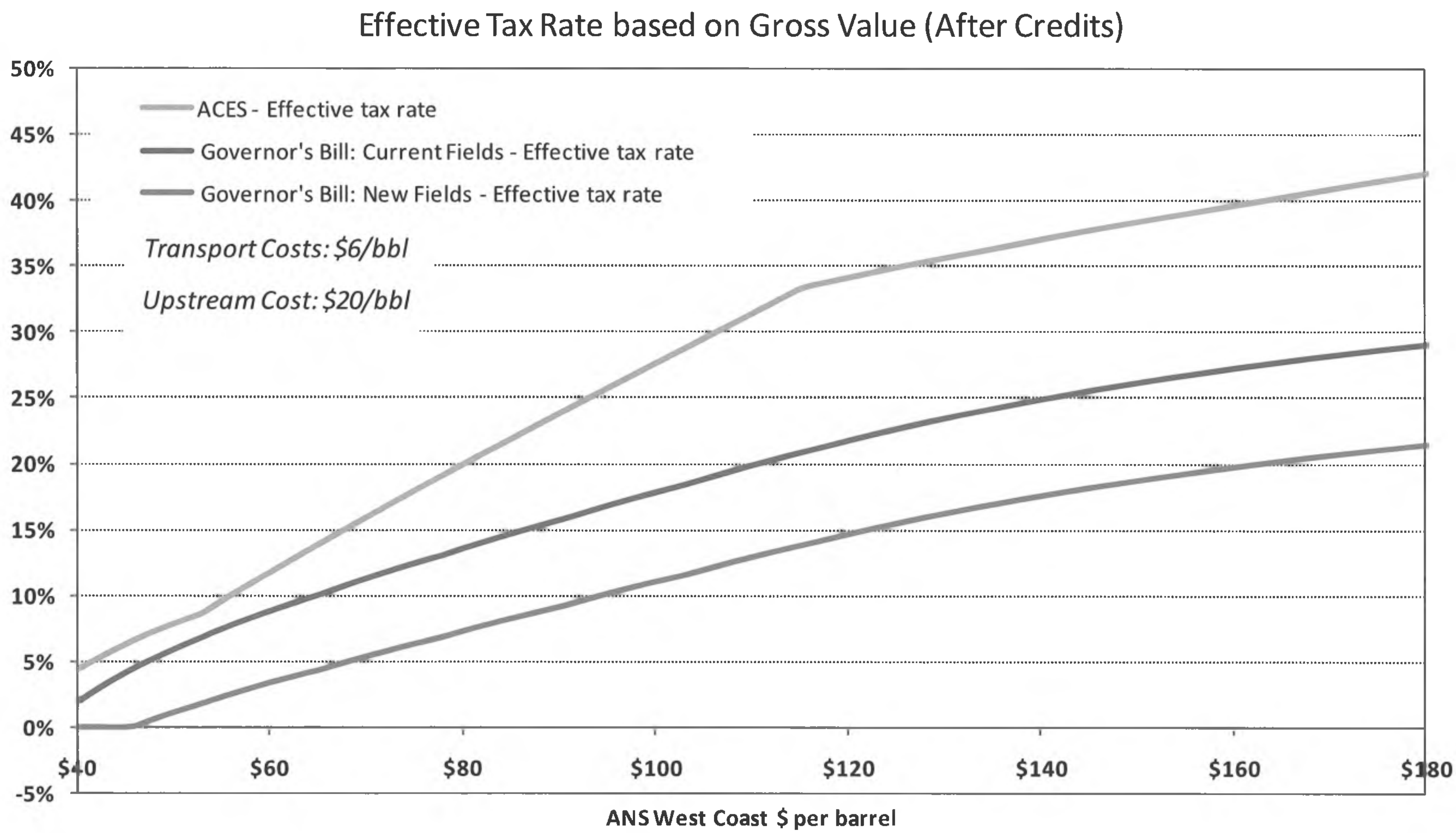
Closing Thoughts

PIONEER
NATURAL RESOURCES

- **Pioneer is evaluating an Oooguruk expansion that must compete with L48 resource plays with:**
  - Large resource potential in Pioneer's back yard
  - Short project cycle times and high margins
  - Very favorable fiscal terms
  - Much lower capital cost
- **Oooguruk Expansion**
  - New project - new barrels in TAPS
  - Create ~500 construction jobs
  - Create ~100 development jobs

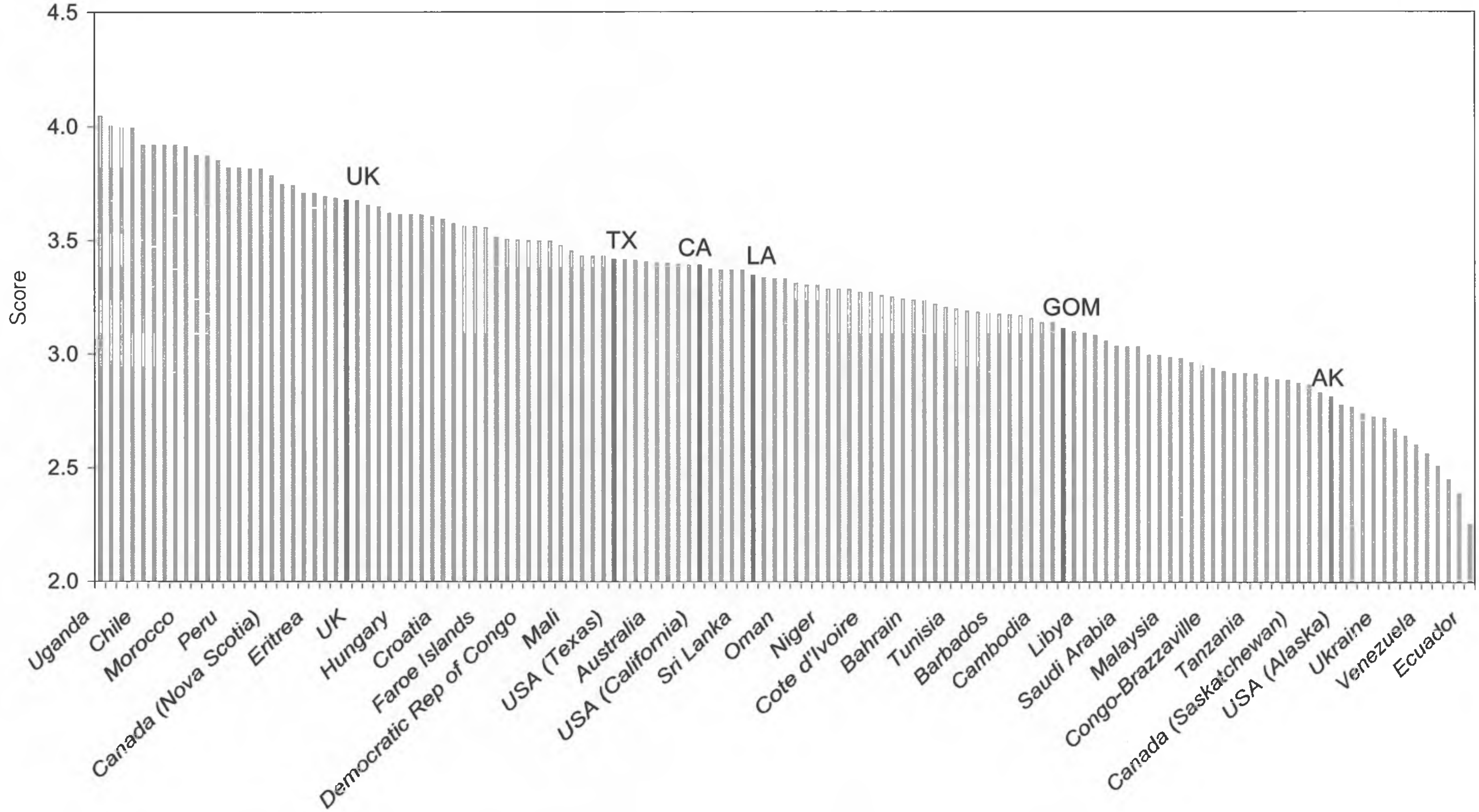
- **HB 110 will have a positive, material impact**
  - Increased investment credits for well related costs
  - Indexing of progressivity
  - Provide administrative certainty

Effective Tax Rates on Gross Current law and HB 110



House Resource Committee
BP Alaska Testimony- Claire Fitzpatrick, CFO
February 16, 2011

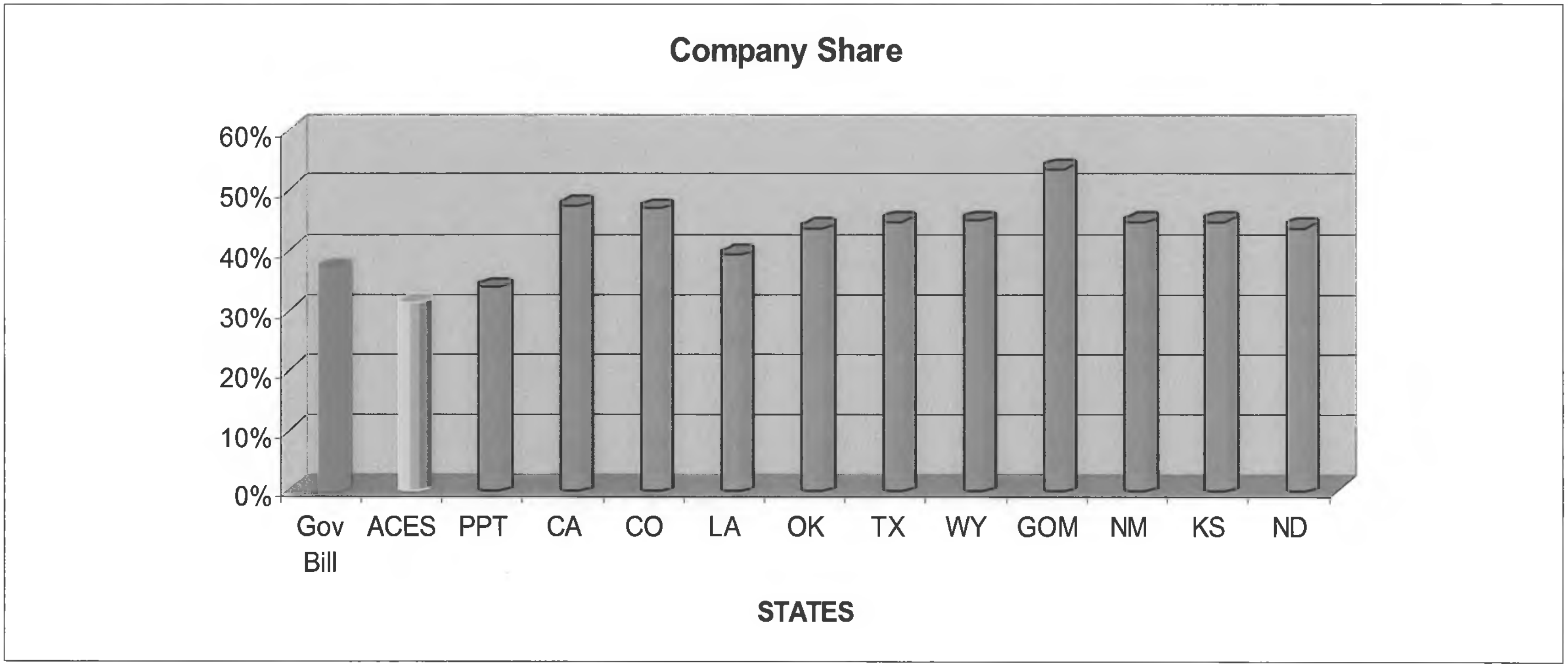
Alaska is uncompetitive



Alaska's fiscal terms rank 117 out of 129 when compared to other regions

Source: Wood Mackenzie Petroleum Fiscal index Report 2010

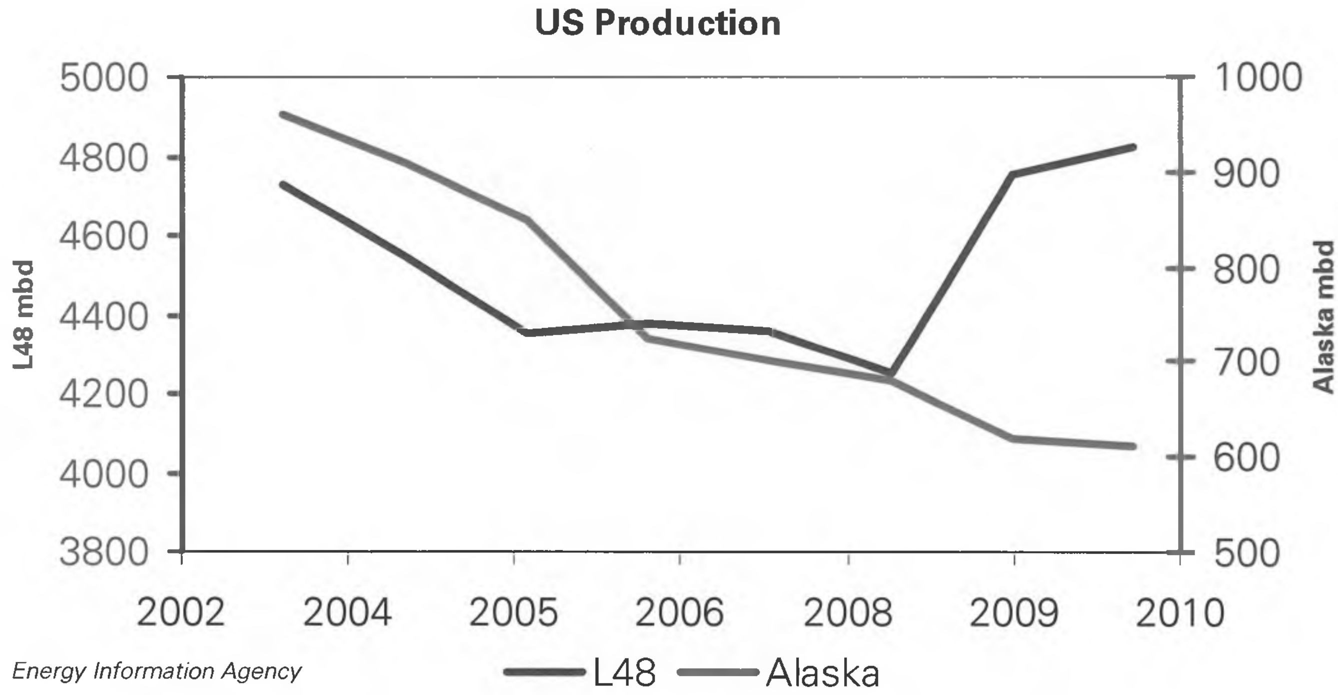
Alaska returns are uncompetitive



Source: BP Tax Department

- Companies make less in Alaska than elsewhere in the US.
- Its harder for Alaska to attract investment.

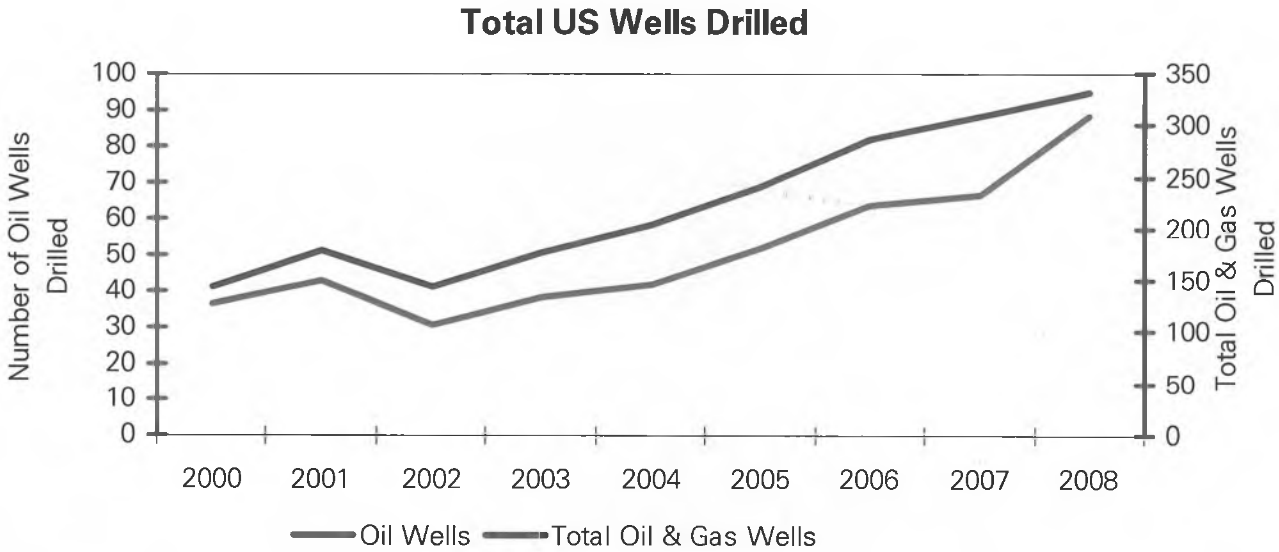
US production is growing; Alaska production isn't



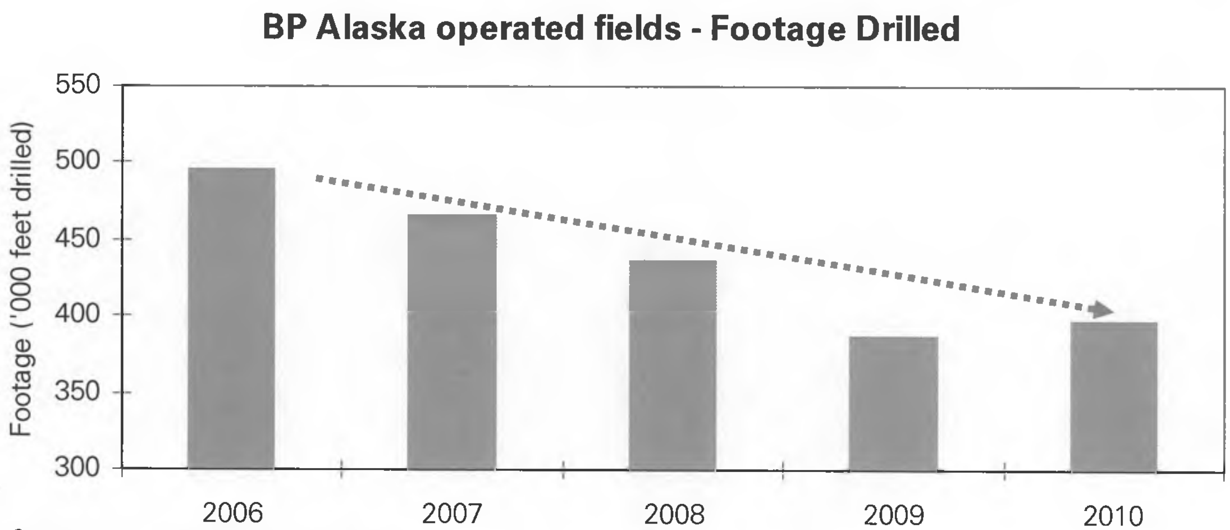
Source: Energy Information Agency

- Production in the Lower 48 has been increasing.
- Alaska production is in steady decline

Lower 48 activity is increasing; Alaska activity isn't



Source: Energy Information Agency

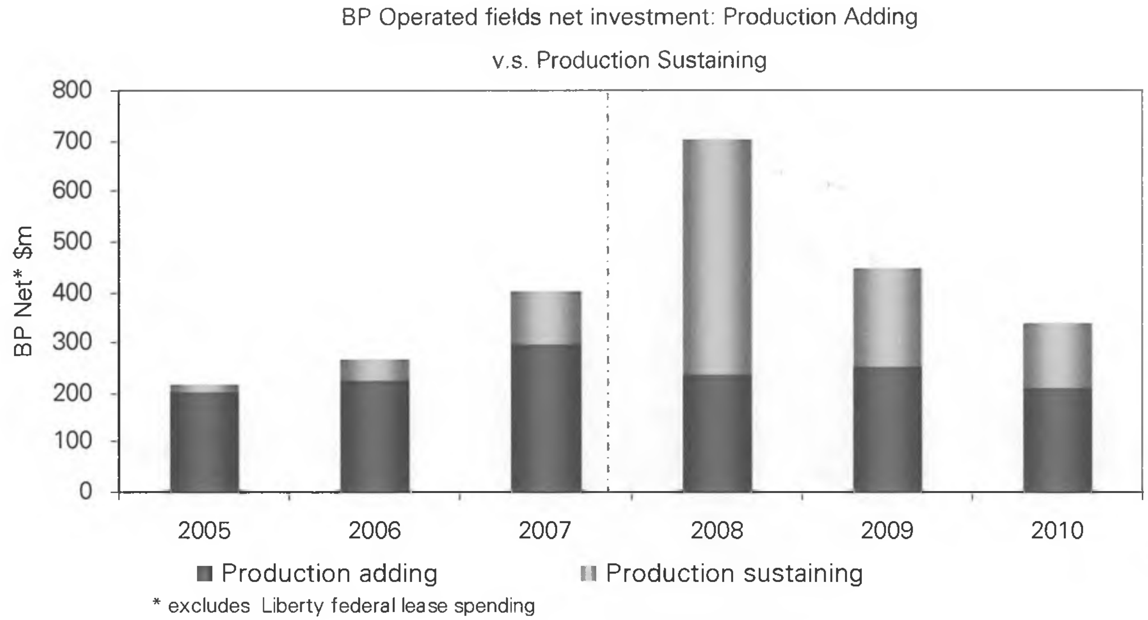


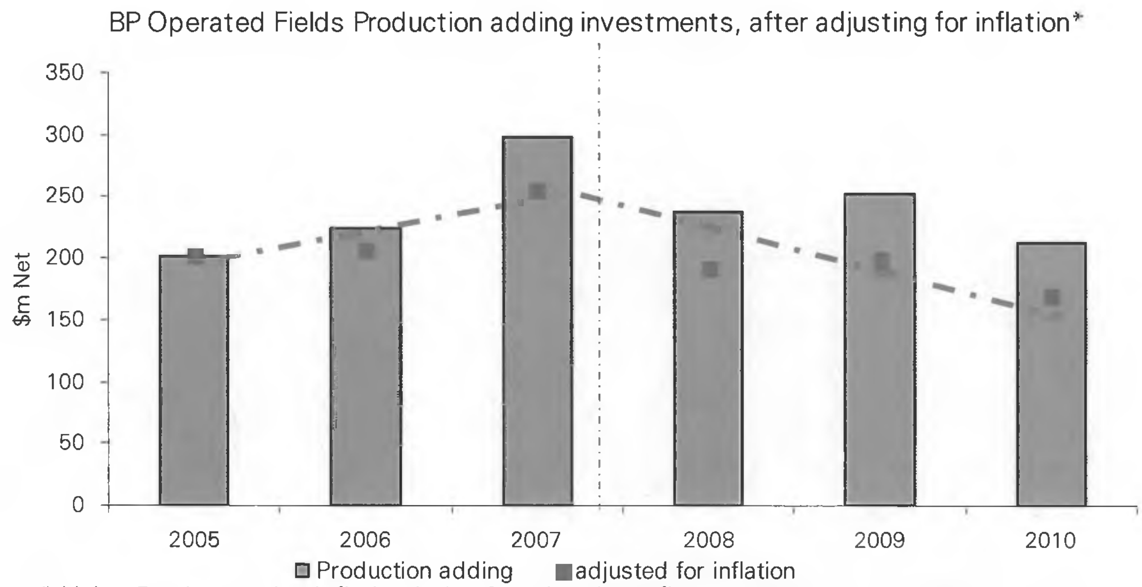
Source: BP Alaska Internal Records

- Looking at footage Drilled, the Oil and Gas activity in the Lower 48 has been increasing over last few years.

- Footage Drilled by BP in its operated fields has been on a steady decline.

Less money being spent on new oil since ACES





* Using Producer price inflation index for oil and gas field machinery and equipment index

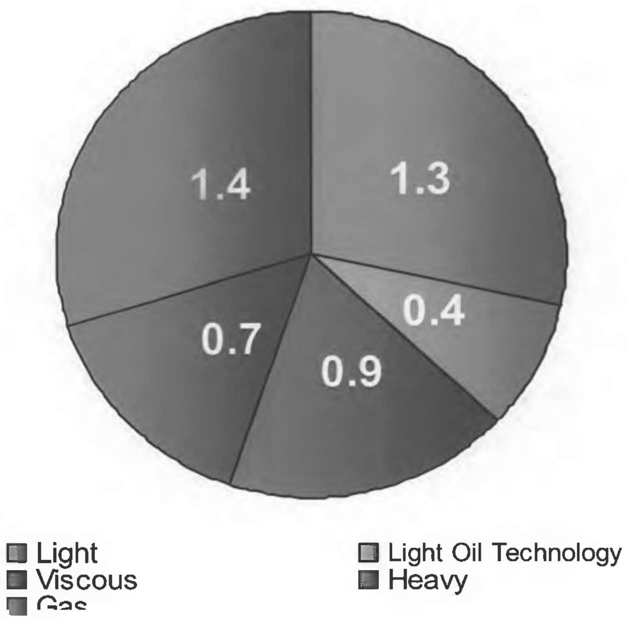
- Overall investments by BP Alaska have remained high
- Production adding activity spend has been flat to decreasing

Source: BP Alaska Data and US Department of Labor

Taxes have made Alaska uncompetitive in BP's portfolio

Resource Potential for Growth

4.7 Bboe



- What locations are attracting investment?

- BP list of 15 sanctioned large investment projects ($20bn net spend)
  - GOM (6)
  - Egypt (1)
  - North Sea (4)
  - Azerbaijan (1)
  - Canada (1)
  - North Africa (1)
  - Angola (1)
  - TNK BP (3)

- BP Alaska – no large projects

Governor's Bill (HB 110) – Necessary step in the right direction

- BP strongly supports this bill
  - Improves competitiveness and encourages investment

- What we like
  - Bracket structure for progressivity
    - ✓ Incentivizes investment
    - ✓ Rebalances risk reward
  - Additional credits for drilling investments
    - ✓ Incentivizes production adding investments
  - Reduction in statute of limitations and punitive interest rate
    - ✓ Increases certainty, removes unfair provision
  - Annual calculation of production tax rather than monthly
    - ✓ Matches costs with revenues and increases predictability

Increased investment = Alaskan jobs and production

- BP will re-evaluate the entire inventory of opportunities
  - Note: BP owns 26% of Prudhoe Bay - investments require other working interest owner approvals

- Opportunities that could become competitive if bill is passed:
  - Increased drilling, potentially adding another Rig in service
  - Increased wellwork
  - Gas Partial Processing /I - PAD
  - Evaluate 'at scale' development viscous opportunities
  - Increased R&D spending to develop heavy oil

- The sooner the bill takes affect, the sooner increased activity can happen

House Resources
HB110

ConocoPhillips Alaska
Wendy King – VP, External Affairs

February 16, 2011

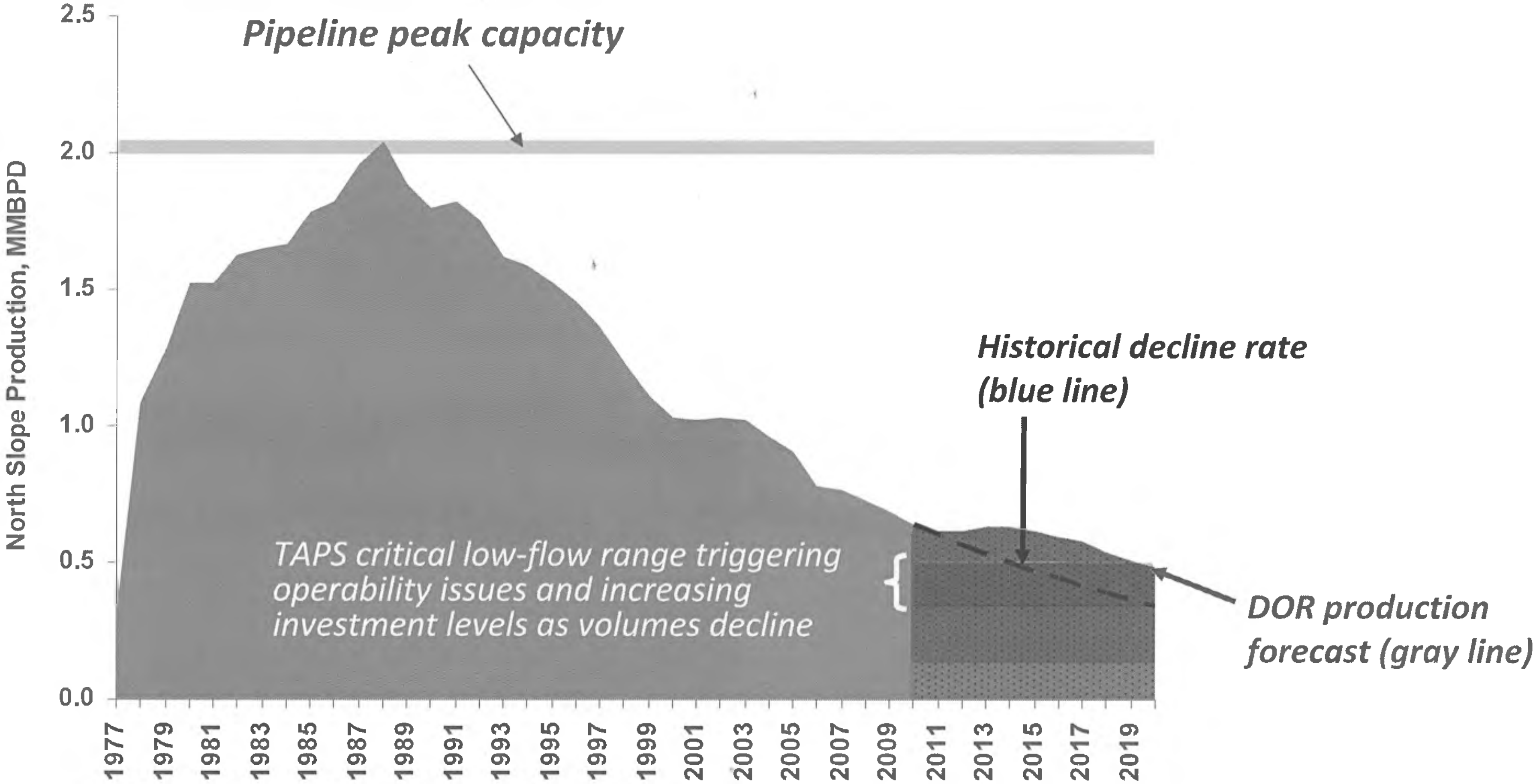
Impact of HB 110

Governor's Objectives | **ConocoPhillips' View**

- Be More Competitive
- Create More jobs for Alaskans
- Increase Production

Source: DOR Presentation to House Resources, February 11, 2011

TAPS Future Relies on New Production

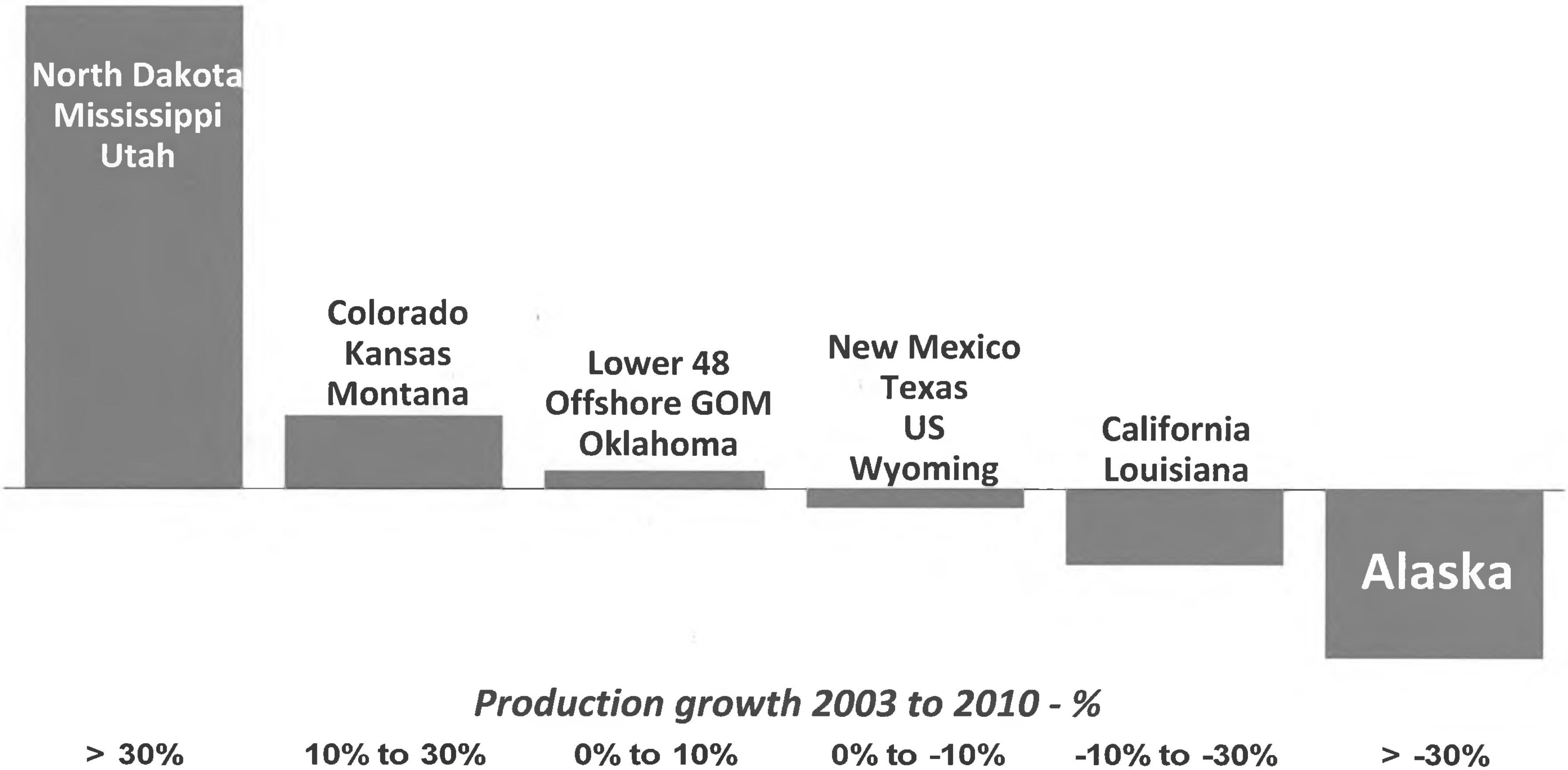


Stimulating production investment key to TAPS future

Source: Alaska Department of Natural Resources Annual Report
TAPS low flow impact study presentation – March 9, 2010

ConocoPhillips

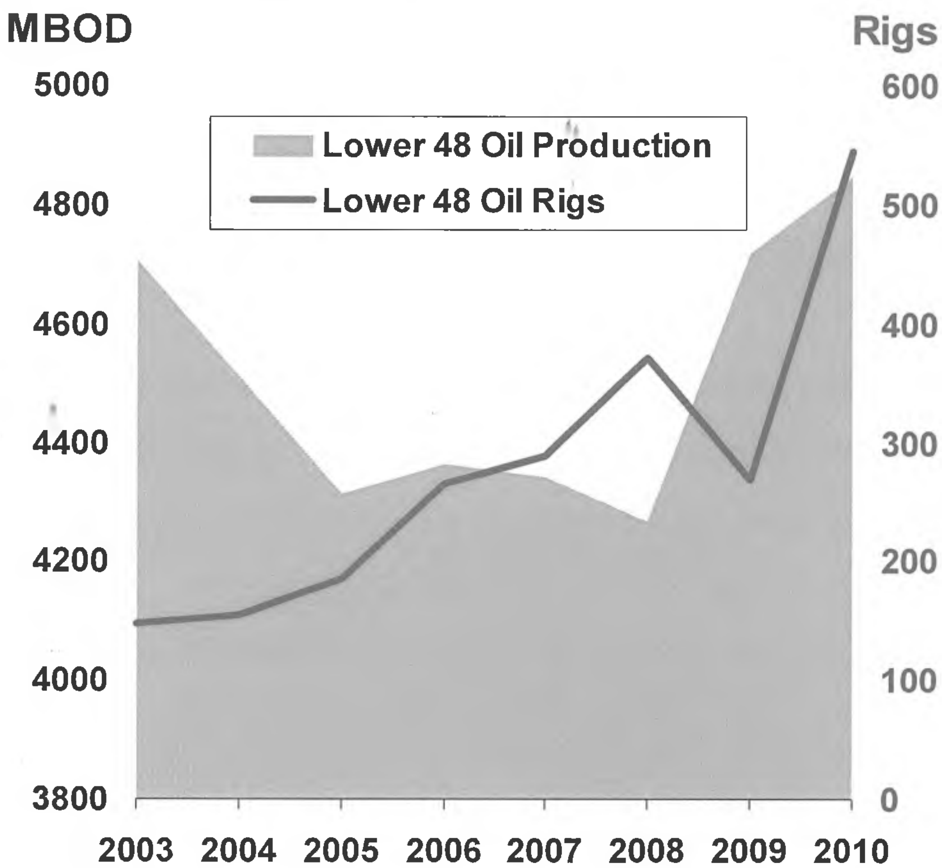
U.S. Production Changes Since 2003

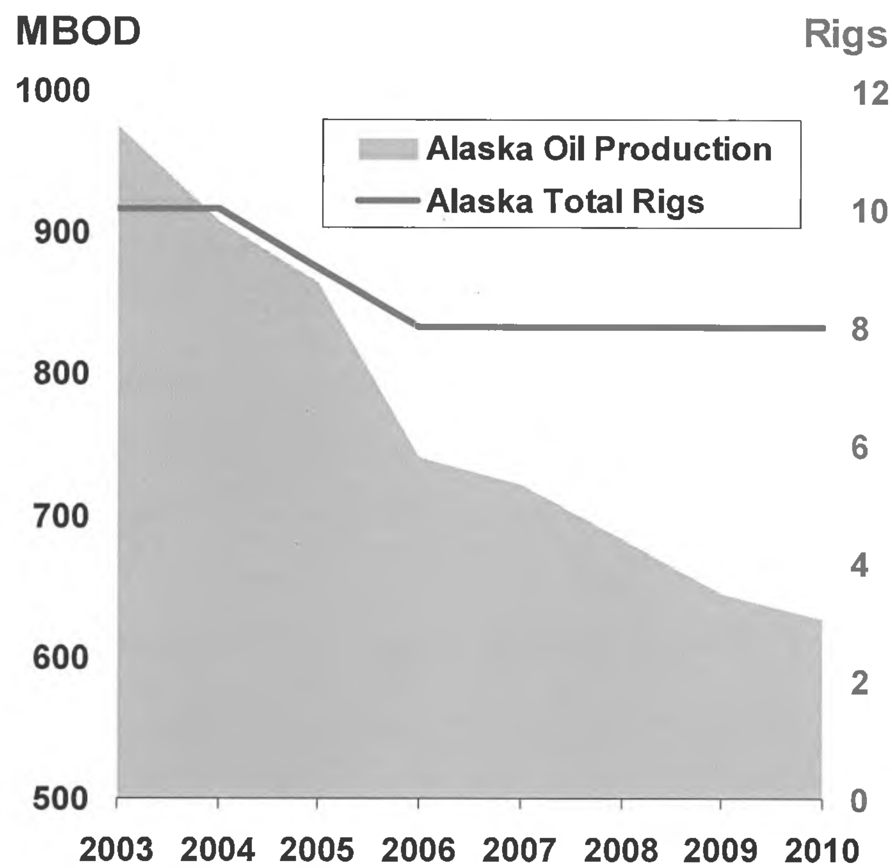


Alaska lags other states despite high prices

Source: Energy Information Administration
Regions with minimum 50,000 bopd production

Rising L48 Rig Count Stems Oil Decline



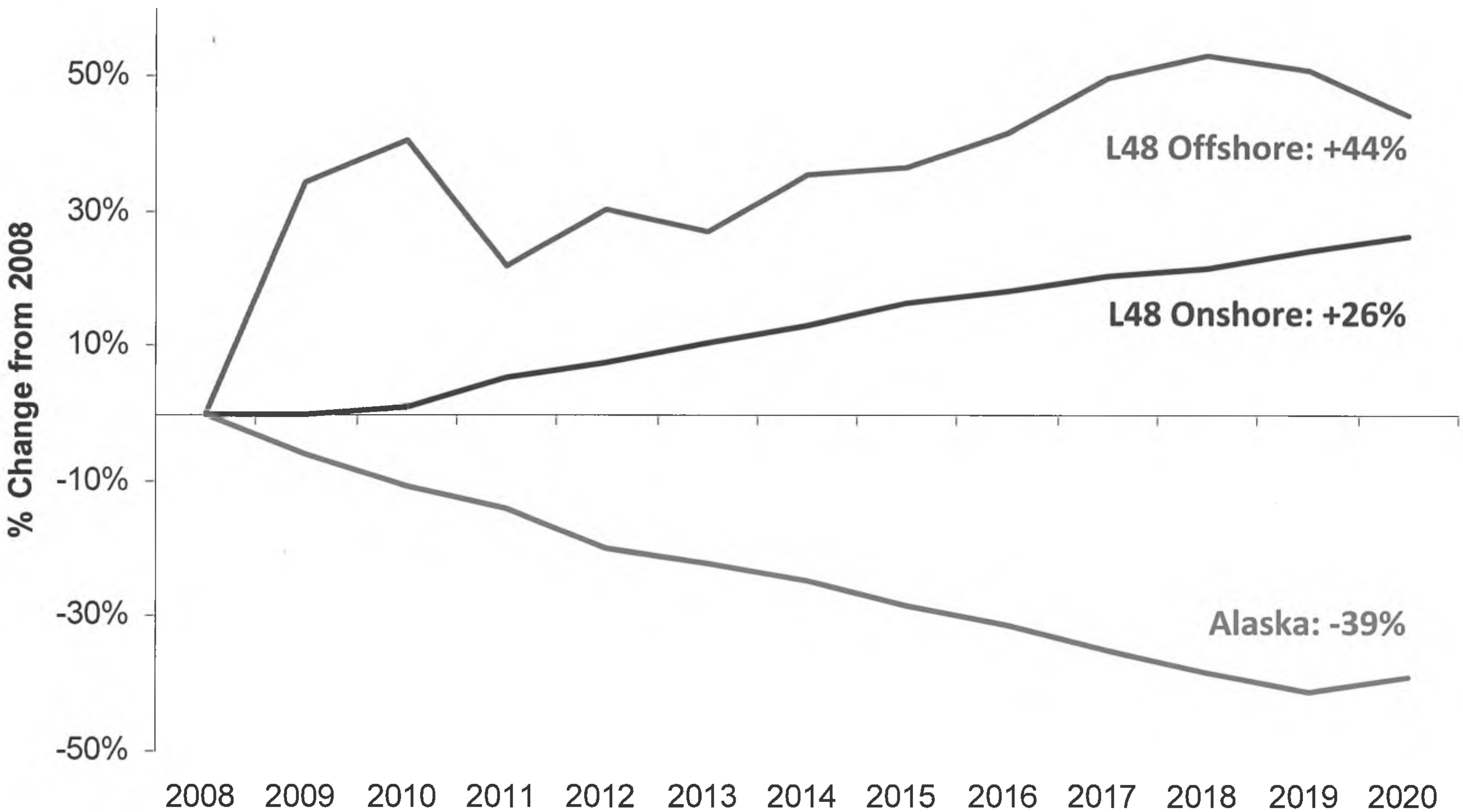


Increased production follows increased drilling

Source: Energy Information Administration & Baker Hughes

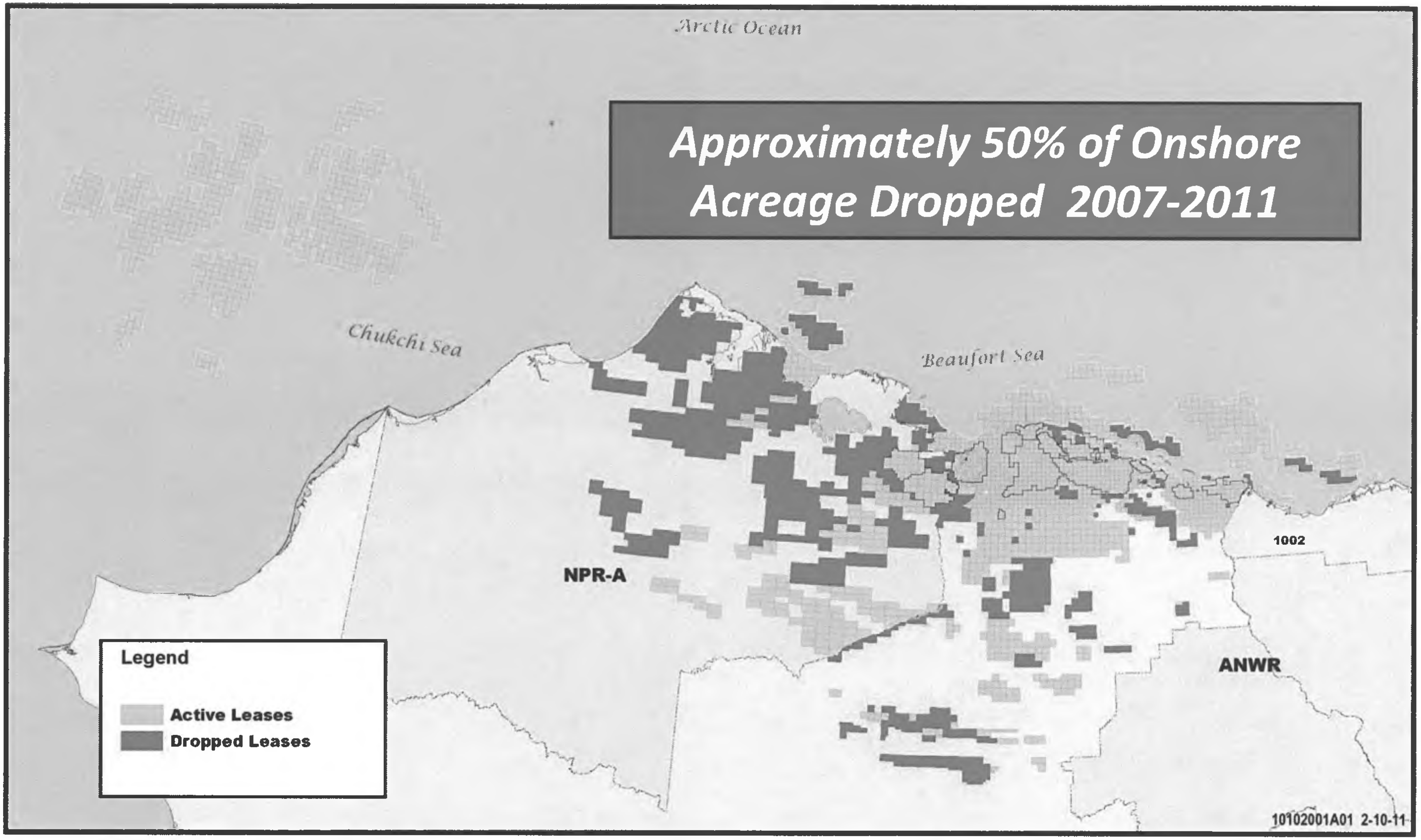
ConocoPhillips

United States Oil Production Forecast



Source: Energy Information Administration, AEO2011 Reference Case

Alaska Industry Acreage Reduction

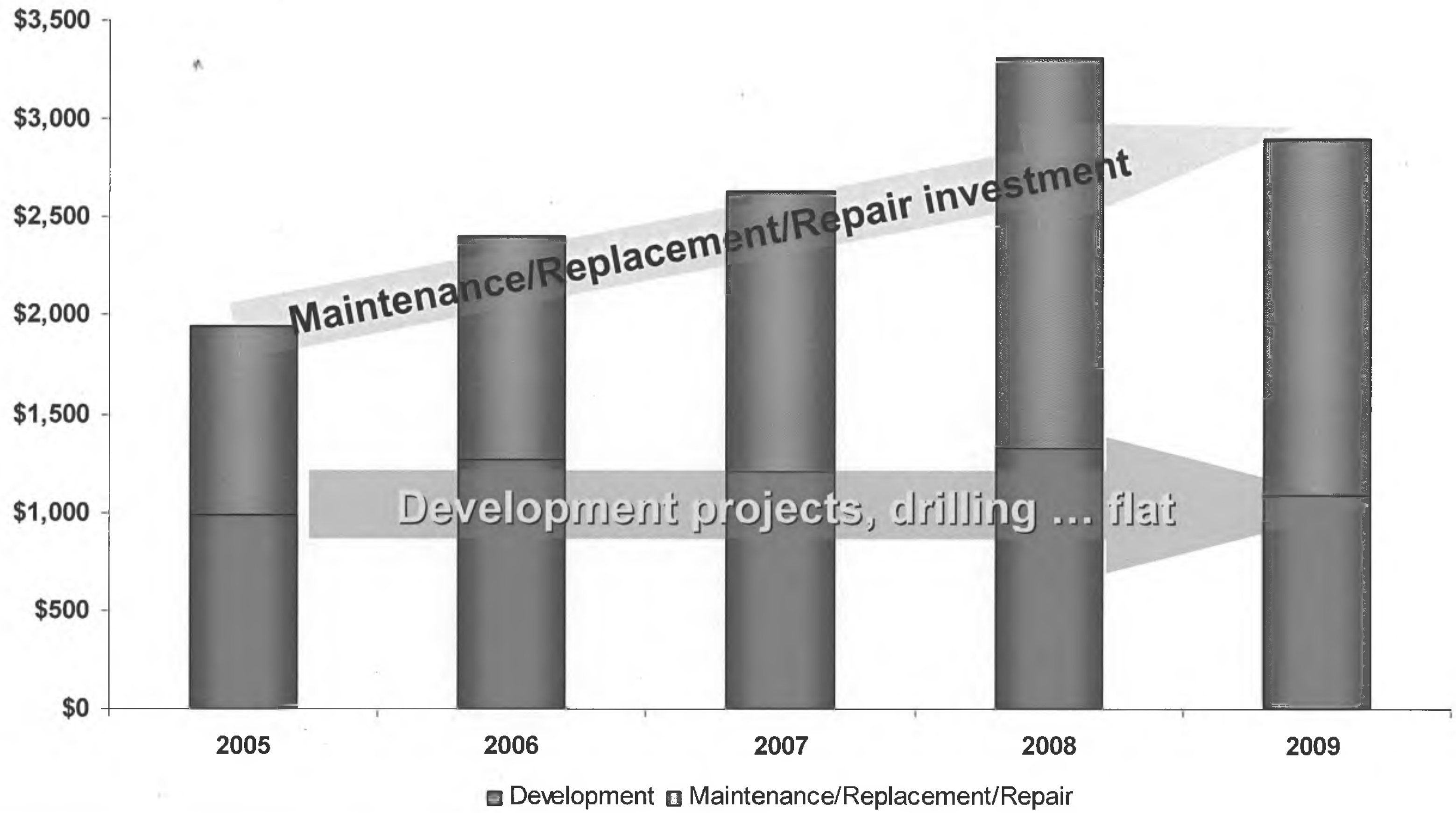


Source: COP analysis of publicly available data

ConocoPhillips

Core Field Investments Extend Field Life

Prudhoe, Kuparuk, Alpine (Core fields) gross investments include capital/operating expense, $MM



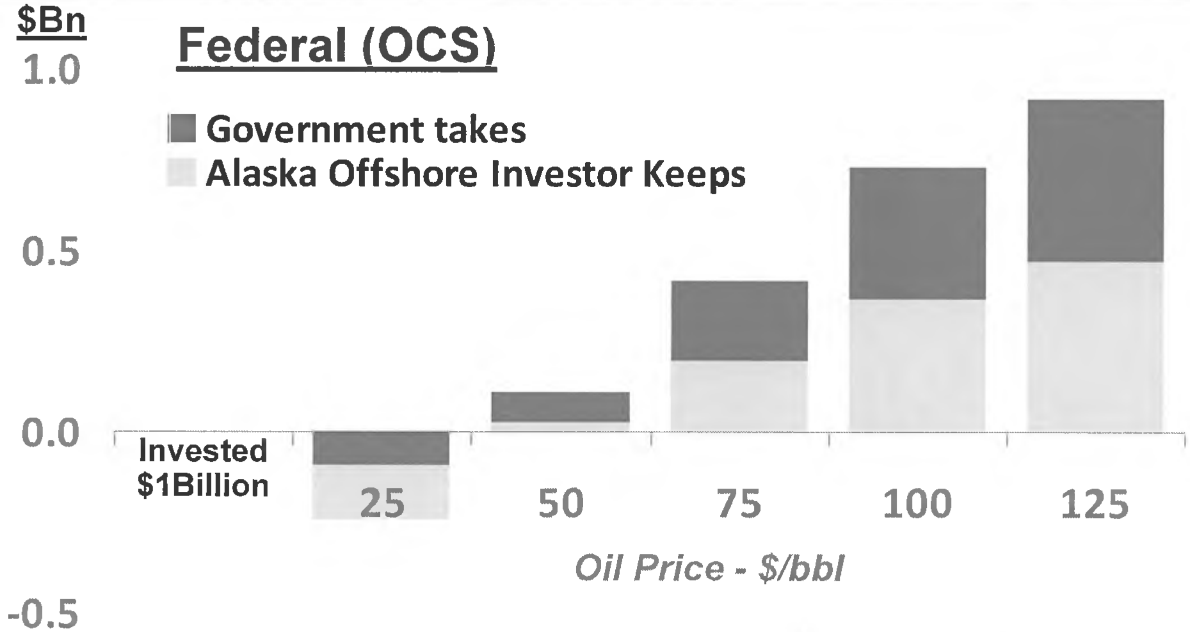
Maintenance investment essential to extending field life

Source: ConocoPhillips internal

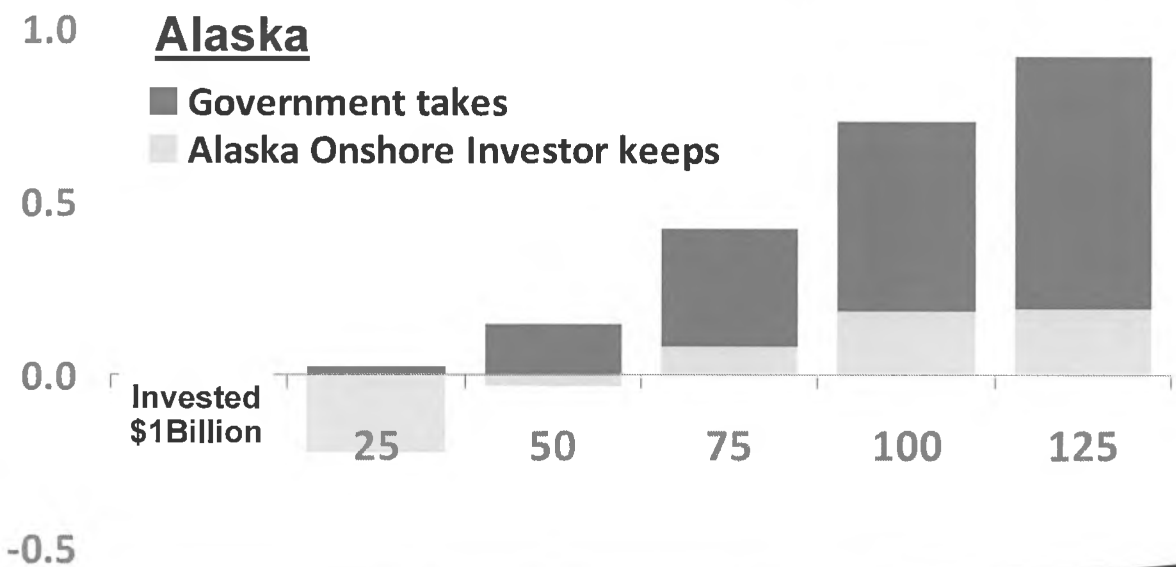
ConocoPhillips

Impact of Progressivity

Example – $1Billion capital investment



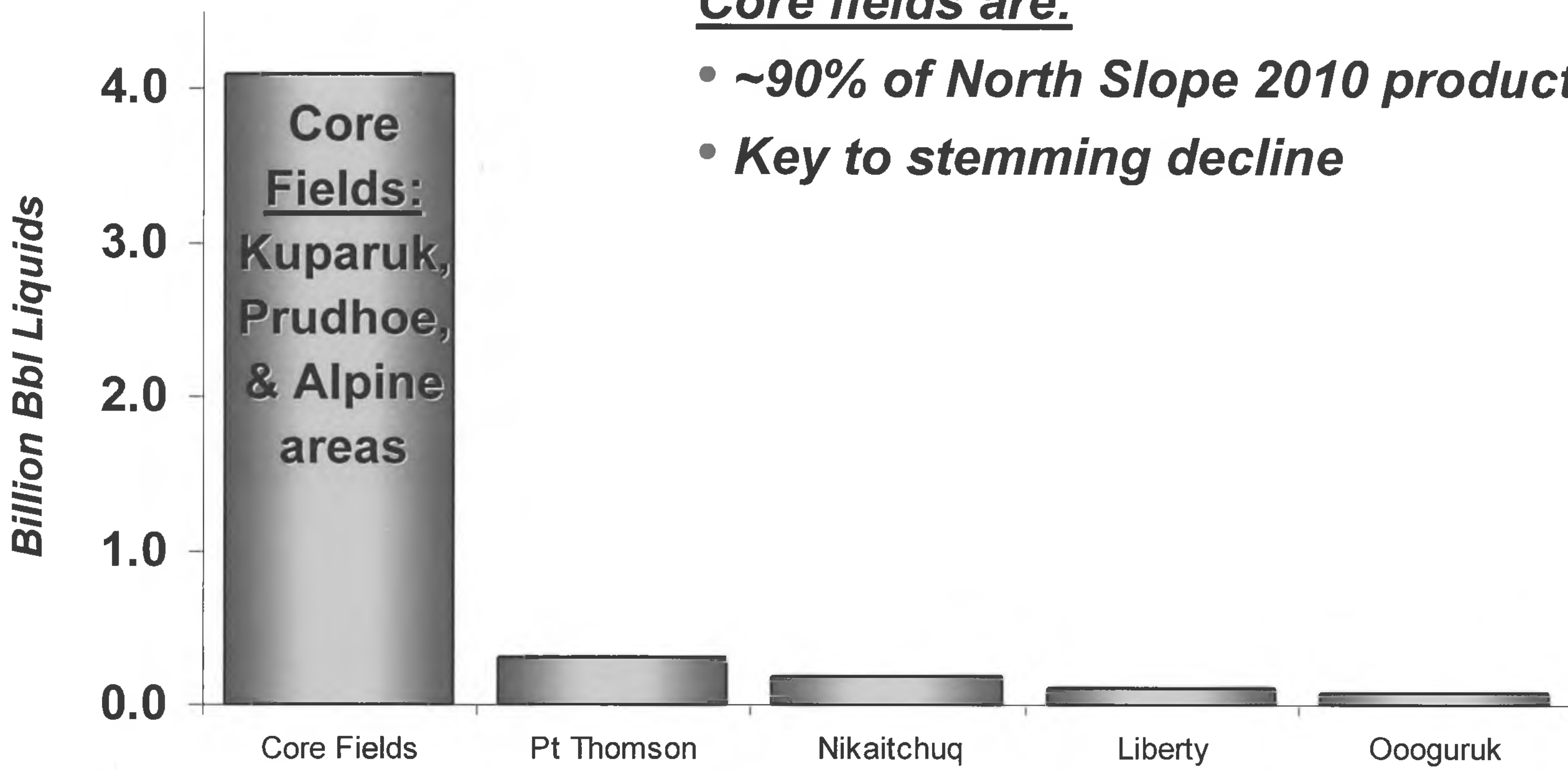
- Adequate returns in success case justify up front investment risk



- Alaska onshore fiscal terms: Risk / reward is out of balance

Discounted cash flow

North Slope Remaining Barrels



Core fields are:

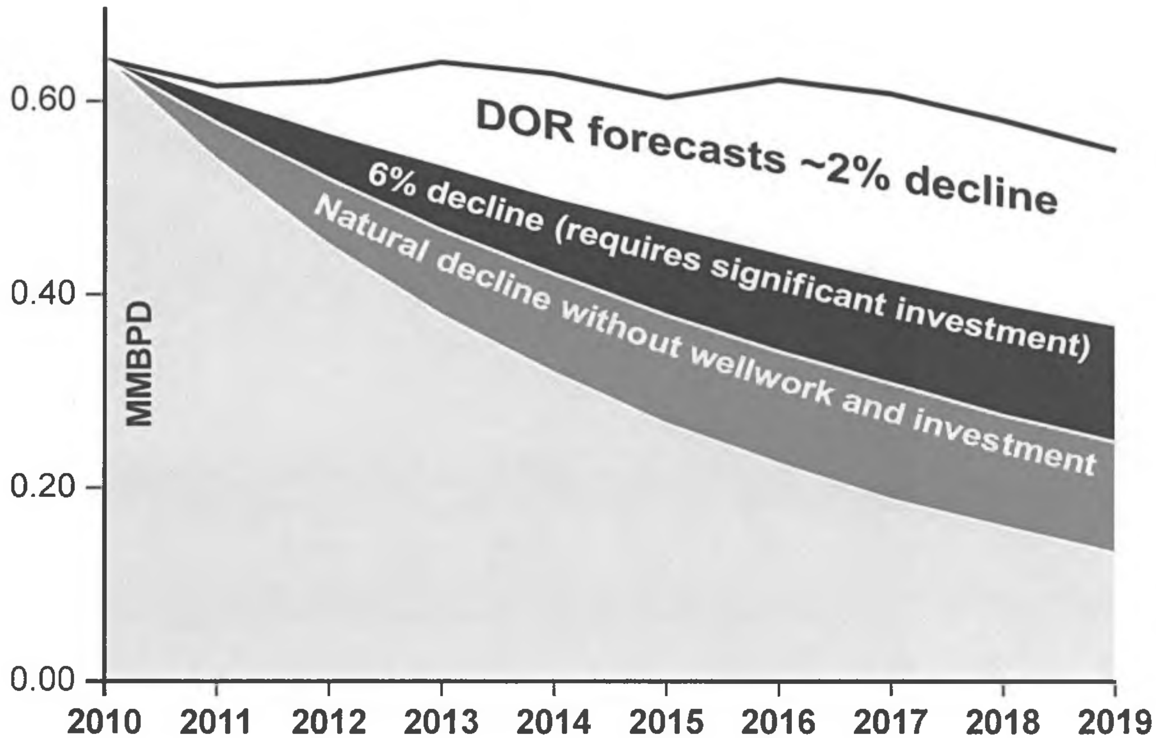
- ***~90% of North Slope 2010 production***
- ***Key to stemming decline***

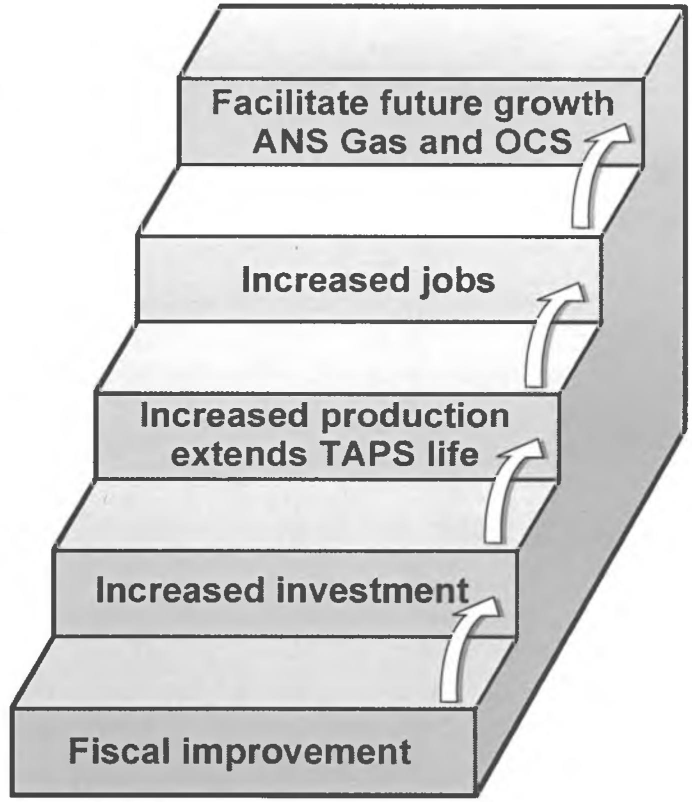
Core fields are dominant source of state production

Source: DOR 2009 production forecast 2010 – 2050 volumes

ConocoPhillips

Alaska's "Bridge" to Growth Projects





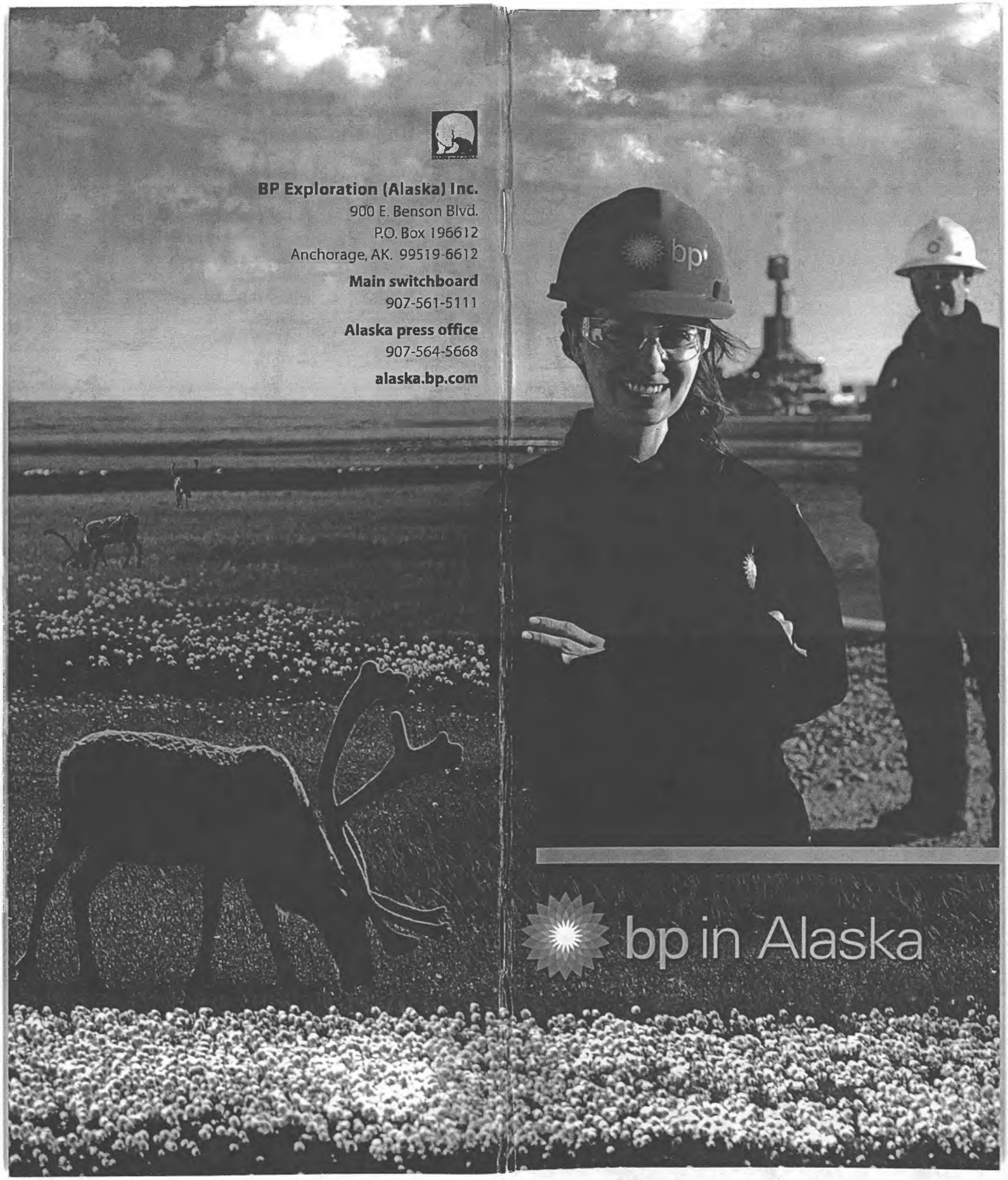
Future production dependent upon investment

Sources: DOR North Slope production forecast and extrapolation of DOR expenditures forecast
ConocoPhillips estimates for base decline rate

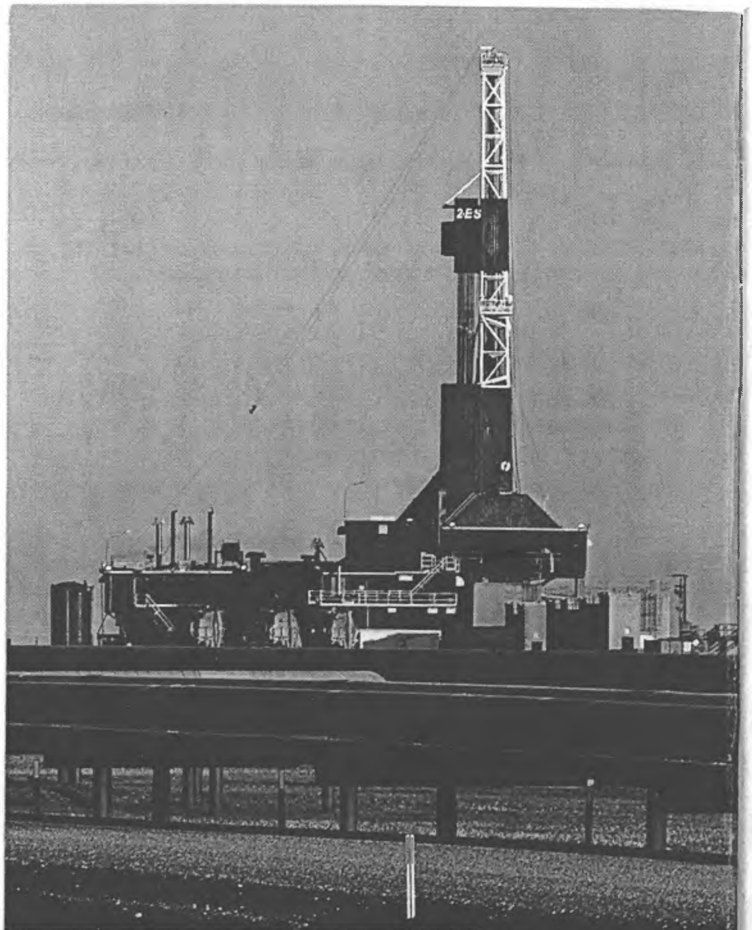
ConocoPhillips Supports HB110

- **Existing Units**
  - Bracketing Progressivity is critical component
  - Moves Alaska toward a more balanced risk/reward environment
  - Incentivizes investment in core fields and existing units
  - Supports longer term projects / longer term investment
- **Improved Well Credits**
  - Incentivizes well related activity
  - Increased drilling/workovers provide additional short-term jobs
  - Support language being clarified to include workovers
- **Administrative Improvements**
  - Audit period to 4 years – provides improved tax payment predictability
  - Interest – eliminates punitive rate for good faith tax filings
  - Monthly vs. annual progressivity – improves alignment on cost and revenue calculations
- **Effective Date**
  - COP believes effective dates should be accelerated by 1 year

HB110 Improves Alaska Investment Climate



BP Exploration (Alaska) Inc.
900 E. Benson Blvd.
P.O. Box 196612
Anchorage, AK. 99519-6612
Main switchboard
907-561-5111
Alaska press office
907-564-5668
alaska.bp.com
bp
bp in Alaska



CONTENTS

ABOUT US

BP opened its first office in Alaska in 1959 and today operates 15 North Slope oil fields and four North Slope pipelines. It also owns a significant interest in six other producing fields and in the Trans Alaska Pipeline System (TAPS). BP Exploration Alaska is an upstream strategic performance unit of the BP Group. Globally BP ranks among the 10 largest oil companies and is the fourth largest corporation. The Alaska business is a key part of BP, and the second largest resource base for BP worldwide. Alaska North Slope gas represents the largest known, undeveloped gas resource in BP's global portfolio.

2008 Statistics

Employees

2,000
(81% Alaska residents)

Capital investment

Net capex: $1.1 billion

Operating budget

$1.3 billion

Net production rate

204,300 barrels of oil equivalent per day

Gross production rate for all BP operated fields

471,000 barrels of oil equivalent per day

North Slope wells spudded

91 wells (72 BP operated)

Taxes and royalties

$3,981 billion total payments

Community investment

$10 million+

This publication of "BP in Alaska" fact book printed July 2009. All 2008 statistical data is based on full calendar year, unless otherwise noted.

For more information go to
http://alaska.bp.com

President's Message

John Mingé

The same year Alaska became the 49th state, BP opened its first Alaska office, marking the beginning of a long, successful relationship. Over the years, Alaska and BP have shared a pioneering spirit. The challenges we face today may be different from 50 years ago, but at BP we are still focused on a productive future.

Even in today's difficult economy, BP has a long-term strategy in Alaska. The elements of our plans include: using new technologies to explore for Alaska's immense known resources; renewing North Slope infrastructure; reinforcing our commitment to safe and sustainable operations; and commercializing the Alaska natural gas resource.

Ultimately, a large part of planning for tomorrow also includes training Alaskans to fill jobs not just today, but long into the future. BP supports Alaska hire and training programs through the University of Alaska and actively recruits interns and graduates from the Alaska Native Science and Engineering Program (ANSEP) and the Alaska Process Industries Careers Consortium (APICC).

The success of technically challenging projects like heavy oil development, the Liberty ultra-extended reach wells, and Denali - The Alaska Gas Pipeline will provide more opportunities for future generations of Alaskans.

Our objective is to build on the accomplishments of BP in Alaska and deliver a long-term, sustainable business here. This BP in Alaska brochure provides an overview of our plans, operations and production.

Sincerely,

John Mingé
President
BP Exploration (Alaska) Inc.

1959 BP opens Alaska office and acquires federal leases.

1964 BP acquires its first tracts in Prudhoe Bay area in state lease sales.

1969 BP confirms 1968 Prudhoe Bay field discovery with Put River No. 1 well.

COMMUNITY SUPPORT

BP is one of the largest private sector investors in Alaska, and our investments extend beyond our business to the communities where we operate and where our employees and their families live.

In 2008, BP contributed more than $10 million to support more than 200 nonprofit and educational organizations and programs in Alaska. BP also supports many education and workforce development programs, and provides 25 four-year scholarships annually to graduating Alaska high school seniors. In addition, BP has recognized more than 450 outstanding educators through the Teachers of Excellence program.

BP's Alaska employees also support more than 700 community and education organizations in 40 Alaska communities though the BP Fabric of America program. Under the program BP's employees are able to designate a $500 contribution from BP America to the charity of their choice.

In addition employees support 150 youth team programs across the state. In 2008, BP Alaska employees contributed more than $500,000 to United Way and other community and education organizations. They also contributed thousands of volunteer hours. The company matches employee donations, volunteer hours and fund raising efforts.

BP employees supported more than 700 community and education programs in 40 Alaska communities.

1969 BP Alaska begins Prudhoe Bay field development.

1970 BP enters agreement with Sohio and transfers its Prudhoe Bay leases in exchange for equity interest in Sohio.

BP's innovative Energy Center opened in 2002.

BP ENERGY CENTER

The BP Energy Center was built to support the community. This facility is a training, meeting and conference center and is available without charge to nonprofits and education organizations from throughout Alaska. Since opening in 2002, more than 100,000 visitors have passed through the center.

BP has recognized more than 450 Alaska educators through the BP Teachers of Excellence program. Christine Villano teaches first grade at Denali Elementary School and was the 2008 BP Teacher of the Year in Fairbanks.

1973 Congress approves the Trans Alaska Pipeline Authorization Act.

1974 Trans Alaska Pipeline construction begins.

EXPLORING THROUGH TECHNOLOGY

Today...

BP changed its focus several years ago from wildcat exploration to concentrate on exploring new ways to develop the vast North Slope resources that have already been discovered, but are not yet fully developed. It's been a good decision and we've had success adding production from heavy oil and smaller, technically challenging fields. BP is exploring technologies to unlock more barrels on Alaska's North Slope. These technologies include innovative drilling techniques, using carbon dioxide, low salinity flooding, and even bacteria. Alaska's North Slope has an extreme and challenging environment, from its unique and sensitive habitats to the Arctic weather. Yet it is also a place of incredible opportunities.

Tomorrow...

HEAVY OIL DEVELOPMENT

BP is testing new heavy oil development technology at Milne Point on the North Slope. The challenges are huge. This oil is cold, thick and sticky, and currently the most significant heavy oil is uneconomic to produce. Yet, we know that heavy oil development will be important to sustaining Alaska's oil production far into the future.

BP's heavy oil production test at Milne Point in the summer of 2008 was successful, and plans call for more wells as the project continues. BP conservatively estimates that 2 billion barrels of heavy oil may be technically recoverable using existing cold and thermal technologies, from the Schrader Bluff/West Sak and Ugnu reservoirs. The successful well used CHOPS (cold heavy oil production with sand) technology for the first time in Alaska.

With this success, BP is moving into the next phase of the project. The company plans to build and install a permanent technology test facility, fabricating truckable modules that will be shipped to Milne Point.

In 2008, heavy (viscous) oil production on the North Slope was about 46,000 barrels per day gross. BP's net production was 20,000 barrels per day. This production came from the Kuparuk satellite fields of West Sak and Tabasco; the Prudhoe satellite fields of Polaris and Orion; and the Milne Point Schrader Bluff field.

1977 Prudhoe Bay field begins production.

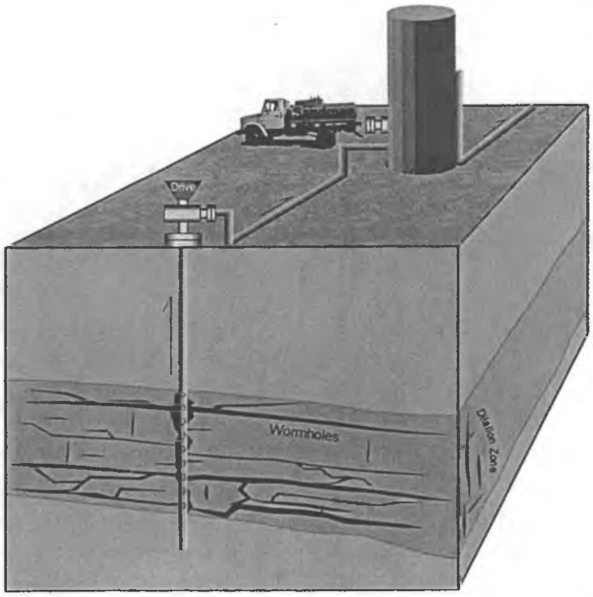
1981 Kuparuk field begins production.

1986 Lisburne field begins production.

And into the Future

RESEARCHING GAS HYDRATES

In conjunction with the Department of Energy (DOE), BP drilled a research well from Milne Point in 2007 to collect samples and gather knowledge about natural gas hydrates, a potential long-term global, unconventional gas energy resource. Gas hydrates exist all over the world, including offshore, but are especially prevalent in the Arctic. Natural gas hydrates contain from four to more than 40 times the amount of gas in place per cubic foot in comparison to other gas resources. This gas storage capacity makes gas hydrates a very attractive target. The research project recorded a number of firsts in Alaska, including the first significant gas hydrate-bearing core samples and the first delineation of a seismically-defined gas hydrate prospect. However, additional research is needed. Gas hydrates are a vast potential, though not presently commercial, source of additional natural gas.



Cold Heavy Oil Production with Sand (CHOPS)

BP's heavy oil test used the CHOPS technology for the first time in Alaska. CHOPS stands for cold heavy oil production with sand. Part of the test was to determine if the artificial lift system could pull sand in from the reservoir. That would create a network of channels or "wormholes" extending out from the well bore, to help the thick oil flow toward the well. This test was successful.

1987 BP acquires remaining share of Sohio for $7.7 billion and becomes world's third-largest oil company.

Endicott field, the first Arctic offshore production in the world, begins operations.

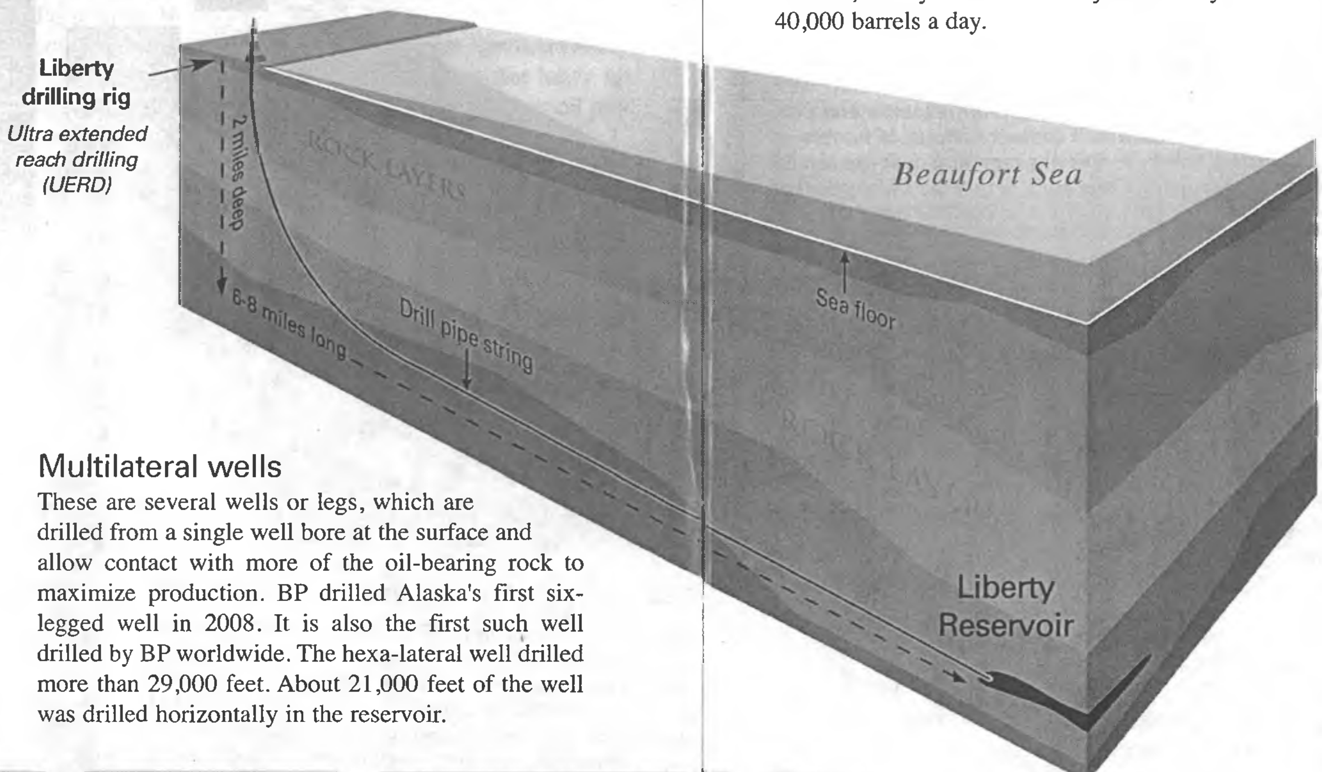
Drilling Technology

Directional drilling

This is part of a suite of advanced drilling technologies that reduce surface footprint, increase recovery and make it possible to reach parts of a reservoir once considered uneconomic. Drilling technology has advanced significantly since the start up of Prudhoe Bay. Directional drilling allows many more wells to be drilled from a surface location. Today, wells that were once spaced 120 feet apart are now as close as 10 feet, reaching a much larger subsurface area.

Horizontal drilling

This makes it possible to run long sections of horizontal casing through an oil-bearing layer as thin as six feet, draining the deposit through openings in the casing. This exposes much more of the reservoir, which results in higher production rates. A vertical well might expose 200-300 feet of oil bearing rock while the new wells can expose more than 20,000 feet.



Multilateral wells

These are several wells or legs, which are drilled from a single well bore at the surface and allow contact with more of the oil-bearing rock to maximize production. BP drilled Alaska's first six-legged well in 2008. It is also the first such well drilled by BP worldwide. The hexa-lateral well drilled more than 29,000 feet. About 21,000 feet of the well was drilled horizontally in the reservoir.

Extended reach drilling

Extended reach uses down-hole directional surveying equipment and drilling motors to reach formations 10,000 feet down and up to three miles from the drilling rig. It reduces cost, lowers environmental risk and shrinks the size of an operation's footprint. Advances in the drilling tools used down hole, such as measurement while drilling and mud motors, have enabled these pioneering advances.

Ultra extended reach drilling (UERD)

This technology is key to developing Liberty, a estimated recoverable 100-million-barrel field that lies offshore in the Beaufort Sea. Advances in drilling technology make it possible to develop the field from the existing Endicott satellite drilling island. These wells will reach out six to eight miles, some of the longest wells ever drilled. This requires a sophisticated drilling rig specially built for BP to develop Liberty. Producing the oil through these long-reach wells will eliminate the need for a new drilling island and subsea oil pipeline. Initial production is expected in 2011, and by 2013 the Liberty field will yield about 40,000 barrels a day.

1994 BP acquires Milne Point and Northstar fields.

1994 Point McIntyre & Niakuk fields begin production.

1997 Badami field begins production.

1998 BP-Amoco merger finalized.

1999 Prudhoe Bay field produces 10-billionth barrel.

ALASKA GAS

Alaska's North Slope natural gas is one of the largest undeveloped resources in BP's global portfolio, and bringing it to market is critical to BP's future plans in Alaska. In 2008, BP and ConocoPhillips launched a new company called Denali – The Alaska Gas Pipeline LLC. The project combines the financial strength, Arctic experience and technical resources of two of the most capable and experienced companies in the world.

The project

Denali - The Alaska Gas Pipeline will be the largest private construction project in North America. This joint venture is planning for the construction of a pipeline to deliver 4 billion cubic feet of natural gas a day from the North Slope of Alaska to markets in the Lower 48, Alaska and Canada and will provide the opportunity for access to gas along the pipeline route. Denali - The Alaska Gas Pipeline will generate billions of dollars in sales, royalties and taxes; promote new oil and gas exploration; and create new jobs and business opportunities.

Hard at work producing more oil

As gas commercialization efforts have been conducted over the years, North Slope gas has been injected back into the ground to maintain reservoir pressure and produce more oil. Alaska will recover billions of barrels of additional oil thanks to this gas recycling over the last 30 years. The best part of this story is that the same gas that was reinjected to produce more oil will be used again in the gas pipeline.

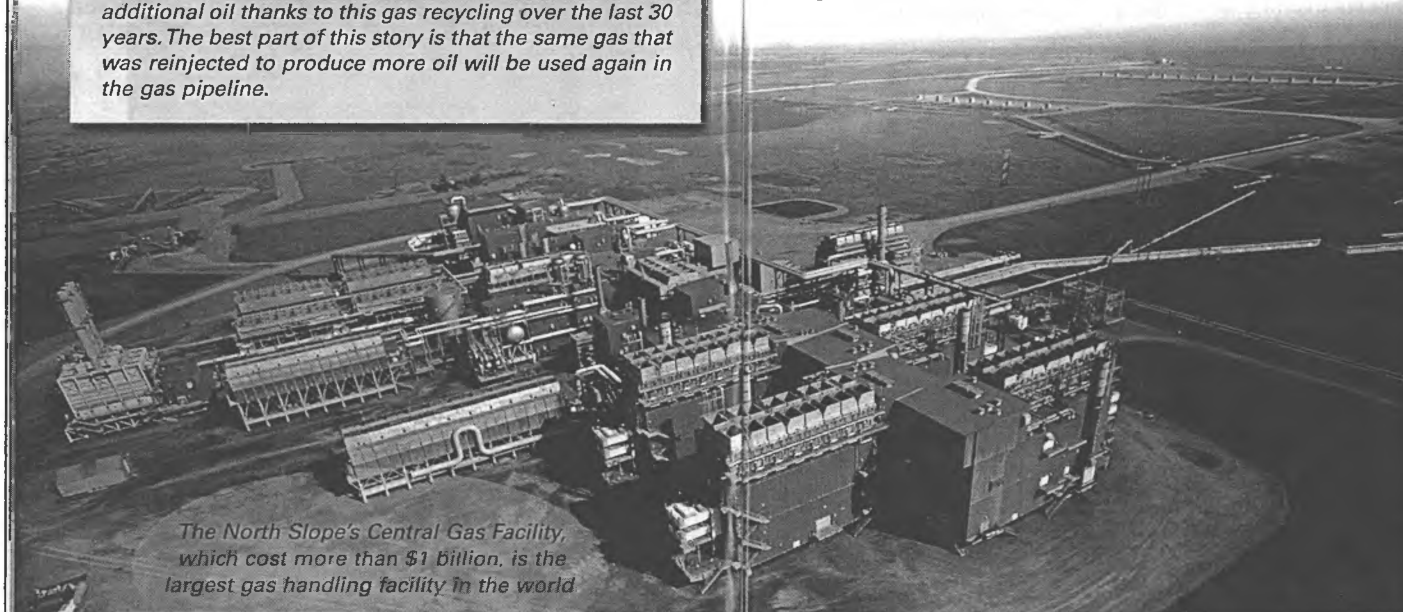
The resource

There are more than 35 trillion cubic feet of known gas resources on the North Slope and the U.S. Geological Survey (USGS) estimates there are many trillions more to be discovered. These resources can help fill North America's growing need for a long term, reliable, clean-burning source of energy. The North Slope gas resource is also vital to Alaska's future. North Slope oil production is steadily declining. The development of gas will make additional oil production feasible and help to extend the life of the North Slope oil fields for decades.

Project status

Denali – The Alaska Gas Pipeline project team completed its first season of summer field work in 2008 and established an Anchorage headquarters office. The initial major project milestone, an open season, will commence before year-end 2010. The open season is a process during which the pipeline company seeks customers to make long-term firm transportation commitments to the project.

After a successful open season, Denali – The Alaska Gas Pipeline intends to obtain Federal Energy Regulatory Commission (FERC) and National Energy Board (NEB) certification and move forward with project construction. The FERC and NEB certificates are the critical permits that provide U.S. and Canadian government authorization to construct a pipeline.



The North Slope's Central Gas Facility, which cost more than $1 billion, is the largest gas handling facility in the world

2000 ARCO acquisition and sale of ARCO Alaska assets to Phillips Petroleum, Inc. completed. Subsequent alignment of equity interest among Prudhoe Bay producers establishes BP as the sole operator of Prudhoe Bay.

2001 Northstar field begins production after sealift of largest module ever constructed in Alaska.

MOVING OIL AND GAS

Marine transportation

Four double-hulled, state-of-the-art Alaska-class tankers now transport BP's North Slope oil to refineries in Cherry Point, Washington, and Carson, California. These Alaska-class tankers set new standards for tanker technology and environmental performance. The vessels are the largest double-hulled tankers ever built in the U.S.

The ships represent an investment of more than $1 billion. National Steel & Shipbuilding Co. built the tankers at its shipyard in San Diego, California. The Alaska-class tankers are among the most environmentally friendly oil tankers ever launched, exceeding regulatory standards for new tankers.

Beyond the required double hulls, BP voluntarily incorporated additional environmental enhancements into the design, including complete redundancy in the propulsion, navigation and communication systems. With twin propellers, rudders and engine rooms, steering and propulsion can be maintained in the event one engine or rudder is taken out of service. The Alaska-class diesel electric engines reduce emissions, and some piping normally installed on the deck is located inside cargo tanks to reduce the risk of small spills. Seawater is used to cool the propeller shafts, virtually eliminating another risk of an oil release to the environment.

The Alaska Tanker Co.

The Alaska Tanker Co. (ATC) operates BP's Alaska tanker fleet. BP Oil Shipping Company USA, Keystone Alaska LLC and OSG America Operating Co., LLC own this Oregon based shipping consortium, which fully conforms to the requirements of the federal Jones Act.

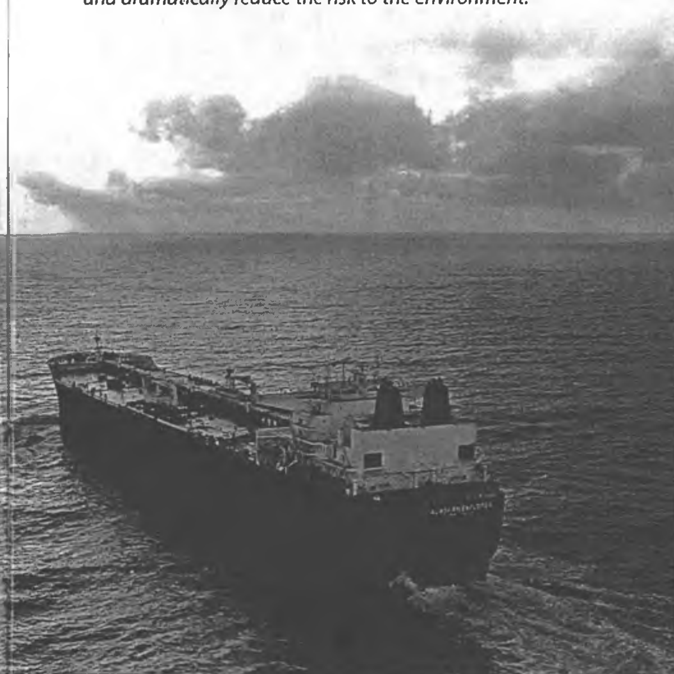
The Alaska Tanker Co. has been recognized for its outstanding safety and environmental record by the states of Alaska and Washington and it has received the U.S. Coast Guard's prestigious Benkert Osprey environmental award. As of 2009, the Alaska Tanker Company has completed more than 13 million man hours without a lost time injury.

Tanker and capacity

Alaskan Legend	1,300,000 bbls
Alaskan Explorer	1,300,000 bbls
Alaskan Frontier	1,300,000 bbls
Alaskan Navigator	1,300,000 bbls

www.aktanker.com

BP's new double hull tankers exceed regulatory standards and dramatically reduce the risk to the environment.



2002 TAPS right-of-way renewed for 30 more years.

2003 BP divests its North Slope exploration acreage to focus on known oil and gas resources.

Badami field is shut in due to poor reservoir performance.

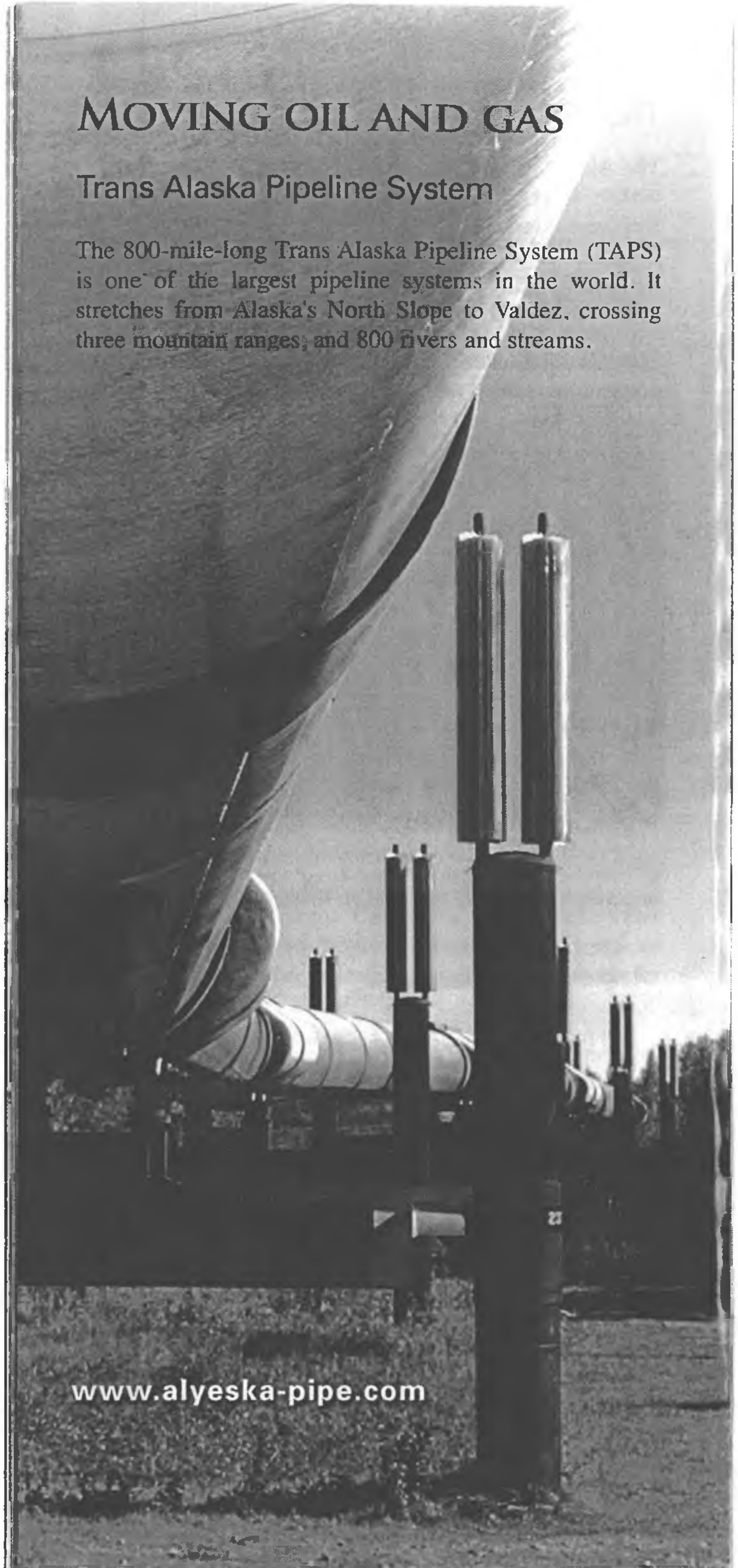
2004 First of four new double-hull, "Alaska class" tankers begins service in the Alaska trade.

MOVING OIL AND GAS

Trans Alaska Pipeline System

The 800-mile-long Trans Alaska Pipeline System (TAPS) is one of the largest pipeline systems in the world. It stretches from Alaska's North Slope to Valdez, crossing three mountain ranges, and 800 rivers and streams.

www.alyeska-pipe.com



2004

Operations Support Center brings smart board technology to enhance Slope operations.

BP and ConocoPhillips sanction West Sak, largest heavy oil program on North Slope.

TAPS ownership:

Operator:

Alyeska Pipeline Service Company

Owners:

BP Pipelines (Alaska) Inc.	46.93%
ConocoPhillips Transportation Alaska, Inc.	28.29%
ExxonMobil Pipeline Company	20.34%
Koch Alaska Pipeline LLC	3.08%
Unocal Pipeline Company	1.36%

TAPS Facts:

TAPS average daily throughput (2008)
703,551 barrels/day

TAPS total throughput (2008)
257.5 million barrels

TAPS cumulative throughput since startup (1977)
15.7 billion barrels of oil equivalent

Pipeline diameter
48 inches

Construction cost
> $8 billion in 1977

Valdez Marine Terminal

Storage capacity
9.18 million barrels

Tankers loaded (thru April 2008)
19,625

Construction cost
> $1.4 billion

Other pipelines

In addition to TAPS, BP owns 38% of the Kuparuk Transportation Co., 68% of the Endicott Pipeline Co., 100% of the Milne Point Pipeline LLC, 99% of the Northstar Pipeline.

2005

North Slope production exceeds 15 billion BOE.
Alyeska Pipeline Service Co. begins major upgrade to extend life and improve efficiency of Trans Alaska Pipeline System.

Greater Prudhoe Bay

After more than 30 years of production, Prudhoe Bay remains the largest oil field in North America and ranks among the 20 largest fields ever discovered. When production started at the Prudhoe Bay field the recovery rate of the 25 billion barrels of oil in place was expected to reach 40 percent. Today, using new technologies that estimate has increased to more than 60 percent.

The initial producing area of Prudhoe Bay field has produced more than 12 billion barrels, of which BP's net cumulative production is approximately 4.6 billion barrels of oil equivalent (BOE). Production from the Prudhoe Bay initial producing area averaged approximately 314,000 BOE per day in 2008. The Energy Information Administration estimates the field also contains an estimated recoverable 26 trillion cubic feet of natural gas in an overlying gas cap and in solution with the oil.

Prudhoe Bay produces from the Sadlerochit sandstone formation, nearly 9,000 feet below sea level. The oil bearing column is 500 feet thick in some areas. The Greater Prudhoe Bay Area, which includes the fields of Prudhoe Bay, its satellite fields and the Greater Point McIntyre Area fields, in total produce about 392,000 BOE per day. Cumulative production has exceeded 13 billion barrels; BP's net share is 4.8 billion barrels.

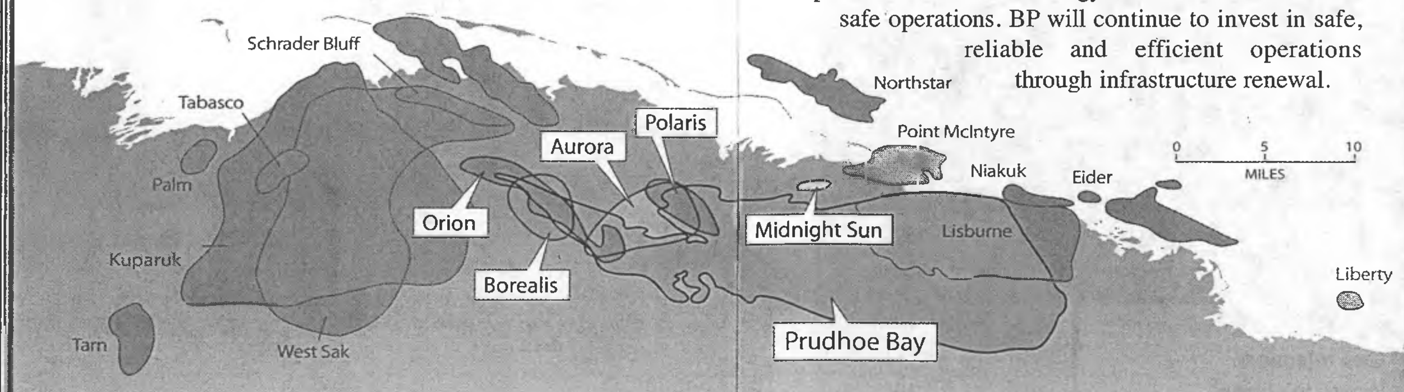
BP's net production from Greater Prudhoe Bay Area averages approximately 98,000 barrels of oil equivalent per day (BOED). Prudhoe Bay was discovered in 1968 and came on-stream June 20, 1977. Production averaged more than 1.5 million barrels of oil and gas liquids per day for more than a decade.

Prudhoe Bay satellites

Satellite fields are smaller accumulations of oil that can often be developed using existing infrastructure. The average daily production from Prudhoe Bay satellites is about 45,700 barrels of oil equivalent per day. BP's net share of that production is about 8,600 barrels. There are five satellite fields currently producing and the liquids are processed through the field's main facilities. Aurora and Borealis satellite fields produce from similar formations. Midnight Sun produces from a sandstone formation at 8,000 feet below sea level. Orion and Polaris fields both produce the difficult heavy oil from the Schrader Bluff formation, at depths of 4,000 to 5,000 feet below sea level. By using advanced drilling technologies we are growing this important resource. The Prudhoe Bay satellite fields have produced more than 118 million barrels of oil equivalent. BP's net cumulative production is approximately 23.4 million barrels of oil equivalent.

Prudhoe Bay renewal

BP completed replacing 16-miles of oil transit lines and put these lines into service in late 2008. The project included rebuilding the main Prudhoe Bay oil delivery system, pigging modules, corrosion inhibitor injection facilities, state-of-the-art leak detection, metering facilities and all the affiliated electrical and emergency systems. This $500 million project incorporates the best technology and materials to ensure safe operations. BP will continue to invest in safe, reliable and efficient operations through infrastructure renewal.



2006	Fourth Alaska Class tanker delivered.		
2007	Prudhoe Bay and TAPS mark 30th anniversary since start up.	Endicott marks 20th anniversary	
2008	BP completes rebuilding 16 miles of transit lines at Prudhoe Bay.	BP sanctions Liberty development.	
2009	BP marks 50th anniversary in Alaska.		

Oil Fields	Prudhoe Bay	Midnight Sun	Aurora
Owners	BP (Operator) ~26% ConocoPhillips ~36% ExxonMobil ~36% Chevron ~2%	BP (Operator) ~26% ConocoPhillips ~36% ExxonMobil ~36% Chevron ~2%	BP (Operator) ~26% ConocoPhillips ~36% ExxonMobil ~36% Chevron ~2%
Field Data			
Participating Field Area	213,543 acres (includes satellite fields)	3,112 acres	7,519 acres
Original Oil in Place	25 billion barrels	0.6 billion barrels	0.1 billion barrels
Original Gas in Place	45 trillion SCF	0.1 trillion SCF	0.1 trillion SCF
Cumulative Oil Production	**Gross Field**	**Gross Field**	**Gross Field**
Production (12/31/08) (millions of barrels of oil equivalent)	12,260	17.3	25.5
Current Rates (12/31/08)	**Gross Field**	**Gross Field**	**Gross Field**
Oil (thousands barrels/day)	289	2.2	8.9
Gas (millions SCF/day)	8,301		
Water (thousands bbl/day)	1,067.4		
Number of Wells			
Oil Producers	1,128	2	20
Gas Injection	34	0	0
Water Injection	88	3	11
WAG Injection	0	0	0

Oil Fields	Orion	Polaris	Borealis
Owners	BP (Operator) ~26% ConocoPhillips ~36% ExxonMobil ~36% Chevron ~2%	BP (Operator) ~26% ConocoPhillips ~36% ExxonMobil ~36% Chevron ~2%	BP (Operator) ~26% ConocoPhillips ~36% ExxonMobil ~36% Chevron ~2%
Field Data			
Participating Field Area	18,853 acres	11,681 acres	7,557 acres
Original Oil in Place	1.2 billion barrels	0.5 billion barrels	0.1 billion barrels
Cumulative Oil Production	**Gross Field**	**Gross Field**	**Gross Field**
Production (12/31/08) (millions of barrels of oil equivalent)	14.5	8.2	52.8
Current Rates (12/31/08)	**Gross Field**	**Gross Field**	**Gross Field**
Oil (thousands barrels/day)	14.5	5.2	14.9
Number of Wells			
Oil Producers	17	11	35
Gas Injection	0	0	0
Water Injection	19	8	14
WAG Injection*	0	0	1

** Water Alternating Gas Injector*

GREATER POINT MCINTYRE

The Greater Point McIntyre Area encompasses Point McIntyre field and the nearby satellite fields of West Beach, North Prudhoe Bay, Niakuk and Western Niakuk. The Lisburne Production Center processes fluids from Point McIntyre Area fields and the Lisburne field. Production averaged about 40,900 barrels per day in 2008. Cumulative production from the Greater Point McIntyre area is 717 million barrels of oil equivalent. BP's cumulative net production is approximately 165 million barrels of oil equivalent.

Point McIntyre

Located seven miles north of Prudhoe Bay, the Point McIntyre field was discovered in 1988 and came on-line in 1993. Point McIntyre contained an estimated 900 million barrels of oil in place, of which about 500 million barrels is recoverable with existing technology. The field's production peaked in 1996 at 170,000 barrels per day. Production averaged about 27,000 barrels per day in 2008. BP produces the field from two gravel drill site pads. Production rates are maintained through drilling new wells, enhanced oil recovery methods and upgrades to facilities.

Drill rig at Point McIntyre.

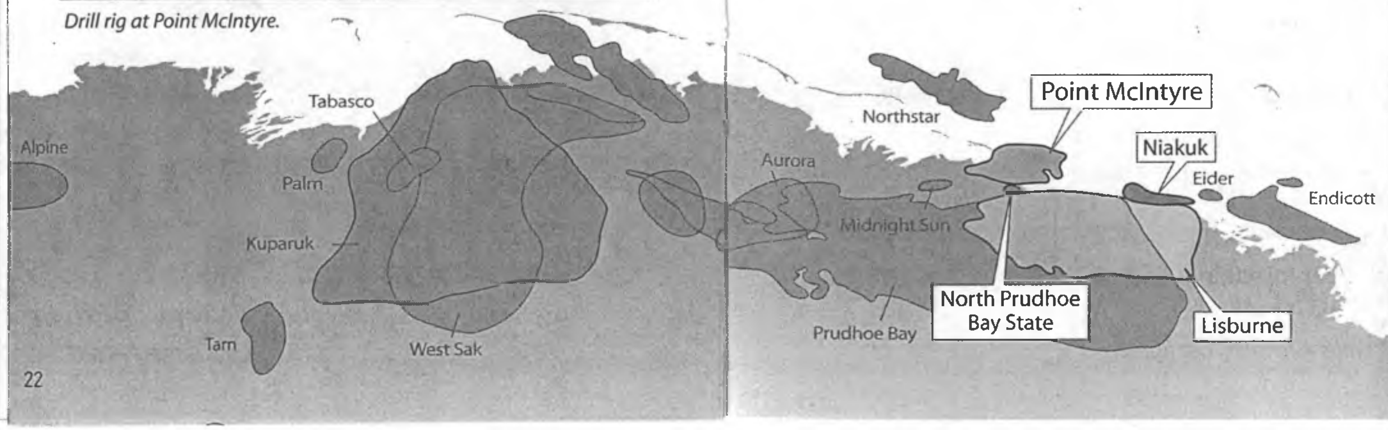
Niakuk

The Niakuk field lies offshore and contain about 300 million barrels of original oil in place. Production in 2008 averaged about 5,500 barrels per day from the lower Cretaceous Kuparuk River formation, a structurally and stratigraphically complex formation.

Lisburne Processing Center

Lisburne

The Lisburne field is a complex, fractured carbonate reservoir that lies underneath and adjacent to the main Ivishak reservoir at Prudhoe Bay. The field was discovered in 1968 along with the Prudhoe Bay field and came on-stream in late 1986. The field contained an estimated 1.8 billion barrels of oil in place. Production averaged about 8,400 barrels per day in 2008. Cumulative production from the Lisburne field is is nearly 189 million barrels of oil equivalent. BP's cumulative net production from the field is approximately 44 million barrels of oil equivalent. Horizontal drilling technology using coiled tubing drilling, along with geosciences techniques to identify fracture and fault locations, have increased production rates in recent years.



The Niakuk field lies offshore of the Prudhoe Bay.

Oil Fields	Point McIntyre	Niakuk	Lisburne
Owners	BP (Operator) ~26% ConocoPhillips ~36% ExxonMobil ~36% Chevron ~2%	BP (Operator) ~26% ConocoPhillips ~36% ExxonMobil ~36% Chevron ~2%	BP (Operator) ~26% ConocoPhillips ~36% ExxonMobil ~36% Chevron ~2%
Field Data			
Participating Field Area	10,834 acres	6,443 acres	79,929 acres
Original Oil in Place	0.8 billion barrels	0.2 billion barrels	1.8 billion barrels
Original Gas in Place	0.9 trillion SCF	0.1 trillion SCF	0.3 trillion SCF
Cumulative Oil Production	Gross Field	Gross Field	Gross Field
Production (12/31/08) (millions of barrels of oil equivalent)	434	91.3	188.5
Current Rates (12/31/08)	Gross Field	Gross Field	Gross Field
Oil (thousands BOE/day)	27	5.5	8.4
Number of Wells			
Oil Producers	61	18	79
Gas Injection	1	0	4
Water Injection	9	7	0
WAG Injection*	6	0	0

** Water Alternating Gas Injector*

Milne Point Operations Center has accommodations for about 300 workers. Because of its isolation from other North Slope facilities, the facility is a self-contained community which includes a cafeteria, medical clinic, warehouse, waste treatment facility, fire response equipment, and recreational facilities.

MILNE POINT UNIT

Milne Point - Kuparuk Schrader Bluff*

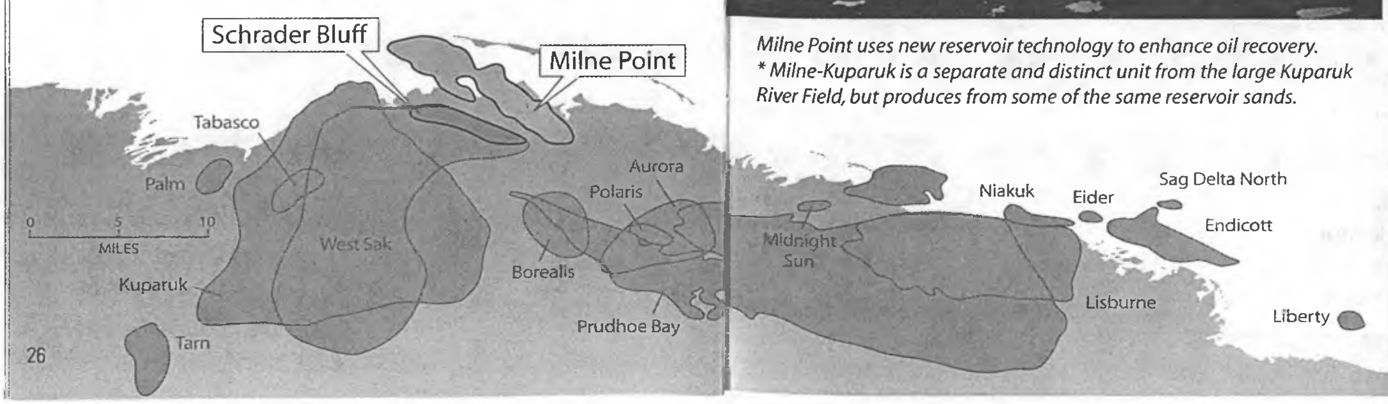
Located about 40 miles west of Prudhoe Bay, Milne Point has become an innovator in the application of new reservoir technology to enhance oil recovery. Today the field produces about 32,200 barrels of oil equivalent per day (BOED). BP's net production is about 28,000 BOED. Cumulative oil production at Milne Point is 273 million barrels of oil and BP's net production is about 231 million barrels. Milne was discovered in 1969 by Conoco and began production in 1985. BP became operator in 1994. Milne produces from three main reservoirs.

The Kuparuk and the Sag River reservoirs are lighter oil horizons and the Schrader Bluff produces a variety of heavy oil termed heavy or viscous oil, with the consistency of cold syrup. BP has been a leader in the development of the heavy oil resource using horizontal multilateral drilling. This oil is colder and thicker than other North Slope oil. All production fluids are processed through the Milne Point Unit production facilities. BP is also evaluating the potential of even heavier fluids from shallower formations. BP will continue its Ugnu heavy oil development project at Milne. For more information on this project, go to page 8 of this publication.

Oil Fields	Milne Point - Kuparuk Schrader Bluff*
Owners	BP (Operator) 99.4% Anadarko 0.6%
Field Data	
Participating Field Area	49,668 acres
Original Oil in Place (gross)	0.92 billion barrels
Cumulative Oil Production	**Gross Field**
Production (12/31/08) (millions of barrels of oil equivalent)	273.3
Current Rates (12/31/08)	**Gross Field**
Oil (thousands BOE/day)	32.2
Gas (thousands SCF/day)	20.4
Water (thousands bbl/day)	76
Number of Wells	
Oil Producers	149
Gas Injection	1
Water Injection	70
WAG Injection*	27

** Water Alternating Gas Injector*

Milne Point uses new reservoir technology to enhance oil recovery.
** Milne-Kuparuk is a separate and distinct unit from the large Kuparuk River Field, but produces from some of the same reservoir sands.*



The Kuparuk field is the third largest producing oil field in North America.

GREATER KUPARUK AREA

The Kuparuk field is the third largest field in North America. Discovered in 1969, Kuparuk began production in December 1981 and achieved a record average rate of 322,000 barrels per day in 1992. The producing reservoir is composed of Cretaceous-age Kuparuk sands at depths of 5,500 to 6,500 feet. The Greater Kuparuk area produced about 142,000 barrels of oil equivalent per day (BOED) in 2008. BP's net production is 48,000 BOED. Cumulative production from the Greater Kuparuk Area is 2.3 billion barrels of oil equivalent (BOE). BP's cumulative net production is approximately 800 million BOE.

BP holds major ownership in the Greater Kuparuk Area, which includes the satellite fields of Tarn, Tabasco, Meltwater and West Sak. ConocoPhillips is the field operator. The production from these fields is processed through the Kuparuk production facilities. Processed oil from Kuparuk is piped 26 miles to Pump Station 1, the beginning of the Trans Alaska Pipeline System.

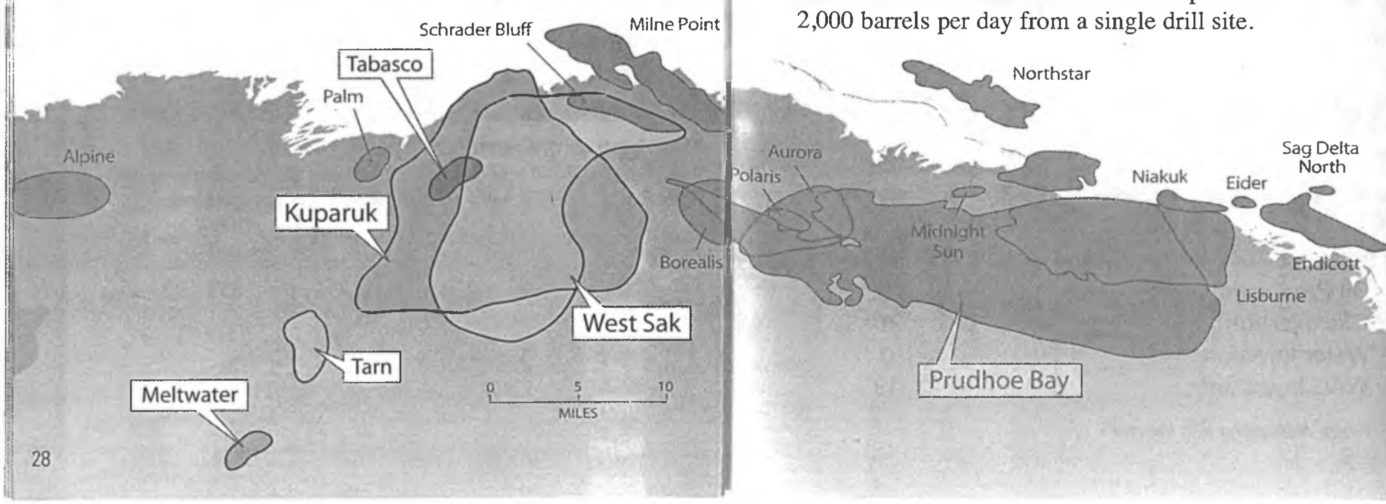
In 2008 a commercial processing agreement was reached to allow production from the Pioneer-operated Oooguruk field to be produced through the Kuparuk facilities.

Kuparuk satellite fields

The Kuparuk satellite fields include Tarn, Tabasco, Meltwater and the heavy oil West Sak field. In 2008, the combined average daily production from the satellites was 37,800 barrels of oil equivalent.

West Sak oil production in 2008 averaged 17,100 barrels per day. Since start up in 2004, the cumulative production from West Sak is about 39 million barrels of oil equivalent.

Tabasco is the second heavy oil development in the area. It began production in 1998 and is situated near the western end of the Greater Kuparuk Area. Tarn produced about 15,200 barrels per day in 2008. It began production in 1999 and is located southwest of the Kuparuk field. Located 10 miles south of Tarn, Meltwater was discovered n 2000 and produces about 2,000 barrels per day from a single drill site.



Oil Fields	Kuparuk	West Sak	Tabasco
Owners	ConocoPhillips (OP) ~55.2% BP ~39.2% Chevron ~5% ExxonMobil ~0.6%	ConocoPhillips (OP) ~52.2% BP ~37% Chevron ~5% ExxonMobil ~5.8%	ConocoPhillips (OP) ~55.3% BP ~39.3% Chevron ~5% ExxonMobil ~0.4%
Field Data			
Participating Field Area	185,000 acres	30,000 acres	4,000 acres
Original Oil in Place	5.9 billion barrels	3.0 billion barrels*	0.2 billion barrels*
Original Gas in Place	2.7 trillion SCF		
Cumulative Oil Production	Gross Field	Gross Field*	Gross Field
Production (12/31/08) (millions of barrels of oil equivalent)	2,142	39	15
Current Rates (12/31/08)	Gross Field	Gross Field	Gross Field
Oil (thousands BOE/day)	104	17.1	3.2
Number of Wells			
Oil Producers	478	37	9
Gas Injection	0	0	0
Water Injection	239	35	3
WAG Injection*	163	0	0

** Excludes over 9 billion barrels of West Sak heavy oil outside the core area*

Oil Fields	Tarn	Meltwater
Owners	ConocoPhillips (OP) ~55.3% BP ~39.3% Chevron ~5% ExxonMobil ~0.4%	ConocoPhillips (OP) ~55.4% BP ~39.4% Chevron ~5% ExxonMobil ~0.2%
Field Data		
Participating Field Area	12,000 acres	7,000 acres
Original Oil in Place	0.3 billion barrels	0.1 billion barrels
Cumulative Oil Production	Gross Field	Gross Field
Production (12/31/08) (millions of barrels of oil equivalent)	91	3.1
Current Rates (12/31/08)	Gross Field	Gross Field
Oil (thousands BOE/day)	15.2	2.3
Number of Wells		
Oil Producers	32	12
Gas Injection	0	0
Water Injection	0	0
WAG Injection*	18	7

** Water Alternating Gas Injector*

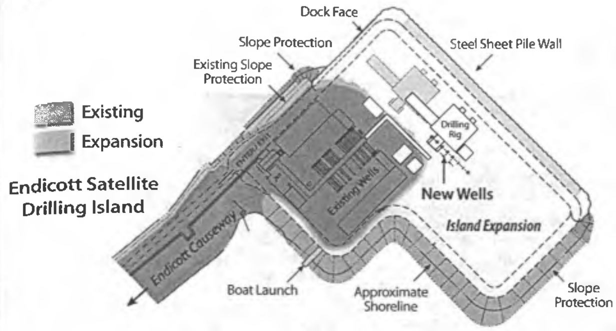
ENDICOTT

Located less than three miles offshore, Endicott is the first continuously producing offshore field in the Arctic. Average production from the Endicott field was about 14,700 barrels of oil per day in 2008. Cumulative production from the Endicott field is 448 million barrels of oil. BP's cumulative net oil production is approximately 258 million barrels.

The field also set the mark for a reduced footprint development on Alaska's North Slope. Endicott's surface footprint is 70 percent smaller than the traditional North Slope development pad. Using advanced drilling techniques, the field was developed with deviated wells drilled from two artificial islands, each located in about 20 feet of water. Endicott is connected with shore by a causeway. The 45-acre Main Production Island contains the living quarters, operations center and processing facilities. Endicott's oil-bearing rocks lie in the Kekiktuk formation, a shale and sandstone formation similar to the Sadlerochit in the Prudhoe Bay field. The oil column lies about 10,000 feet beneath the surface and consists of the highest quality reservoir. Discovered in 1978, the field began production in 1987 and reached its peak production of 120,000 barrels per day in the early 90s.

Endicott is recognized for its outstanding safety record and in 2008 celebrated five years without without a day away from work case (DAFWC) incident. The facility also holds the Occupational Safety and Health Administration (OSHA) Voluntary Protection Program (VPP) star award.

Endicott is the first continuously producing off shore field in the Arctic.

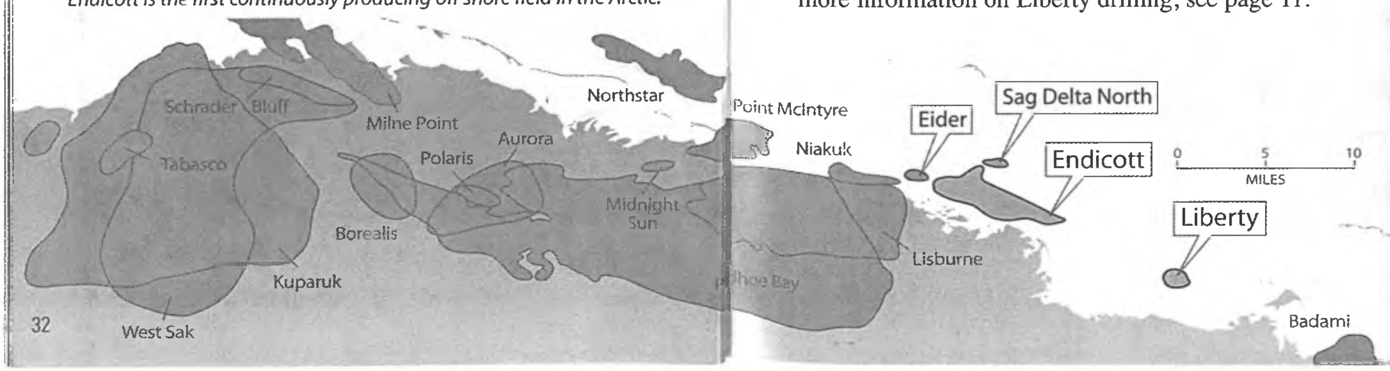


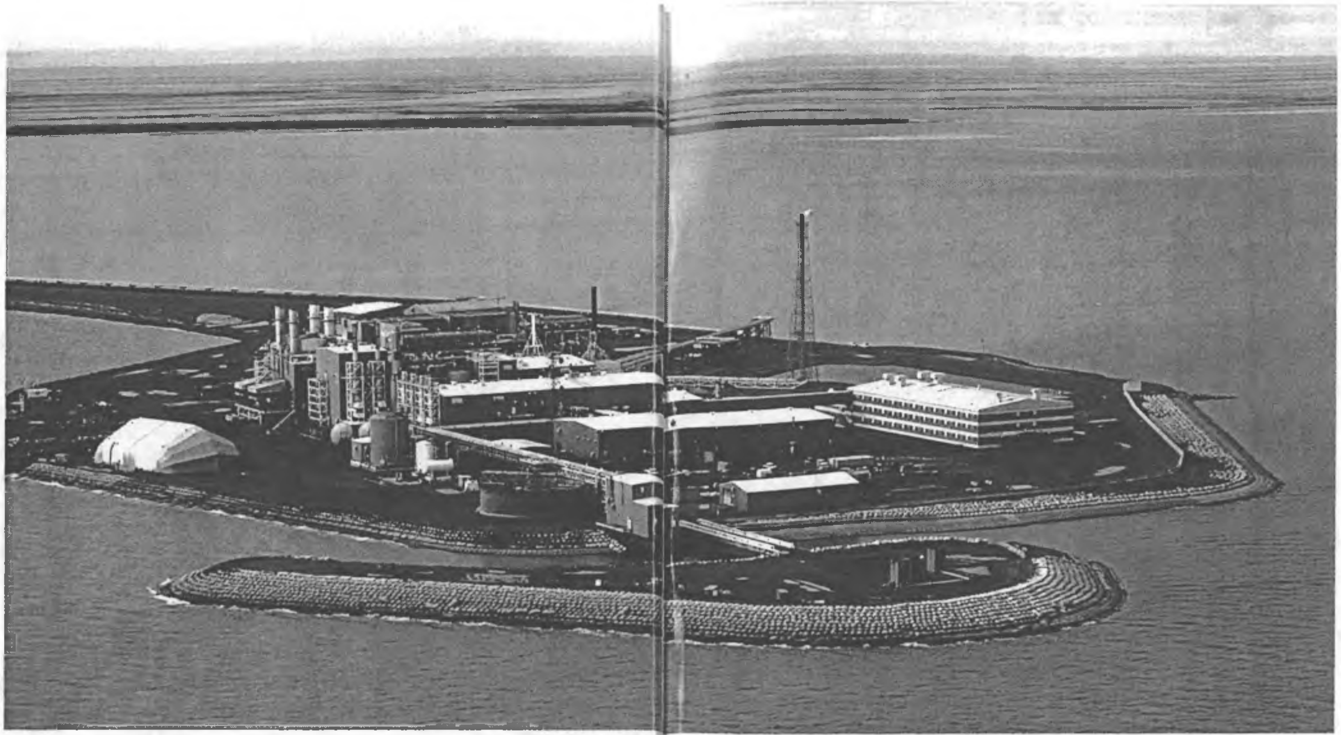
Advances in drilling technology make it possible to develop the Liberty field from the existing Endicott satellite drilling island. Producing the oil through these long-reach wells will eliminate the need for a new drilling island and subsea oil pipeline.

LIBERTY

In 2008 BP announced it was moving ahead with the Liberty development. Liberty is the first offshore project in Alaska fully located in federal waters. BP also launched construction of a specialty-built drilling rig needed to drill the ultra extended reach Liberty wells, which will reach out six to eight miles. BP anticipates Liberty drilling will begin in 2010. Oil production is expected to start up in 2011 and will ramp up to about 40,000 barrels per day. That new oil production will help offset the declining production from the mature North Slope oilfields, and keep oil flowing down the Trans Alaska Pipeline.

Field development will ultimately cost approximately $1.5 billion, with recovery of an estimated 100 million barrels of oil. Drilling will occur from an existing satellite pad that is part of the BP-operated Endicott oil field. Liberty will make use of the Endicott causeway and oil processing facility. This enhances safety, provides year-round overland access, and maximizes environmental protection while minimizing the project's footprint. This project design has eliminated the need for the construction of new processing facilities, an offshore drilling island or offshore pipeline. For more information on Liberty drilling, see page 11.

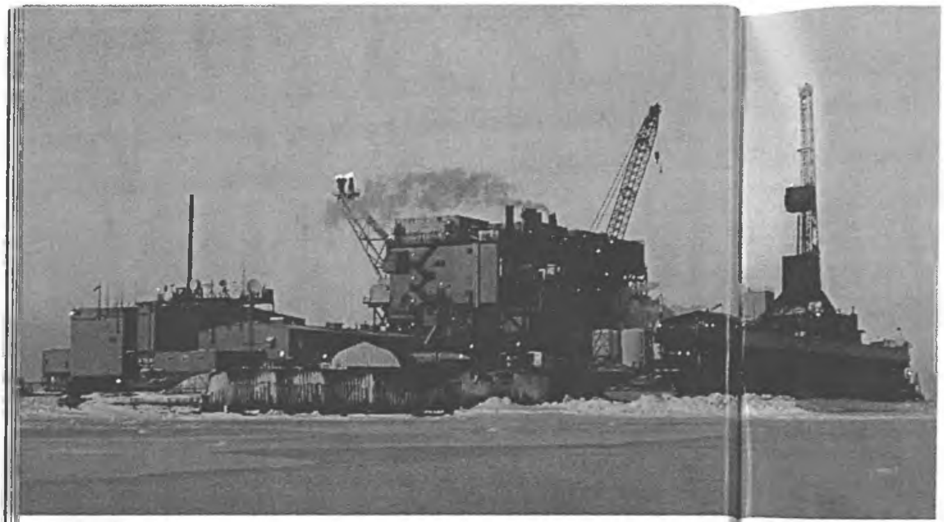




The first of the small-footprint fields, Endicott's entire production facilities and camp facilities fit onto a 45-acre island.

Oil Fields	Endicott	Eider	Sag Delta North
Owners	BP (Operator) ~67.9% ExxonMobil ~21.0% Chevron ~10.5% Others ~0.6%	BP (Operator) ~100%	BP (Operator) ~98.1% NANA ~1.4% Doyon, Ltd. ~0.5%
Field Data			
Participating Field Area	17,547 acres	690 acres	1,150 acres
Original Oil in Place	1.1 billion barrels	0.015 billion barrels	0.014 billion barrels
Original Gas in Place	1.2 trillion SCF	0.052 trillion SCF	
Cumulative Oil Production	Gross Field	Gross Field	Gross Field
Production (12/31/08) (millions of barrels of oil equivalent)	448	2.8	8.2
Current Rates (12/31/08)	Gross Field	Gross Field	Gross Field
Oil (thousands BOE/day)	14.7	0	0.234
Gas (thousands SCF/day)	373	0	0.2
Water (thousands bbl/day)			1.2
Number of Wells			
Oil Producers	58	2	2
Gas Injection	5	0	0
Water Injection	18	0	2
WAG Injection*	1	0	0

* *Water Alternating Gas Injector*



Northstar's production facilities were built in Alaska and sea lifted to the North Slope.

NORTHSTAR

Located about five miles northwest of Prudhoe Bay in about 39 feet of water, Northstar is the first Arctic offshore field connected to shore only by a subsea pipeline. Northstar was developed by BP in 1995 and started production in 2001. The unit sits in state and federal waters and in 2008 produced about 31,300 barrels of oil equivalent (BOE) per day from the Ivishak and Shublik formations. BP's net production is about 23,000 BOE per day. Cumulative production from Northstar is about 134 million BOE; BP's net share is approximately 98 million BOE.

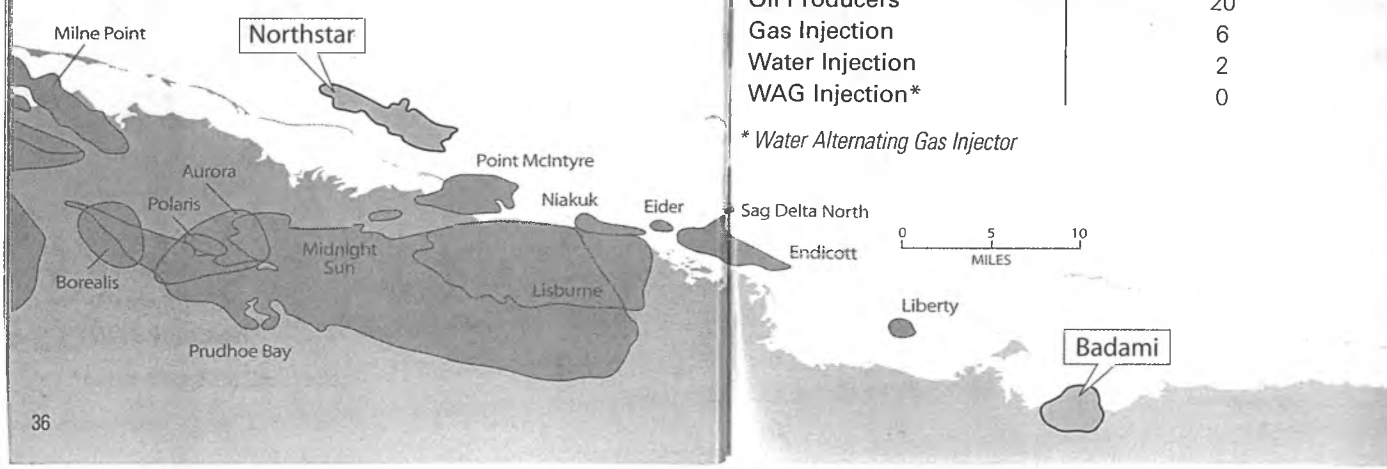
BP designed a state-of-the-art facility that produces and processes the field's fluids from a five-acre production island that is protected from sea ice by concrete armor, a steel sheet pile wall and underwater bench and berm system. The six-mile subsea pipeline has a wall thickness triple that of typical onshore North Slope pipelines and is buried three times the depth of the deepest ice gouges surveyed. An innovative, triple-redundant leak detection system monitors the pipeline.

BADAMI

Badami production was suspended in late August of 2007 to allow the reservoir time to recharge. In 2008 BP reached an agreement with Savant Alaska LLC, under which Savant will drill additional exploratory and development wells at Badami. The first of these wells was spudded in March 2009. The current plan of development for the Badami Unit runs until November 2010. BP owns 100 percent of Badami.

Oil Fields	Northstar
Owners	BP (Operator) ~98.6% Murphy Oil ~1.4%
Field Data	
Participating Field Area	17,682 acres
Original Oil in Place	176 million barrels
Cumulative Oil Production	**Gross Field**
Production (12/31/08) (millions of barrels of oil equivalent)	134
Current Rates (12/31/08)	**Gross Field**
Oil (thousands BOE/day)	31.3
Gas (thousands SCF/day)	507
Water (thousands bbl/day)	15
Number of Wells	
Oil Producers	20
Gas Injection	6
Water Injection	2
WAG Injection*	0

** Water Alternating Gas Injector*



SUMMARY

BP North Slope Oil Fields		
Original Oil in Place Original Gas in Place	42.3 billion barrels 52.8 trillion SCF	
Cumulative Production	**BP Net**	**Gross Field**
Oil (12/31/08) (billions of barrels of oil equivalent)	6.3	15.7*
Current Rates (12/31/08)	**BP Net**	**Gross Field**
Oil (thousands BOE/day)	204.3	471

*TAPS Throughput since 1977

Field area

Unit boundaries equal about 693,484 acres.

Roads and causeways

408 miles

Distance covered

Approximately 80 miles across from the eastern edge of Badami to the western edge of Kuparuk. Approximately 30 miles from the northern edge of Northstar to the southern edge of Meltwater. (This includes open and roadless areas between facilities and open ocean around Northstar and Endicott.)

North Slope Facts

The North Slope is a flat, treeless plain, which extends 88,000 square miles, from the foothills of the Brooks Mountain Range to the Arctic Ocean and west from the Canadian border to the Chukchi Sea. The developed area of the North Slope encompasses about 312 square miles.

Location

Prudhoe Bay is about 600 air miles north of Anchorage and about 1,200 miles south of the North Pole. It is about 250 miles north of the Arctic Circle.

Weather

Winter temperatures across the North Slope frequently dip to minus 30 degrees Fahrenheit with winds to 30- 40 miles per hour, resulting in severe chill factors. The lowest recorded temperature was minus 68 degrees Fahrenheit. Temperatures can rise to 80 degrees Fahrenheit during July.