

SCOMM

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Official Business

ALASKA STATE LEGISLATURE

HOUSE SPECIAL COMMITTEE ON OIL AND GAS

Representative Kurt Olson, Chair
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Representative Ralph Samuels
Representative Nancy Dahlstrom
Representative Scott Kawasaki

Representative Jay Ramras
Representative Mark Neuman
Representative Mike Doogan

Monday, October 22, 2007

9am – noon

1:30 – 5pm

AGENDA

HB 2001 - Oil and Gas Production Tax Amendments

Presentations by: Industry Stakeholders

- **BP Exploration**
Claire Fitzpatrick, BP's Commercial Senior Vice President
Mike Utsler, BP's Senior Vice President – Prudhoe Bay
- **ConocoPhillips**
Kevin Mitchell - Vice President, Finance & Administration
Jim Taylor - Vice President, Commercial Assets
- **Brooks Range Petroleum**
Ken Thompson – via phone



BP Presentation on HB 2001

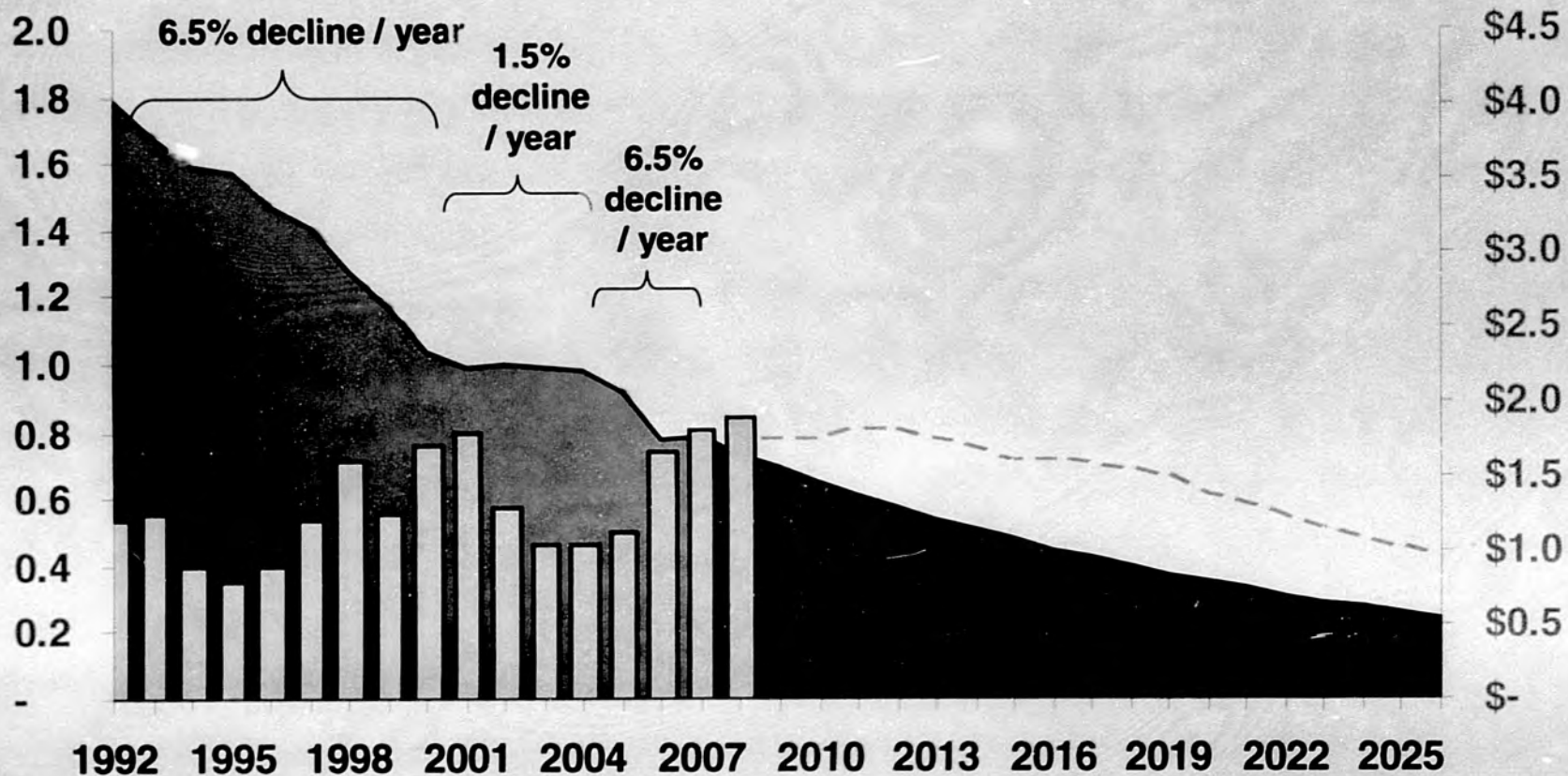
Claire Fitzpatrick and Mike Utsler
October 22, 2007

Key Messages



- **Production**, not tax rate, is the major factor in determining state revenue for the future years
- Delivering the State's production forecast will require tens of billions of **investment**
- **Investment decisions** are made on the **combination** of strategy, resource prospects, technology, economics including **fiscal policy**, and risk.
- The proposed bill significantly **deteriorates economics on 70%** of investment options in the next 20 years
- Higher prices and developing technology could give the Alaska fields a new lease on life, but huge **investments are needed**

The State's production and revenue forecast counts on higher than historical investment



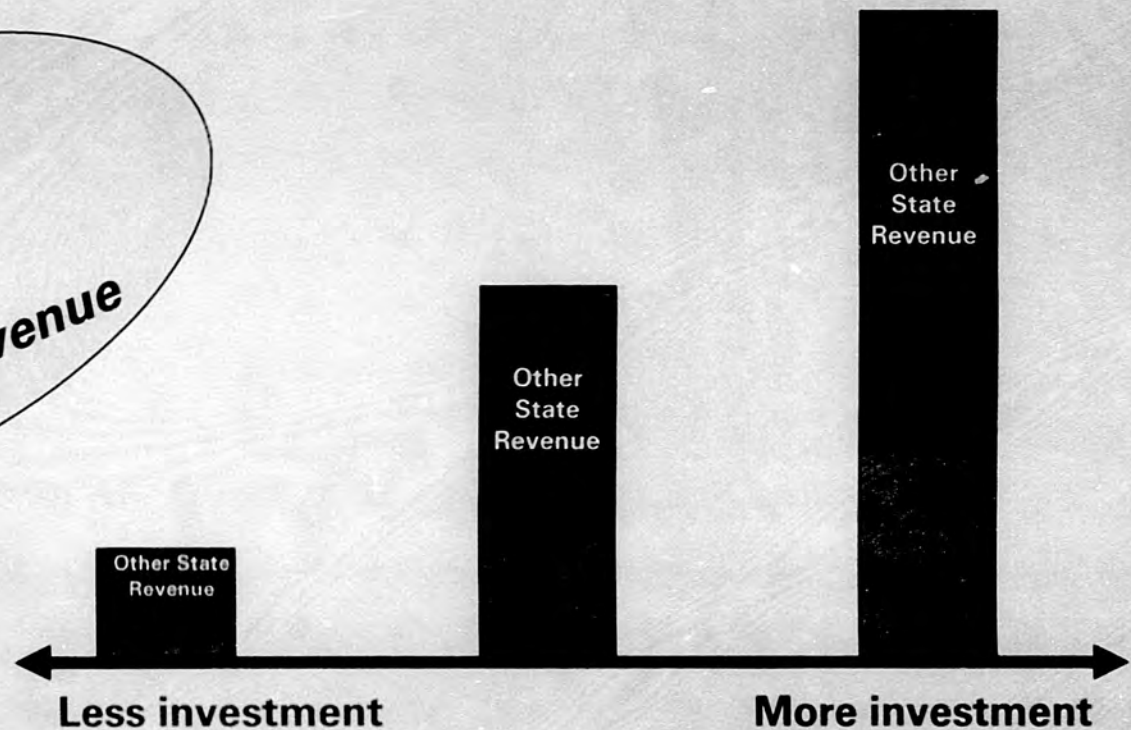
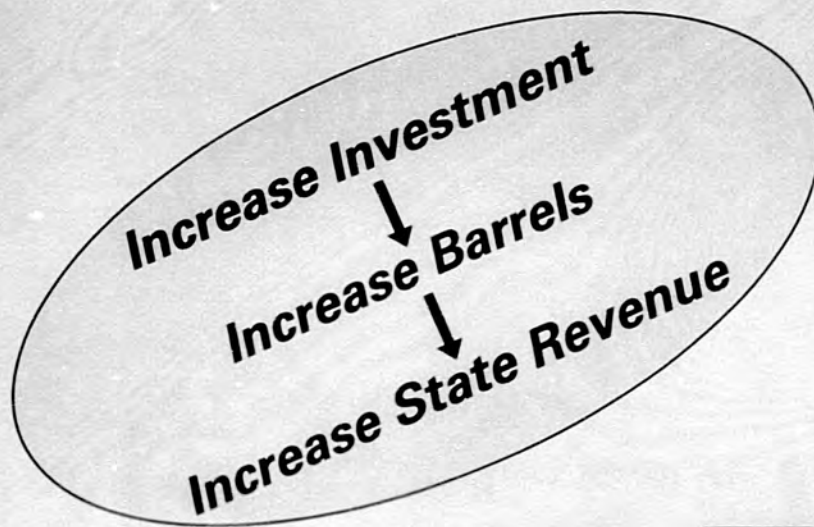
□ DOR Forecast
■ Actual Production

■ 6% Production Decline from 2008
□ Capital Spend Estimate

Production Drives Revenue



Decline Rate	15%	6%	3%
Produced Barrels	1.3 bn	3.9 bn	7.5 bn
Industry Investment	\$5 bn	\$25 bn	\$70 bn
		Status quo	





ALASKA NORTH SLOPE OIL

80 YEARS OF ONGOING DEVELOPMENT



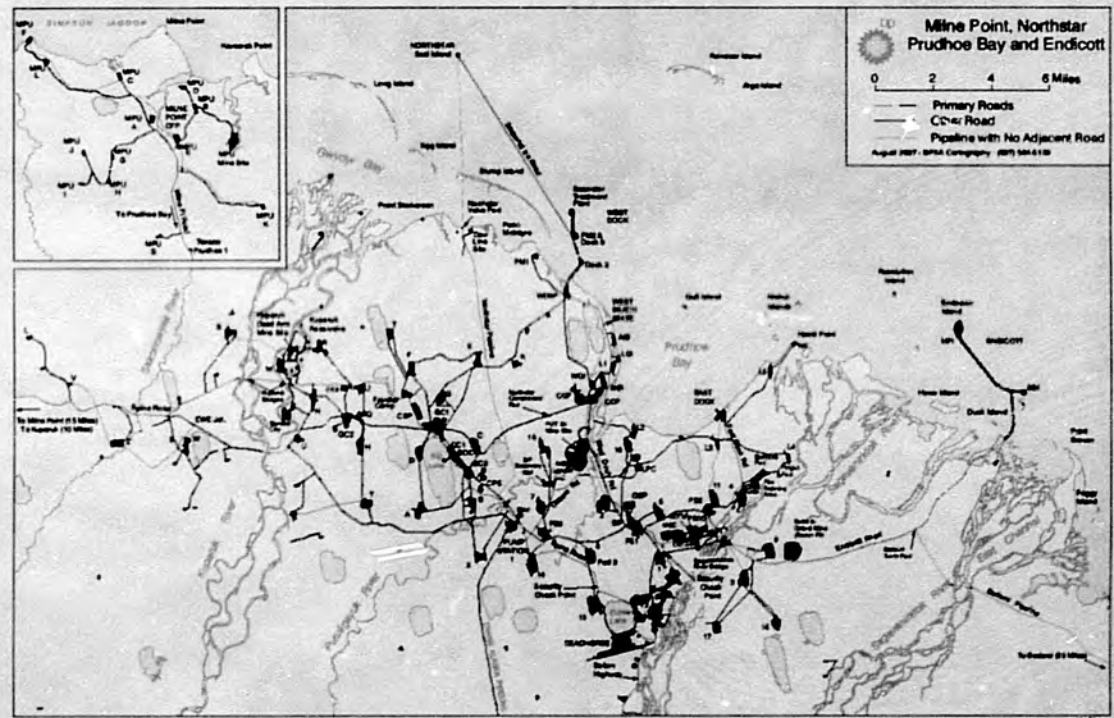
Mike Utsler
BP Exploration (Alaska)
October 22, 2007



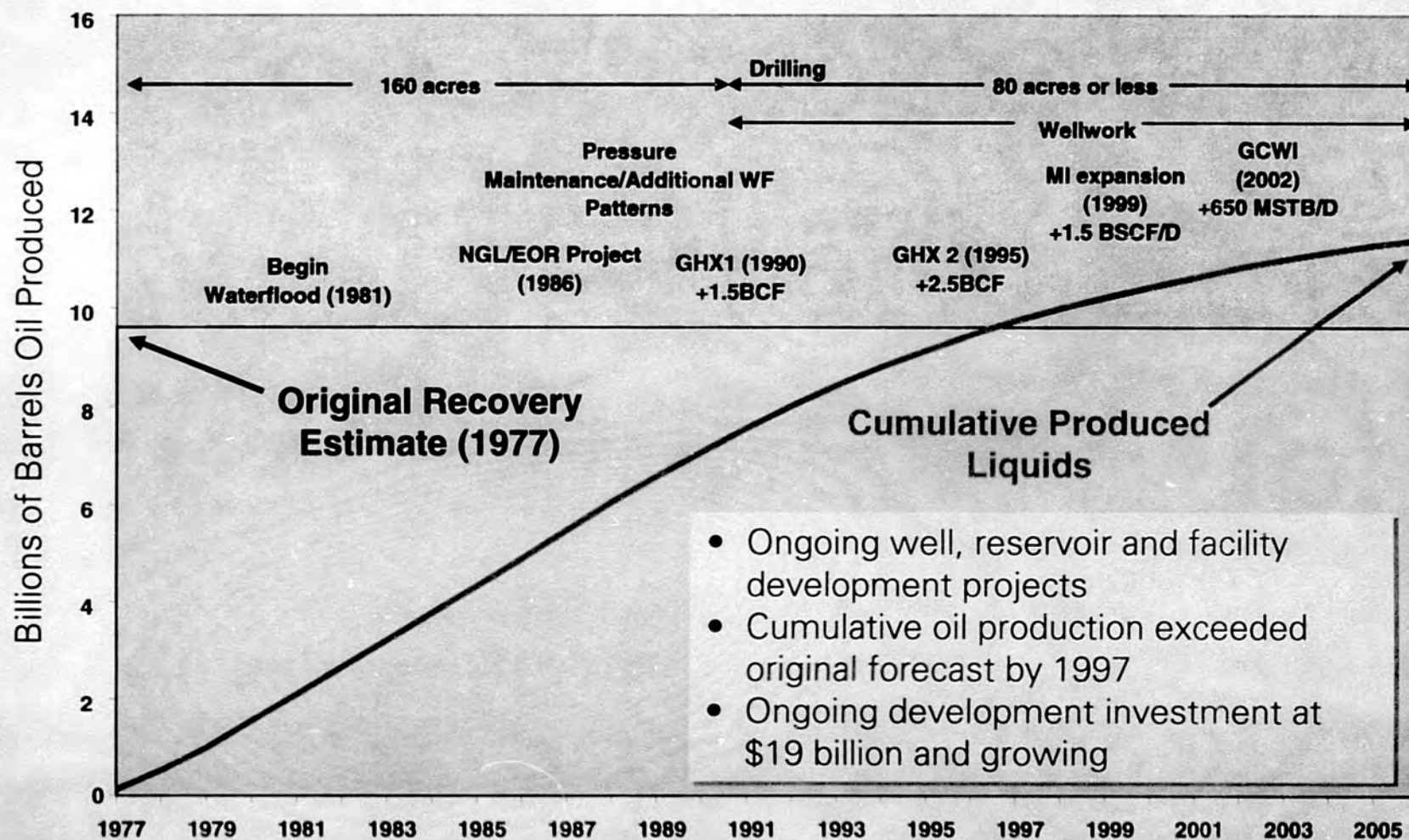
Prudhoe Bay



- Largest Oil Field in North America
- Extensive and successful development
 - 60 square miles
 - 11 major facility locations
 - 42 Drill sites
 - 1200 active wells
- Future challenges
 - Managing declining oil rate, and increasing water and gas rates
 - Ongoing developments, light and heavy oil, to offset steep natural decline
- Technology development and deployment is key
 - Arctic specific
 - Advanced reservoir processes
 - World class drilling and workover
 - Facility upgrades



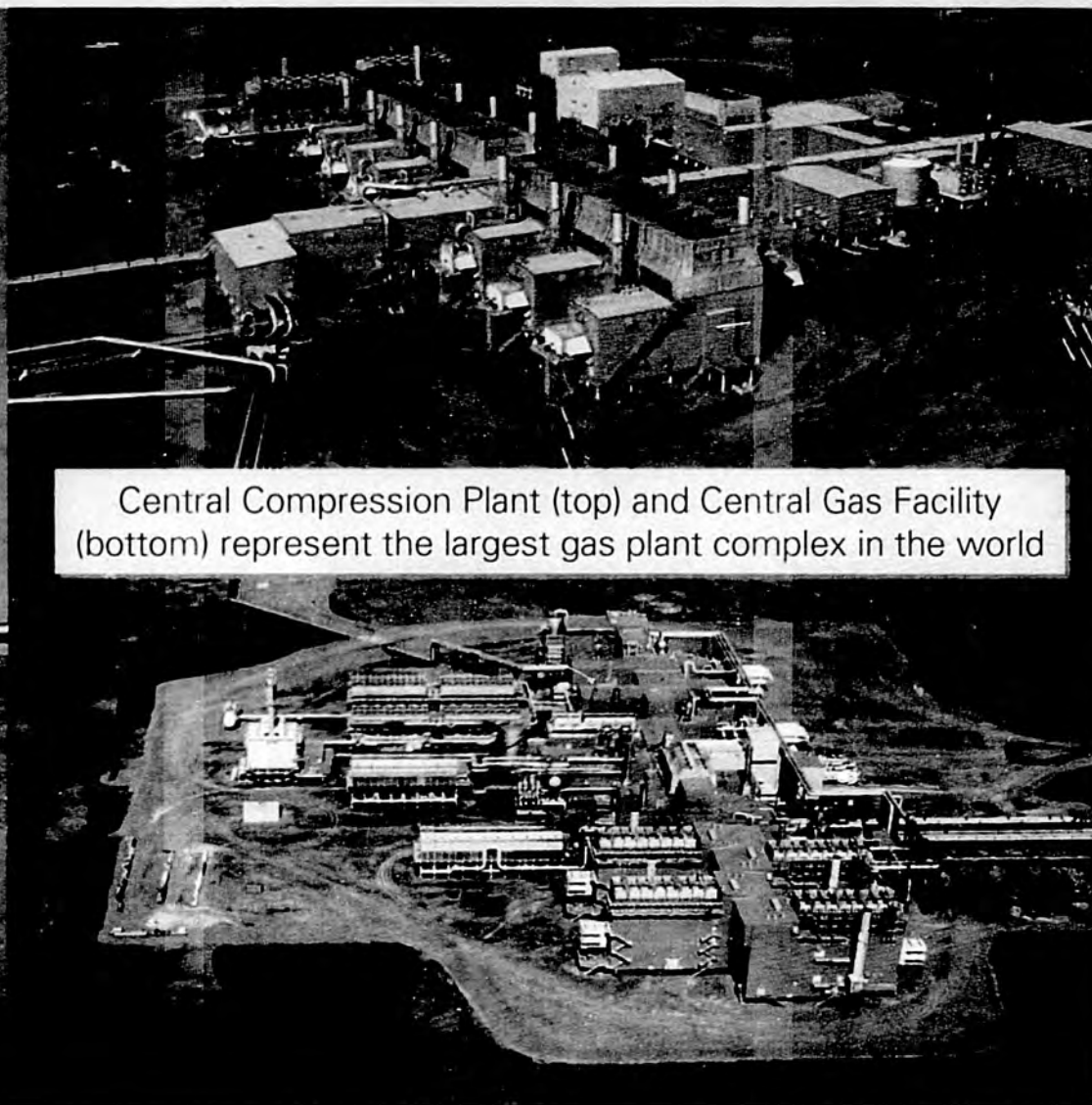
Prudhoe Bay Development History



Prudhoe Gas Facilities

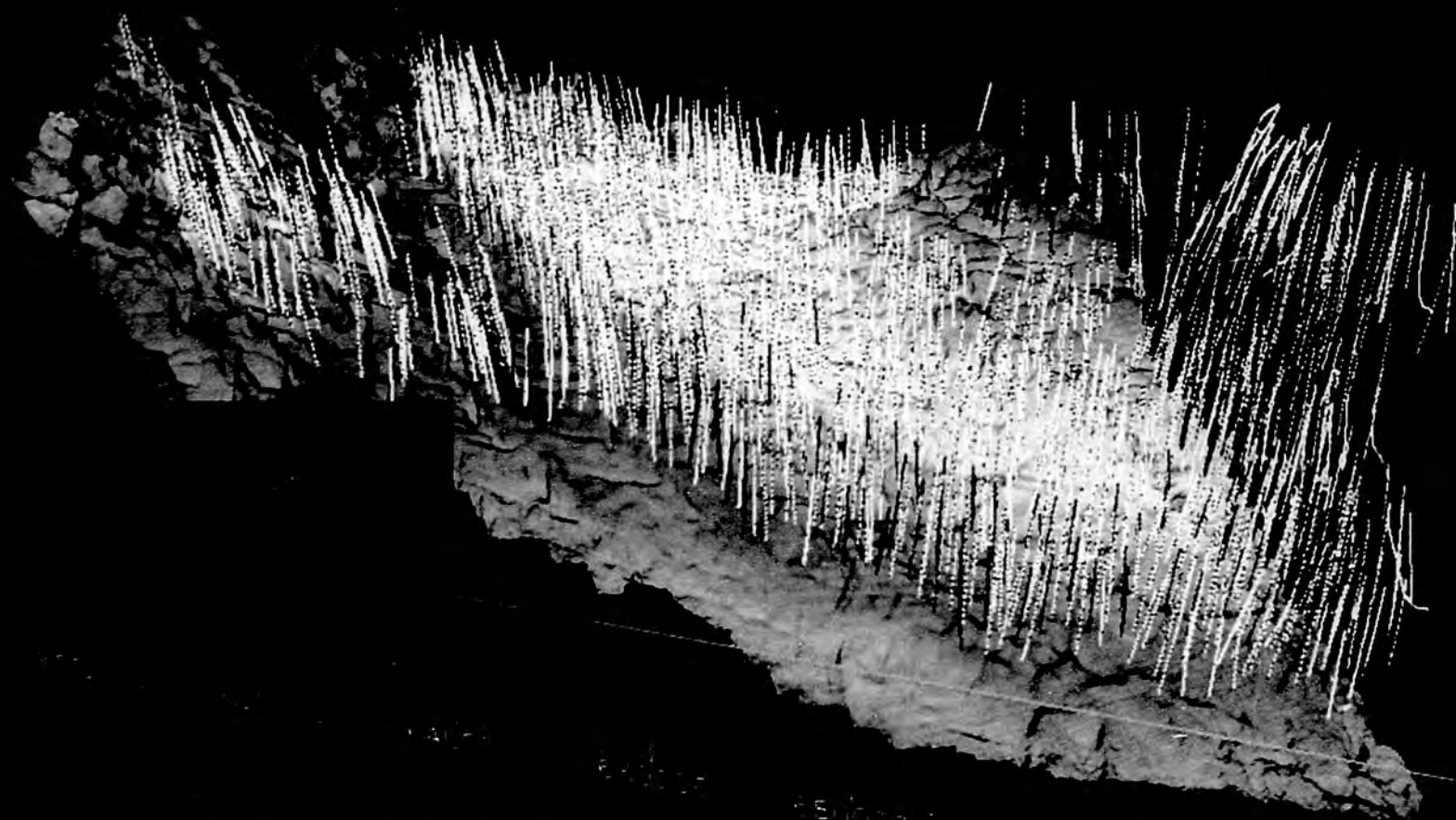


Gas handling expansion module being moved from sealift barge to installation site.



Central Compression Plant (top) and Central Gas Facility (bottom) represent the largest gas plant complex in the world

Over 2500 Wells Drilled in Prudhoe Bay



Originally expected to drill only 500 wells

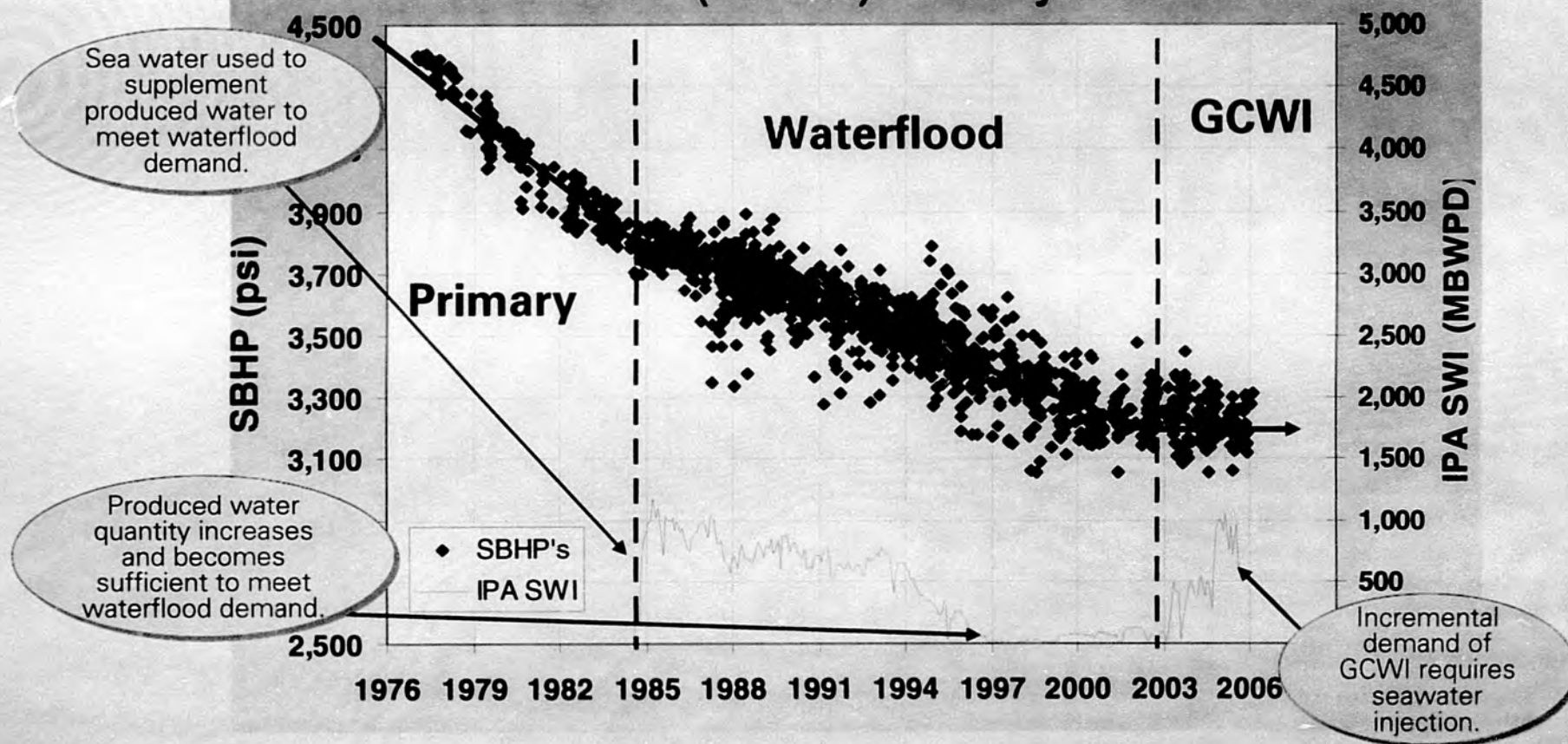
Pt
Ac

Water Injection Projects



Water injection into the oil reservoir (i.e., waterflood) to maintain field pressure followed by new Gas Cap Water Injection (GCWI) technology

Shut-in Bottom Hole Pressure (SBHP) History



Projects: Bright Water™



Objective

- Increase Oil recovery through improved sweep efficiency
- Reduce produced water

Concept:

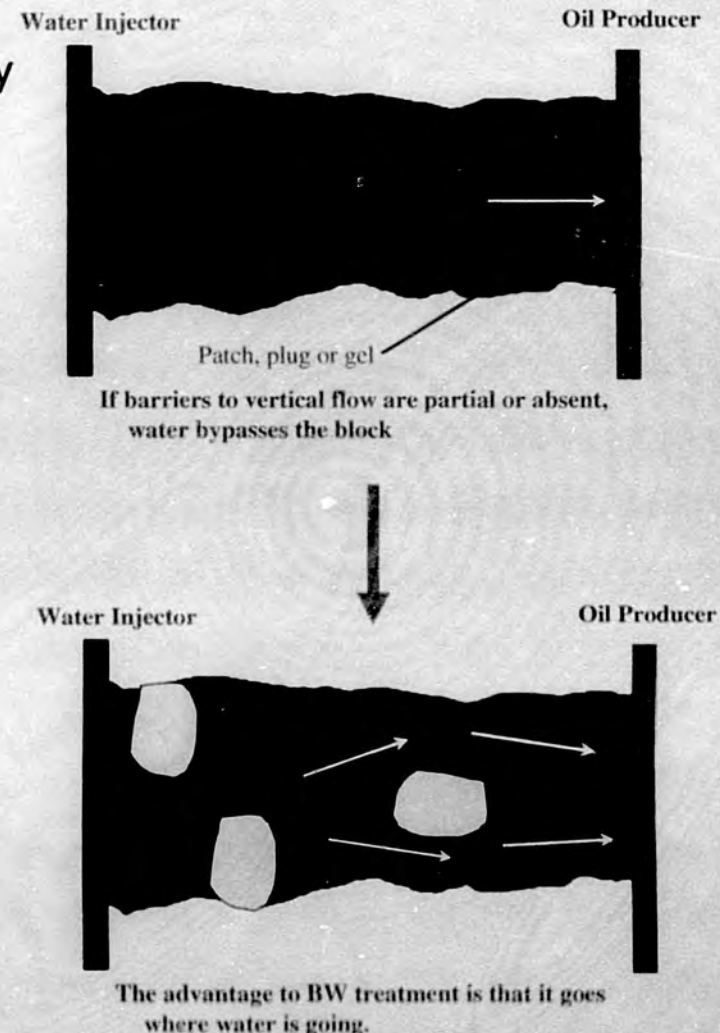
Polymer expands after deep penetration into reservoir, effectively blocking the swept zones and forcing the water into unswept oil zones. Timing for expansion and change in sweep is 9 months. Lab testing shows 2%-20% additional recovery.

2006 Highlights:

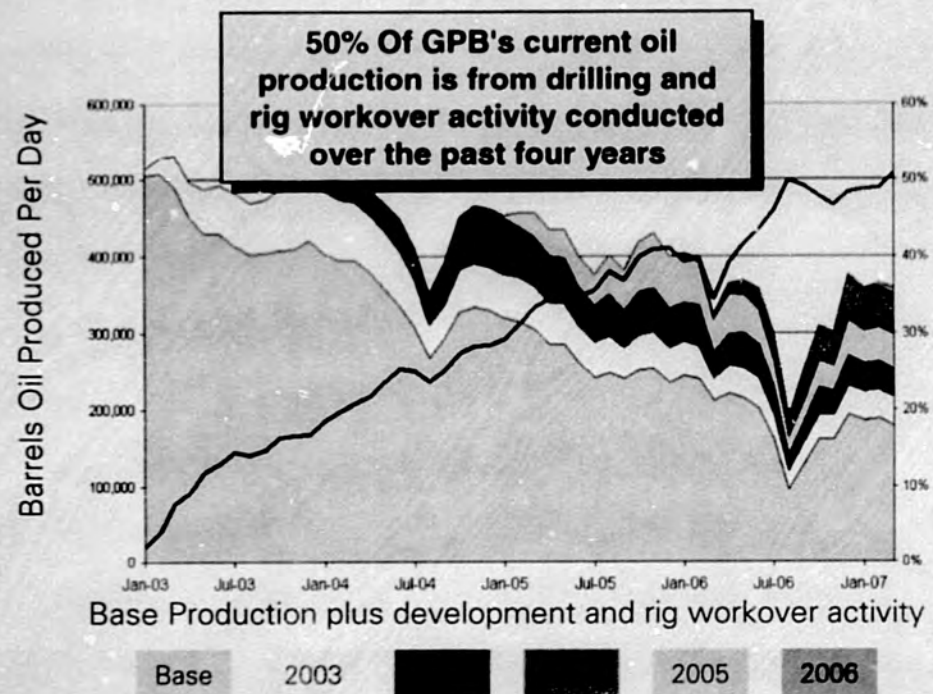
- NWFB Trial: limited response due to design and operational difficulties
- FS2 Trial: measurable response in 7 offsets

2007 Plan:

- Continued monitoring of FS2 and NWFB trials
- Pursuing additional treatments

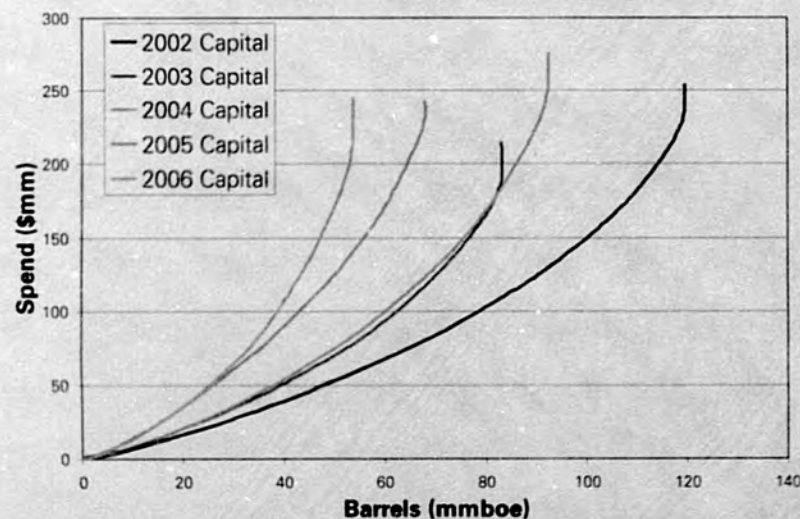


New Wells and Wellwork Deliver Barrels

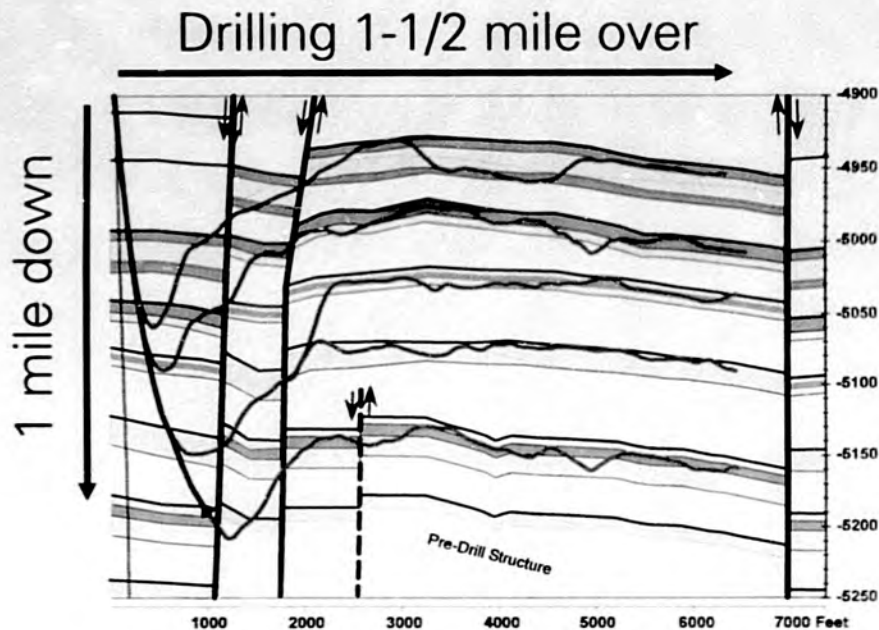


Each year, the challenge to delivering more barrels becomes greater

GPB Well Investments 2002-2006

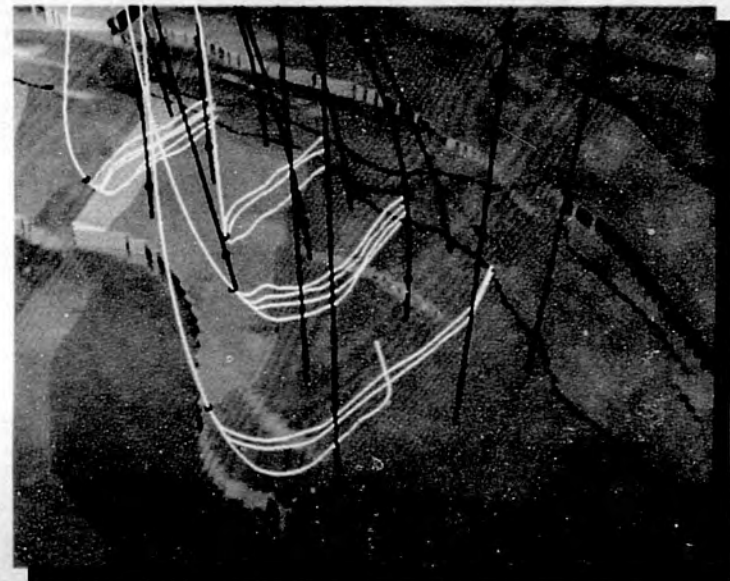


Seismic Imaging and Directional Drilling Enable Development

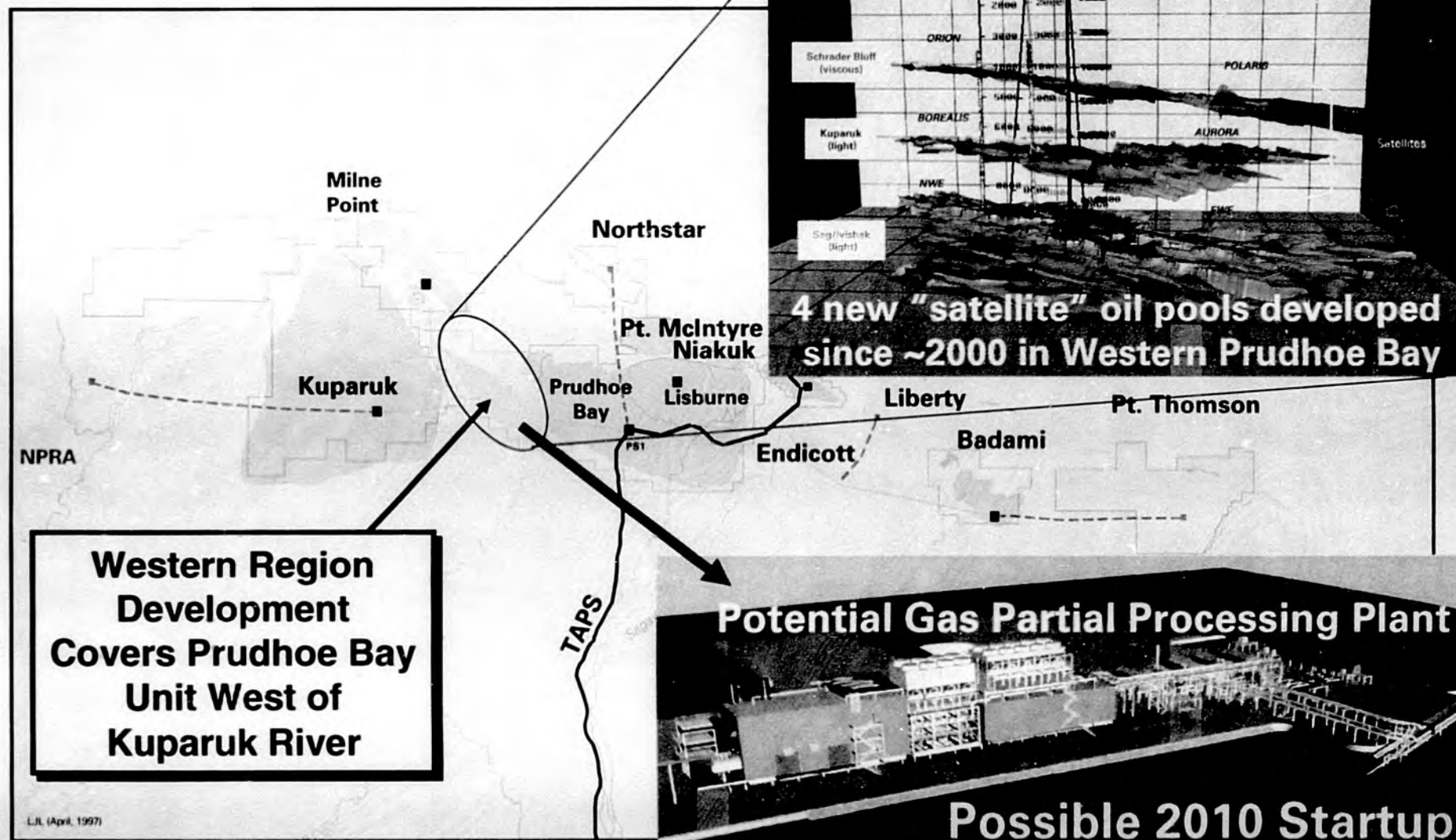


**Technologies required to drill
and operate these multi-
lateral well did not exist eight
years ago**

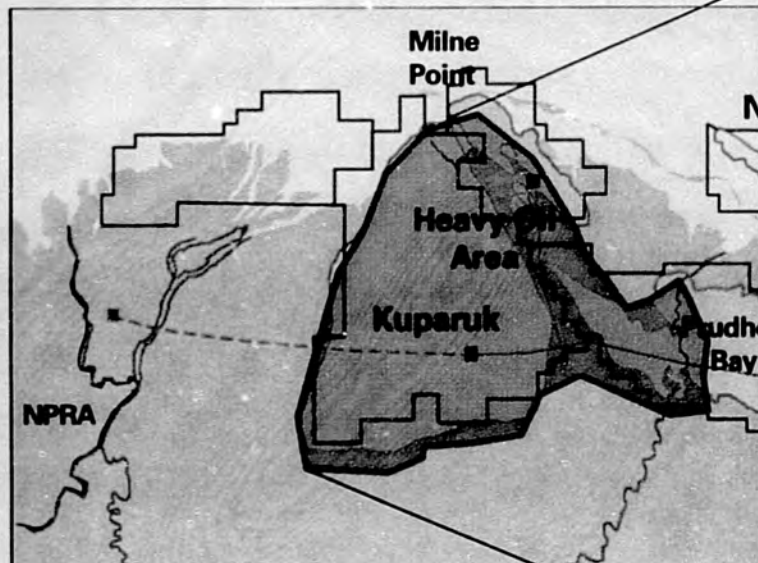
**Now 15 are producing and
over 20 more are planned,
but not all are approved**



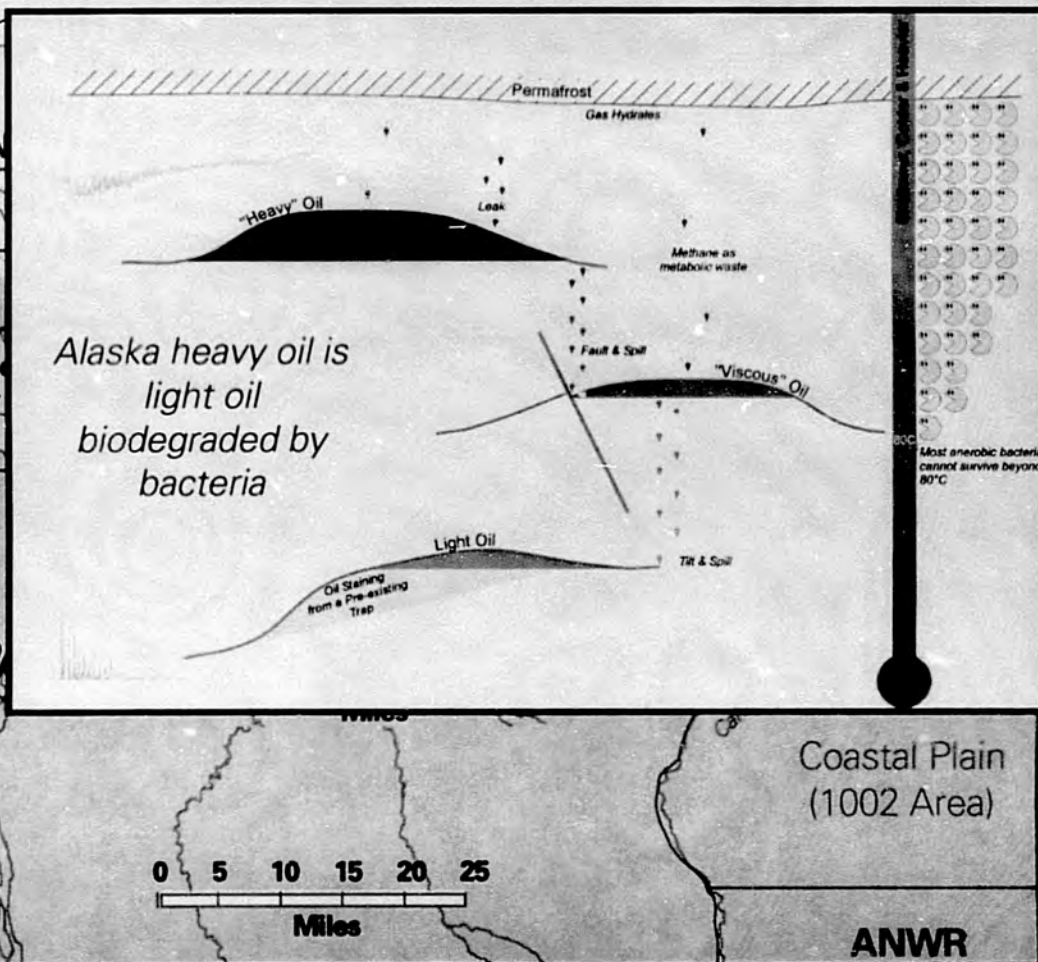
Western Region Prudhoe Bay



North Slope Heavy Oil



- Alaska Heavy Oil: 25 – 30 billion barrels oil in place
- Creating new technologies to overcome challenges
- Pilot trials began decades ago
- Only 100 million barrels (0.4%) recovered to date
- Heavy Oil Fields are within the existing oil fields



Heavy Oil Challenges

Heavy oil will always be disadvantaged relative to light oil on the basis of development cost and commodity price



PROPERTIES

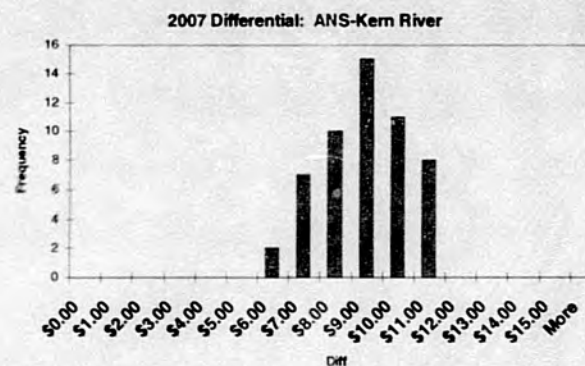
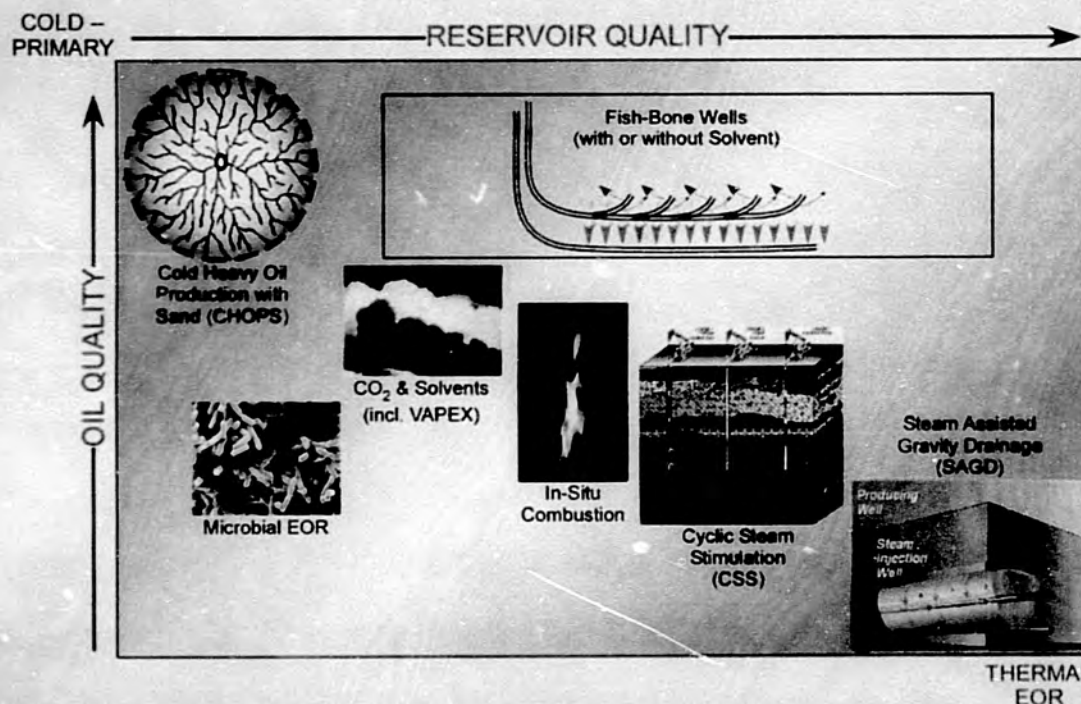
- Chemical
 - Hydrogen depleted relative to light oil
- Physical
 - High viscosity

BUSINESS IMPACT

- Retool refineries
- Take a lower price on market
- High well density
- Add heat to reservoir & transit lines
- Add diluent to major pipelines
- Upgrading (partial refining)
- Environmental Mitigation (e.g. CO₂ sequestration)
- Water treatment
- Sand Disposal
- Wellwork

Revenue

Costs

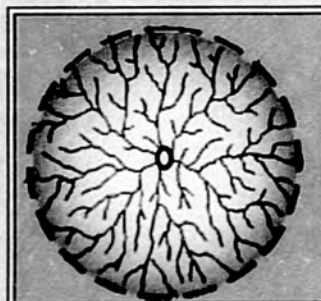


CHOPS

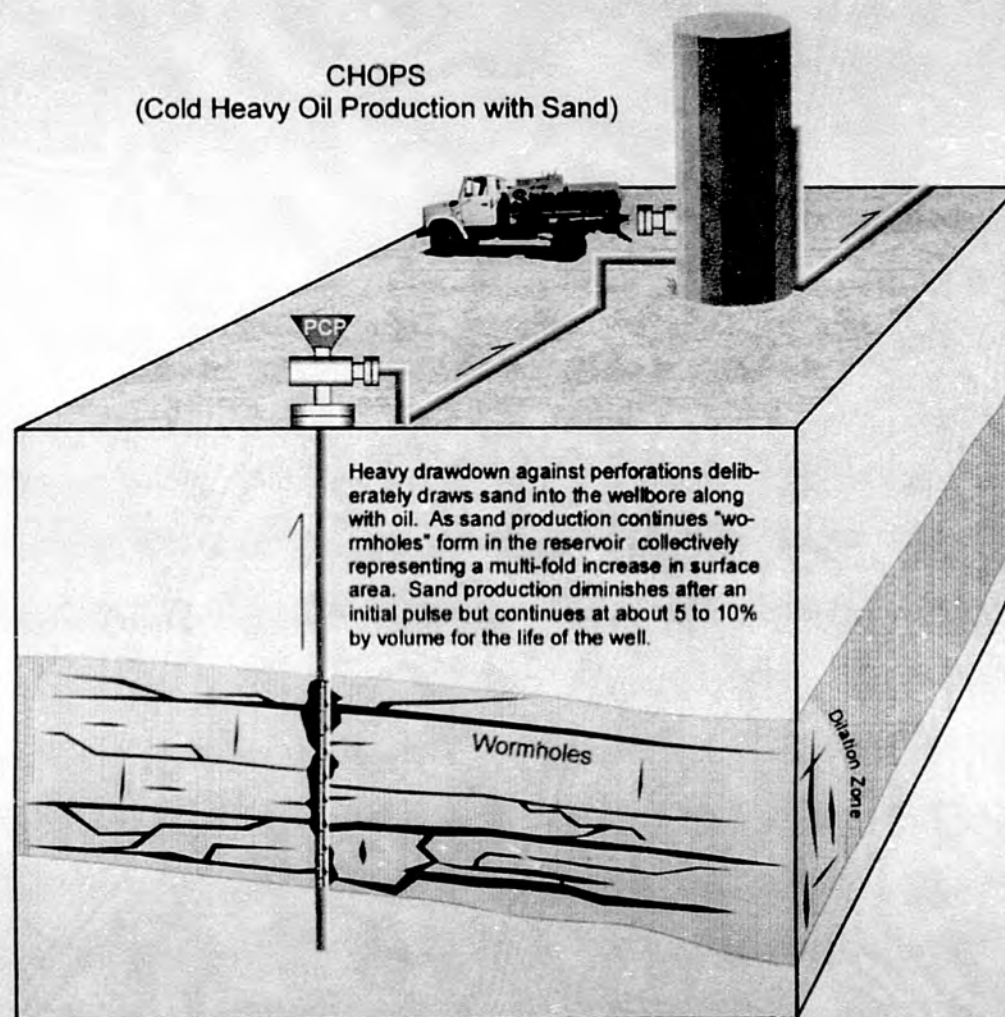
Cold Heavy Oil Production with Sand



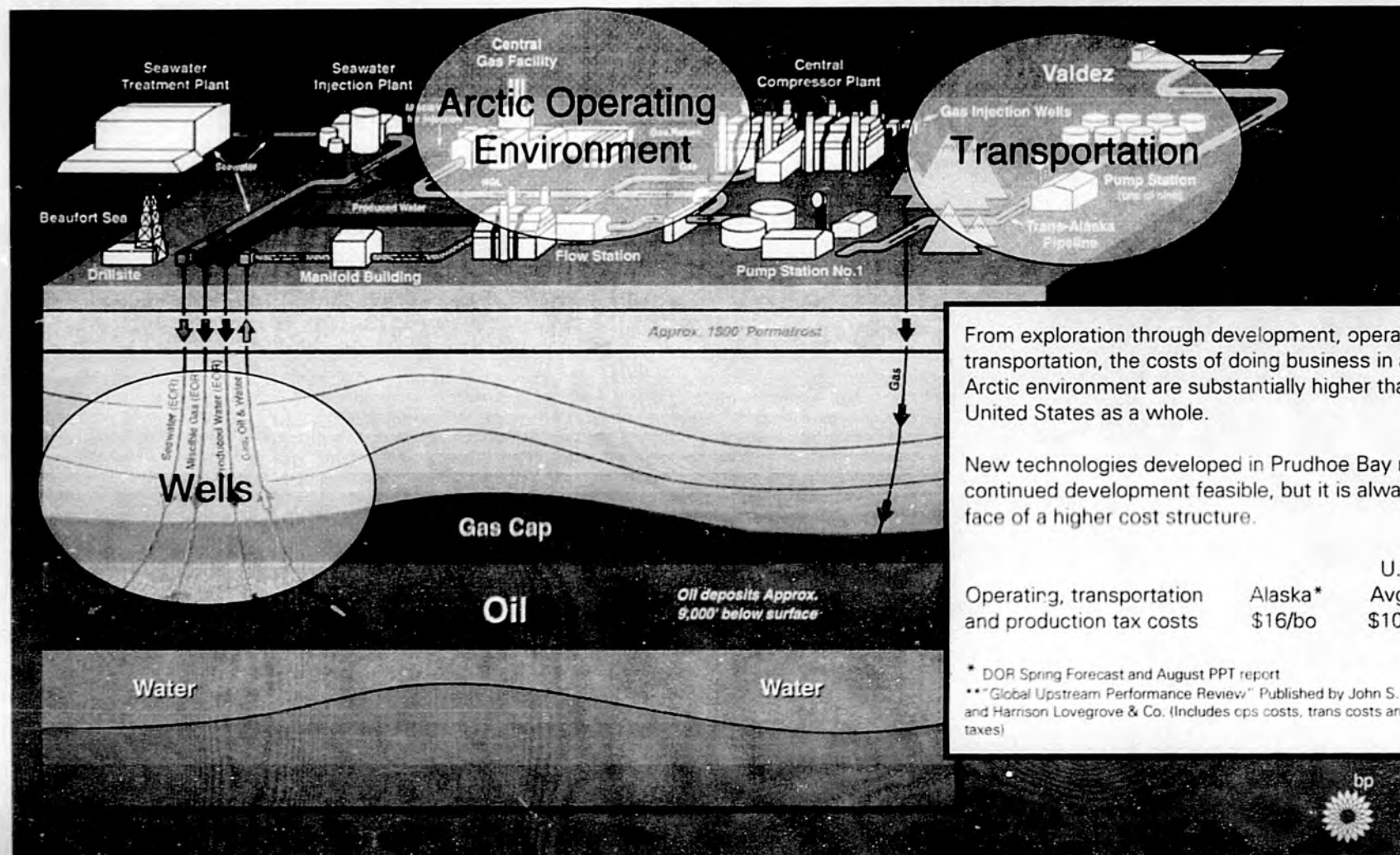
Vertical View of Reservoir



CHOPS (Cold Heavy Oil Production with Sand)



Alaska vs. Average U.S. Cost Structure



From exploration through development, operating and transportation, the costs of doing business in a remote Arctic environment are substantially higher than the United States as a whole.

New technologies developed in Prudhoe Bay make continued development feasible, but it is always in the face of a higher cost structure.

	Alaska*	U.S. Avg**
Operating, transportation and production tax costs	\$16/bo	\$10/bo

* DOR Spring Forecast and August PPT report

** "Global Upstream Performance Review" Published by John S. Herold, Inc. and Harrison Lovegrove & Co. (Includes ops costs, trans costs and production taxes)



Prudhoe Bay Development Summary

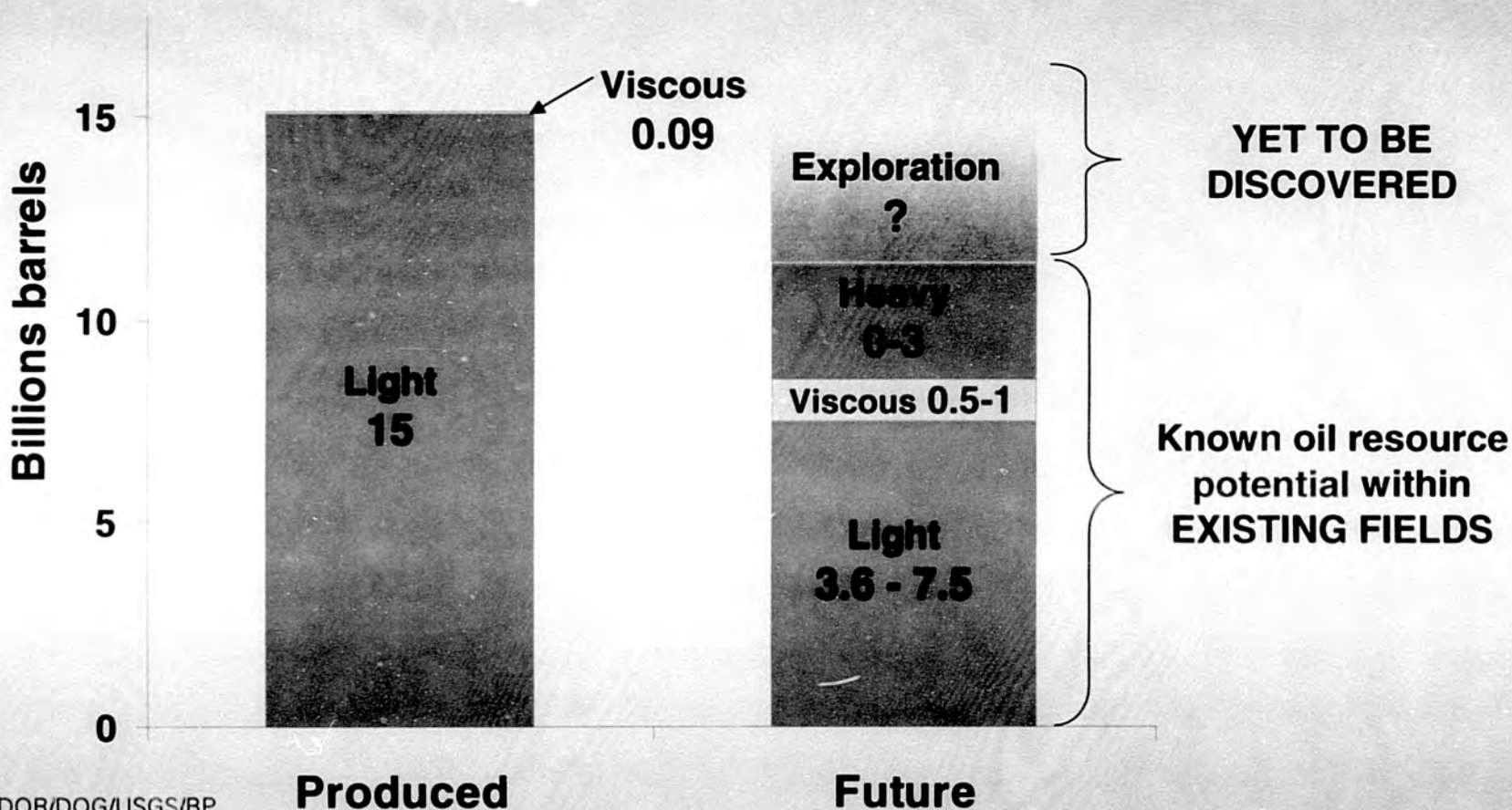


- Technology is Critical to Optimize Recovery:
 - Developing and applying new technology at scale
 - Arctic Technology
 - Major Facility Projects
 - Advanced Reservoir Processes Technology
 - Drilling/Workover Technology
- Development has been extensive and very successful
- Oil production is mature with over 11 billion barrels recovered
 - 1200 active wells
 - Declining oil rate and increasing water and gas rates
- Ongoing Projects Are Needed to Offset Steep Natural Decline
- Prudhoe Bay has a large part of Alaska's Future Opportunities

The future of North Slope oil still tied to existing fields



Sustained investment in light oil development is critical to developing heavy oil and new fields

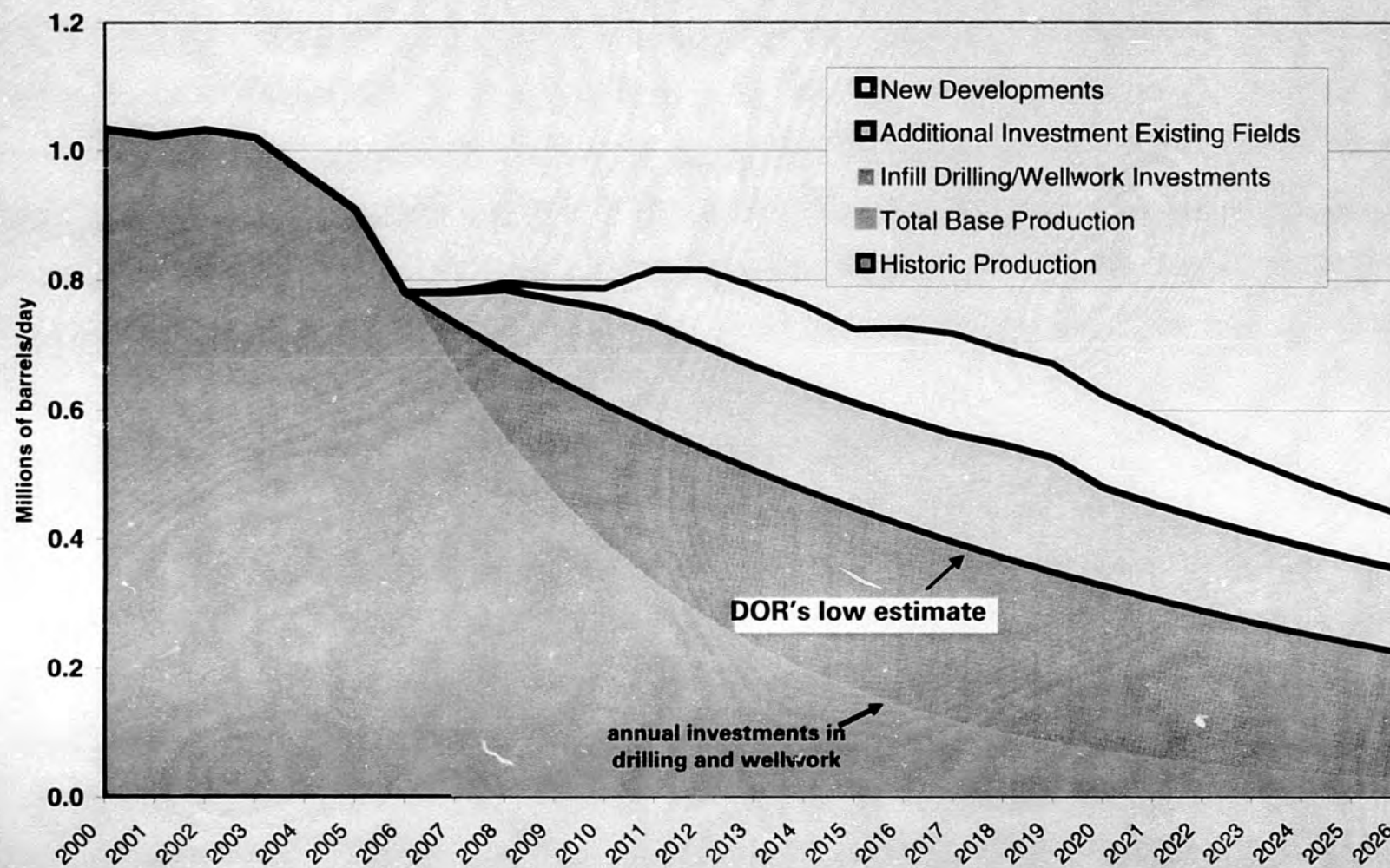


Source: DOR/DOG/USGS/BP

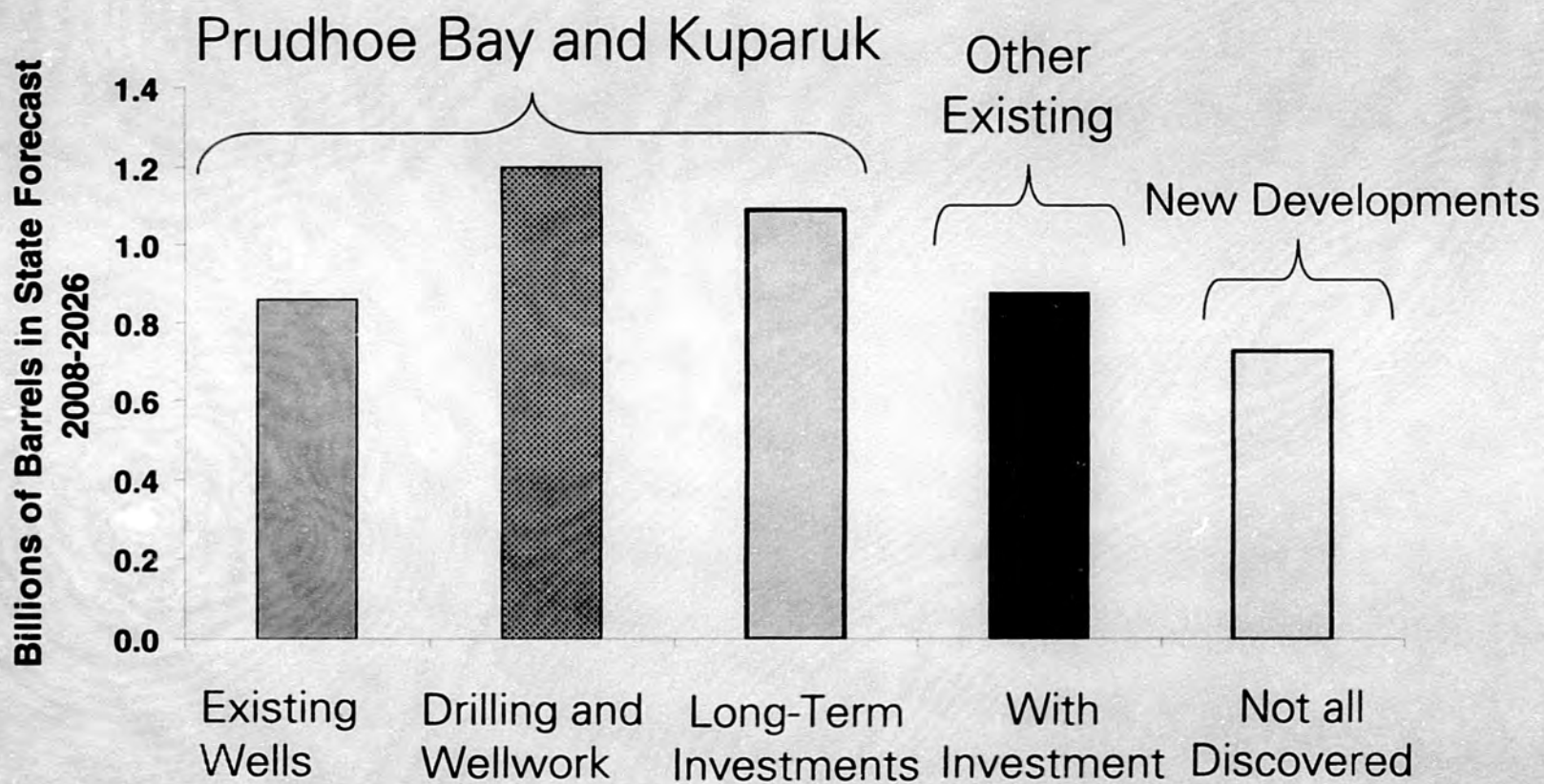
Future of oil production is critically dependent on existing large fields, additional investments



DOR Production History and Forecast



Alaska needs a world scale level of ALL types of investment to sustain the future of oil production



State Revenue, \$billion*

13

18

16

11

9

*assuming PPT terms and state revenue of \$15/bbl at \$60/bbl ANS

Sector inflation triggered by high oil prices is real and substantial – example measures



"The Upstream Capital Costs Index, developed by Cambridge Energy Research Associates (CERA), shows that costs for oil and gas production equipment, facilities, construction, materials and personnel have increased 53% since 2005." (Source: PPT Implementation Status Report, August 2007)

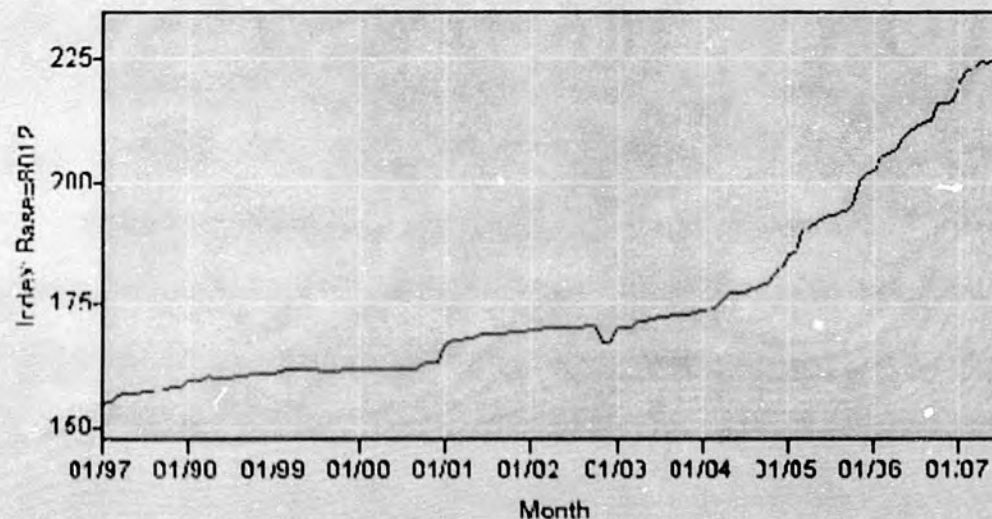
2004-2006 U.S. Average Cost Increases per barrel

- 153% on Finding and Development costs (Capital)
- 58% Lifting costs (Expense)

(Source: "Global Upstream Performance Review" published by: John S. Herold /Harrison Lovegrove)

Oil and Gas Field Machinery and Equipment PPI

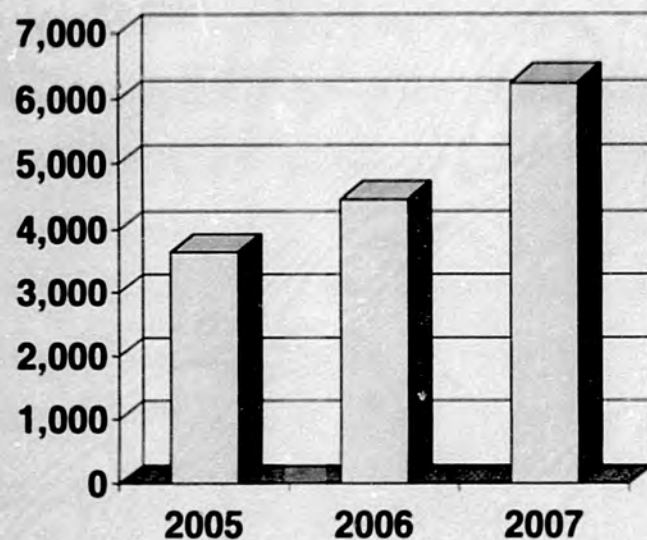
Source: U.S. Department of Labor



Investment activity is also causing a large part of the increase



□ North Slope Contractor Jobs



- Since late 2004, BPXA staff has grown from 1300 to approaching 2000 employees
- Active drilling rig count in BP's producing fields has gone from 9 in 2004 to 10 in 2007
- BP commissioned a new camp this summer and rented 4 more, increasing our camp capacity by 30%
- Seismic acquisition activity brought in additional 100+ contractors to the Slope for the winter season
- Pickup truck rentals in support of NS operations has gone up approximately 60%
- Preventative maintenance and inspection programs on the 30-year old infrastructure are at an all-time high

Economic impact of proposed bill on new investments



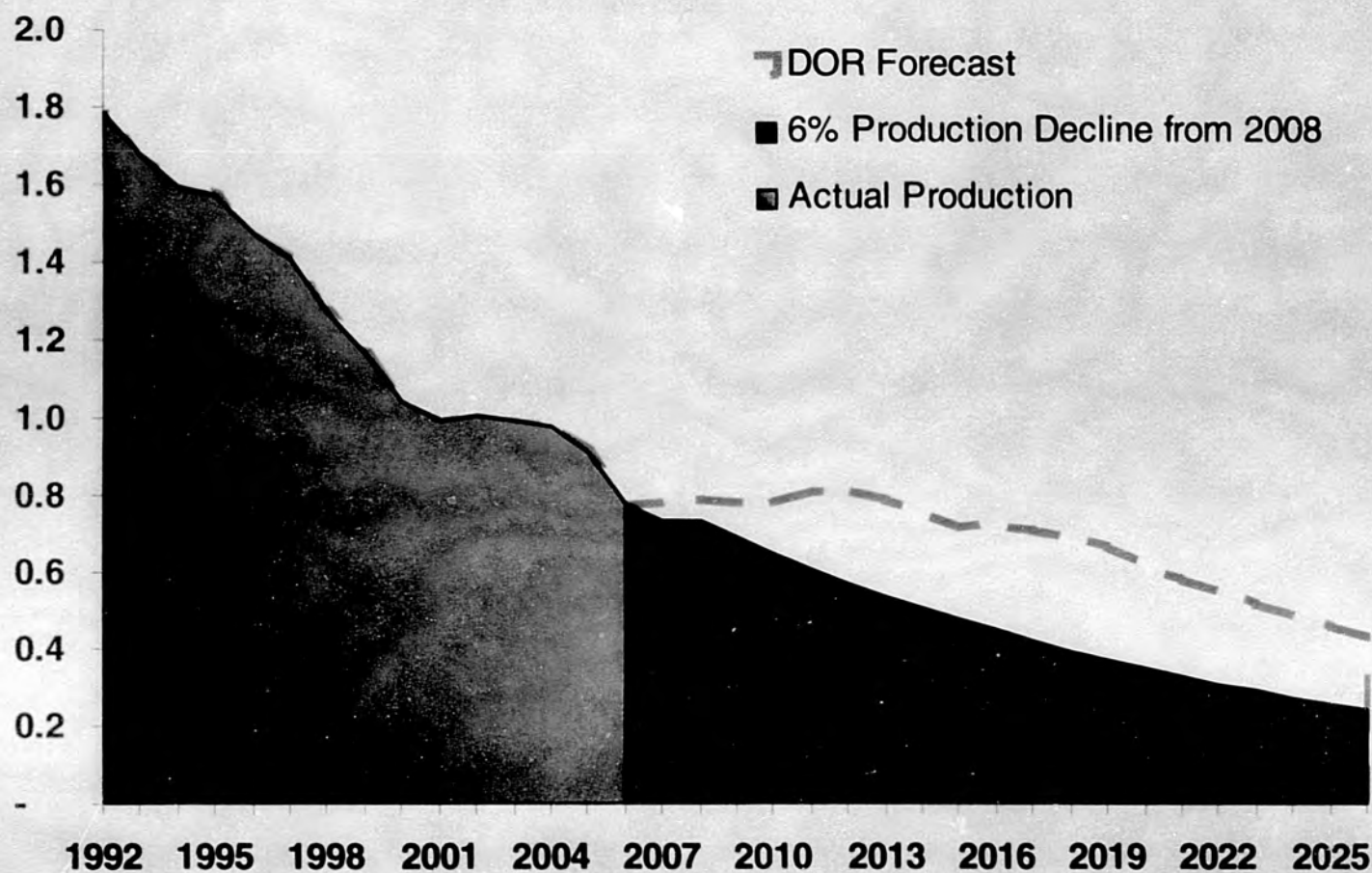
- About 70% of future investment decisions are within Prudhoe Bay and Kuparuk
- Minimum tax imposed on these fields causes a progressive deterioration of economics at medium to low prices
- A significant number of investment opportunities in Prudhoe Bay and Kuparuk will cross into marginal or non-economic territory, raising costs and lowering netbacks for the rest of the North slope production.

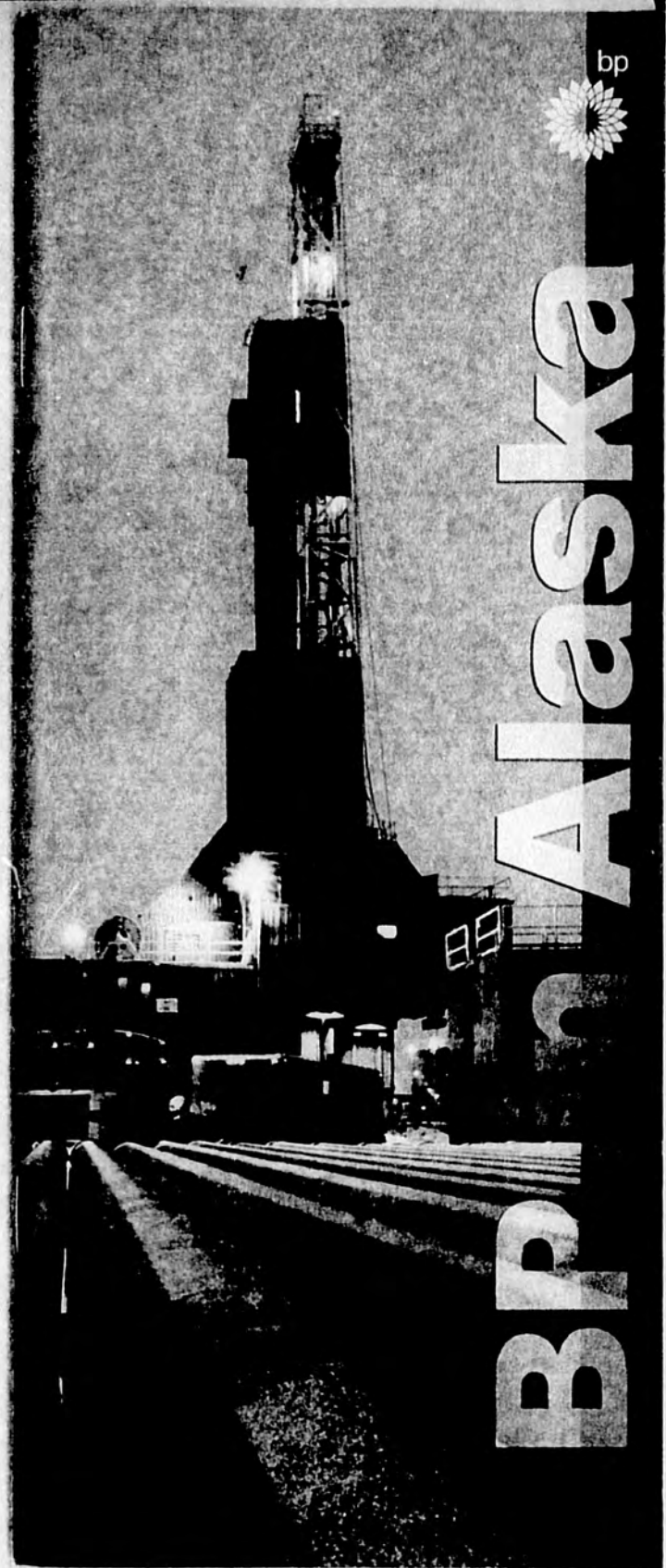
Key Messages



- Production, not tax rate, is the major factor in determining state revenue for the future years
- Delivering the production forecast will require tens of billions of investment
- Investment decisions are made on the basis of strategy, resources, technology, economics, and risk, including fiscal stability
- SB/HB2001 significantly deteriorates economics on 70% of investment options in the next 20 years
- Higher prices and developing technology could give the Alaska fields a new lease on life, but huge investments are needed
- The focus of the tax policy should be on encouraging large investments in existing fields as well as exploration
- The proposed bill creates **uncertainty** for taxpayers and potentially distorts business decision making

The time to influence the future outcome for the state is now





BP Alaska



bp

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BP is pleased to present this publication of "BP in Alaska" fact book printed September 2007. Sources for this book include the State of Alaska AOGCC, DNR and DOR annual reports. For more information go to <http://alaska.bp.com>

About us

BP Exploration (Alaska) Inc. opened its first office in Alaska in 1959 and today operates 13 North Slope oil fields and four North Slope pipelines. It also owns a significant interest in six other producing fields along with the Trans Alaska Pipeline System (TAPS).

BP Alaska is an upstream business unit of the BP Group, ranked globally as the third largest oil company and one of the 10 largest corporations.

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 the United States, and in BP's global portfolio.

2006 Statistics

Employees

1,650
(82% Alaska residents)

Capital investment

\$571 million

Operating budget

\$1.1 billion

State and local taxes and royalties

\$1.85 billion
(annual estimate with current tax rates)

Net production rate

235,700 barrels of oil equivalent per day

Community investment

\$10.2 million

BP's midtown Alaska headquarters building.

President's message



Doug Suttles

Alaska and BP have a shared history that dates back nearly 50 years. BP is proud of its history in Alaska, but we're also focused on growing our business and creating opportunities for the future.

To make that future happen, we're focusing our resources on several key areas: the renewal of our North Slope infrastructure and renewal of our workforce, the advancement of technology to develop the known resources, and moving forward with an Alaska gas pipeline.

BP was part of Prudhoe Bay at the field's start up, and in June 2007 Prudhoe Bay celebrated its 30th anniversary. The renewal of Prudhoe Bay's infrastructure has taken on a new focus since the events of 2006. BP has invested time, money and people in the renewal of Prudhoe Bay's cross-country pipelines, related facilities, safety systems and other infrastructure.

In addition, we're focused on renewing our workforce and hiring Alaskans. More than 3,000 people were working on BP projects on the North Slope at the peak of operations in the winter of 2006-07. BP also supports many educational and vocational training programs in Alaska.

The development and leveraging of technology is also important to BP's Alaska strategy. BP has focused on exploring for the known resources such as heavy oil, technically challenging fields and ultimately the development of an Alaska natural gas pipeline.

The principle of leveraging technology to extend the life of Alaska's North Slope to get more resources out of the ground has been successful over time. At first, Prudhoe Bay was expected to produce little more than 9 billion barrels of oil, and three decades later the field has produced more than 11 billion barrels.

BP has drilled one of the longest ultra extended reach wells in the world. We hope to capitalize on that technological edge to develop the offshore Liberty oil field. Liberty is one of the largest undeveloped fields on the North Slope with approximately 100 million barrels of oil. If we're successful, it would set new marks for the longest extended reach wells, stepping out nearly eight miles.

The development and leveraging of new technology will also be essential to meet the challenges of the enormous heavy oil resource, which lies just below the permafrost. There is an estimated 20 billion barrels of heavy oil in place, but so far there has been no heavy oil production in Alaska. The challenges are huge. This oil has the consistency of thick, cold molasses. Yet, we know that heavy oil development will be important to sustaining North Slope oil production far into the future.

The development of a gas pipeline is important to Alaska, to BP and to the rest of the country. Alaska's North Slope gas represents the largest, known, undeveloped gas resource in the United States, and in BP's global portfolio. BP believes that a gas pipeline is not only essential, but it helps build our 50-year future in Alaska. Projects like Liberty and heavy oil, combined with the development of Alaska North Slope gas, will extend the life of the existing North Slope oil fields for decades.

Thank you,
Doug Suttles
President
BP (Alaska) Inc.

<http://alaska.bp.com/>

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, but our investments extend beyond our business to the communities where we operate and where our employees and their families live. BP believes it can best support communities by helping to build skills and leadership, growing community capacity, and helping to bring about measurable and long-term community improvement.

In 2006, BP contributed \$10.2 million to support more than 200 nonprofit and educational organizations and programs in Alaska. In accordance with our Charter agreement with the State of Alaska, 30 percent - or around \$3.1 million - was contributed to the University of Alaska Foundation. This commitment carries no restriction in terms of use of the funds, but is intended to support the university in its goal of helping Alaska develop a more diversified, sustainable and self-sufficient economy.

BP supports many educational and workforce development programs, and provides 25 four-year scholarships each year to graduating high school seniors statewide. BP also recognizes 30 outstanding educators through the annual Teachers of Excellence program.



BP contributed \$10.2 million to more than 200 nonprofits in 2006.

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 employees contributed \$500,000 and countless volunteer hours in 2006.

BP's employees in Alaska contributed more than \$500,000 to United Way and other community and education organizations in 2006. They also contributed thousands of volunteer hours to lead organizations, building houses, cleaning up communities, developing parks, coaching and mentoring kids, helping in classrooms, serving meals to the hungry and raising funds to educate people about serious health issues. The company matches employee donations, volunteer hours and fundraising efforts.



BP's innovative Energy Center opened in 2002.

BP Energy Center

The BP Energy Center was built to support the community. It is a training, meeting and conference center for nonprofits and education organizations from throughout Alaska. A large multi-purpose room and five smaller meeting rooms are available without charge to eligible organizations.

1973 Congress approves the Trans Alaska Pipeline Authorization Act.

1974 Trans Alaska Pipeline construction begins.

Exploring through technology

BP is exploring technologies that go beyond 3-D seismic, to even more innovative drilling techniques, to using carbon dioxide, thermal, low salinity flooding, even bacteria, all to unlock more barrels on Alaska's North Slope.

Investing in Alaska...

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 and the foundation for a lasting partnership between BP and Alaskans. Since the start up of Prudhoe Bay production, we have invested more than \$22 billion of capital in Alaska and paid \$32 billion in state taxes.

Today...

BP changed its focus several years ago from expensive, wildcat exploration to concentrate on exploring new ways to develop the vast North Slope resources that have already been discovered, but have yet to be fully developed. It's been a good decision and we've had success adding production from viscous oil and smaller, technically challenging fields. Today viscous oil production on the North Slope is about 40,000 barrels per day gross. In 2006, BP's net viscous oil production was 20,000 barrels per day. This production came from the West Sak and Tabasco Kuparuk satellites; the Prudhoe satellite fields of Polaris and Orion, and the Milne Point field.



BP's HIVE (Highly Immersive Visualization Environments) is a workroom with a series of three-dimensional computer screens around which large teams of people can gather to manipulate data and pictures.

1977

Prudhoe Bay field begins production.

1981

Kuparuk field begins production.

1986

Lisburne field begins production.

Tomorrow...

Unlocking heavy oil

The North Slope holds more than 20 billion barrels of heavy oil. This resource represents one of the largest development opportunities for Alaska. However, today there is no commercial production of heavy oil.

Heavy oil is colder and thicker than the viscous oil, though it is found in the same formations. The oil is like cold, thick molasses and the formations are relatively shallow, close to the permafrost and are comprised of unconsolidated rock. These factors all make it very difficult and currently uneconomic to produce.

BP estimates that with advances in technology, approximately 2 billion barrels of heavy oil could be produced from the Schrader Bluff/West Sak and Ugnu reservoirs. A new heavy oil technical team is working to evaluate and assess multiple heavy oil technology options such as: CHOPS (Cold Heavy Oil Production with Sand), steam injection and solvent injection. These technologies are used in Venezuela and Canada.

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 gas hydrates, a potential long-term global, unconventional gas energy resource. 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, unconventional gas resource target.

The project recorded a number of firsts, including the first significant gas hydrate-bearing core samples in Alaska and the first delineation of a seismically-defined gas hydrate prospect in Alaska. Known deposits of methane hydrate in Alaska and other parts of the world are enormous but the challenge is to separate the natural gas from the solid gas-water-ice in which it occurs. Once the data from the test well is evaluated, it will be shared with industry technical experts. BP and DOE will determine the next step.

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

Ultra extended reach drilling (UERD) is key to developing Liberty, a 100-million-barrel field that lies offshore in the Beaufort Sea. Advances in drilling technology now make it possible to develop the field from the existing Endicott satellite drilling island. The wells would reach up to eight miles, one of the longest ever drilled, and would require a sophisticated drilling rig that has yet to be built.

UERD 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. This technology has enabled BP and the other North Slope producers to tap into the massive viscous oil assets.

Here are a few more examples:

Horizontal drilling 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 of yesteryear might expose 200-300 feet of rock while the new wells can expose more than 20,000 feet.

Multilateral wells are multiple wells drilled off a common hole to the surface. BP drilled Alaska's first five-legged well in 2005 into the viscous oil Polaris reservoir. Multilateral wells are key to increasing viscous oil production.

Extended reach drilling uses downhole directional equipment and drilling motors to reach formations miles from the drilling rig. It reduces cost, lowers environmental risk and shrinks the size of an operation's footprint by using land-based drilling in fields that normally would require costly offshore operations.

10
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.

Moving oil and gas

Marine transportation

Four new 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. They are the largest double-hulled tankers ever built in the U.S.

The four new ships represent an investment of more than \$1 billion, the single-largest commercial shipbuilding project in U.S. history. These ships joined the existing double-hulled Prince William Sound in the regular Alaska trade.

National Steel & Shipbuilding Co. built the new 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 oil leaks to the environment.

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



The Alaska Tanker Co.

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

Both the states of Alaska and Washington have recognized ATC for its outstanding safety and environmental performance, and in 2004 ATC received the U.S. Coast Guard's prestigious Benkert Osprey environmental award for achievements in protecting the marine environment.

A completely double-hulled fleet

Tanker Name	Capacity in Barrels
Alaskan Legend	1,300,000 bbls
Alaskan Explorer	1,300,000 bbls
Alaskan Frontier	1,300,000 bbls
Alaskan Navigator	1,300,000 bbls
Prince William Sound	800,000 bbls

www.aktanker.com

12

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.

2002

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

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 Prudhoe Bay on Alaska's North Slope to Valdez, the northernmost ice-free port in North America.

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%

www.alyeska-pipe.com



14

2002

State of Alaska renews TAPS right-of-way for 30 years more.

2003

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

TAPS FACTS

Length of TAPS

800 miles
(Pump Station 1 to Valdez)

Crosses

3 mountain ranges, > 800 rivers, streams

Pipeline diameter

48 inches

Total cumulative throughput (2006)

15.3 billion barrels of oil equivalent
(Pump Station #1)

Reliability factor (2006)

99.65%

TAPS throughput (2006)

759,081 average barrels/day

Cumulative barrels (2006)

277,064,405 barrels/year

Construction cost

> \$8 billion in 1977

Valdez Marine Terminal

Storage capacity

9.18 million barrels

Tankers loaded (2006)

18,276

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 System and 100% of the Badami Pipeline System.

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.



Greater Prudhoe Bay

After 30 years of production, Prudhoe Bay remains the largest oil field in North America and ranks among the 20 largest fields ever discovered worldwide. Of the 25 billion barrels of original oil in place, approximately 13 billion barrels can be recovered with current technology. Today the field has produced 11 billion barrels. BP's net cumulative production from Prudhoe Bay is approximately 4.42 billion barrels of oil equivalent (BOE).

Production from the Prudhoe Bay field initial producing area averaged approximately 303,000 BOE per day in 2006. The field also contains an estimated 26 trillion cubic feet of natural gas resource (in place) 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 was 500 feet thick in some areas.

The Greater Prudhoe Bay Area, which includes Prudhoe Bay, the Prudhoe Bay satellite fields and the Greater Point McIntyre Area fields, in total produce about 380,000 BOE per day. BP's net production from Greater Prudhoe Bay Area is approximately 100,000 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 small accumulations of oil that can often be developed using existing infrastructure. The average daily production from Prudhoe Bay satellites is about 40,800 barrels of oil equivalent per day. BP's net share of that production is about 9,400 barrels. There are about five



satellite fields currently producing and the liquids are processed through the field's main facilities. Aurora and Borealis produce from similar formations. Midnight Sun produces from a sandstone formation at 8,000 feet below sea level.

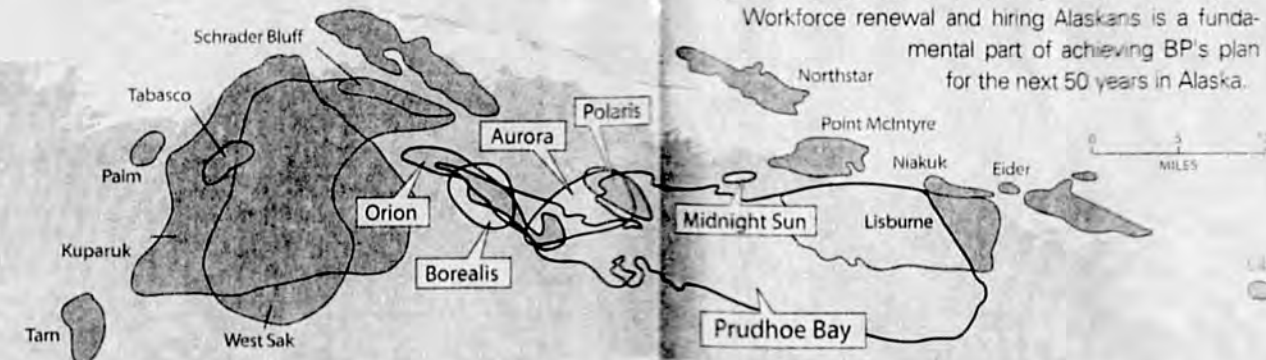
Orion and Polaris satellite fields both produce the difficult viscous oil from the Schrader Bluff formation, at depths of 4,000 to 5,000 feet below sea level. By using advanced drilling technologies we are growing this important resource.

The Prudhoe Bay satellite fields have produced more than 100 million barrels of oil equivalent. BP's net cumulative production from is approximately 23 million barrels of oil equivalent.

Prudhoe Bay renewal

Prudhoe Bay's anniversary milestone and the events of 2006 have placed a new emphasis on renewing the field's infrastructure and workforce. Nearly 700 Alaskans worked on the new Prudhoe Bay transit pipeline system installation in the winter of 2006-07. The project includes the installation of 16 miles of cross-country pipeline, pigging modules, corrosion-inhibitor injection facilities, state-of-the-art leak detection, metering facilities and all the affiliated electrical and emergency systems. The result will be an upgrade of the field's oil transit line system and related infrastructure by year end 2008.

We also support educational and technical training programs aimed at preparing Alaskans for jobs. Workforce renewal and hiring Alaskans is a fundamental part of achieving BP's plan for the next 50 years in Alaska.



2004
16
Operations Support Center brings smart board technology to enhance Slope operations.

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

2005
North Slope production exceeds 15 billion barrels of oil. Alyeska Pipeline Service Co. begins major upgrade to extend life and improve efficiency of Trans Alaska Pipeline System.

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 <i>(includes satellite fields)</i>	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	47 trillion SCF	0.1 trillion SCF	0.1 trillion SCF
Current Rates (12/31/06)	Gross Field	Gross Field	Gross Field
Oil (thousands BOE/day)	285.7	5.0	13.2
Gas (millions SCF/day)	7,990		
Water (thousands bbl/day)	914.3		
Number of Wells (12/31/06)			
Oil Producers	842	2	15
Gas Injection	31	0	0
Water Injection	162	3	2
WAG Injection	38	0	8

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	7,757 acres
Original Oil in Place	270 billion barrels ¹		
Current Rates (12/31/06)	Gross Field	Gross Field	Gross Field
Oil (thousands BOE/day)	10.3	2.8	17.2
Number of Wells (12/31/06)			
Oil Producers	8	7	27
Gas Injection	0	0	0
Water Injection	17	5	10
WAG Injection**	1	1	7

Source: State of Alaska Oil and Gas Conservation Commission.

**Water Alternating Gas Injectors.

Alaska gas

Alaska's North Slope natural gas is the largest undeveloped resources in BP's global portfolio, and bringing it to market is critical to BP's plans for the next 50 years. There are more than 35 trillion cubic feet of known gas resources on the North Slope and the company expects 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.

Hard at work producing more oil

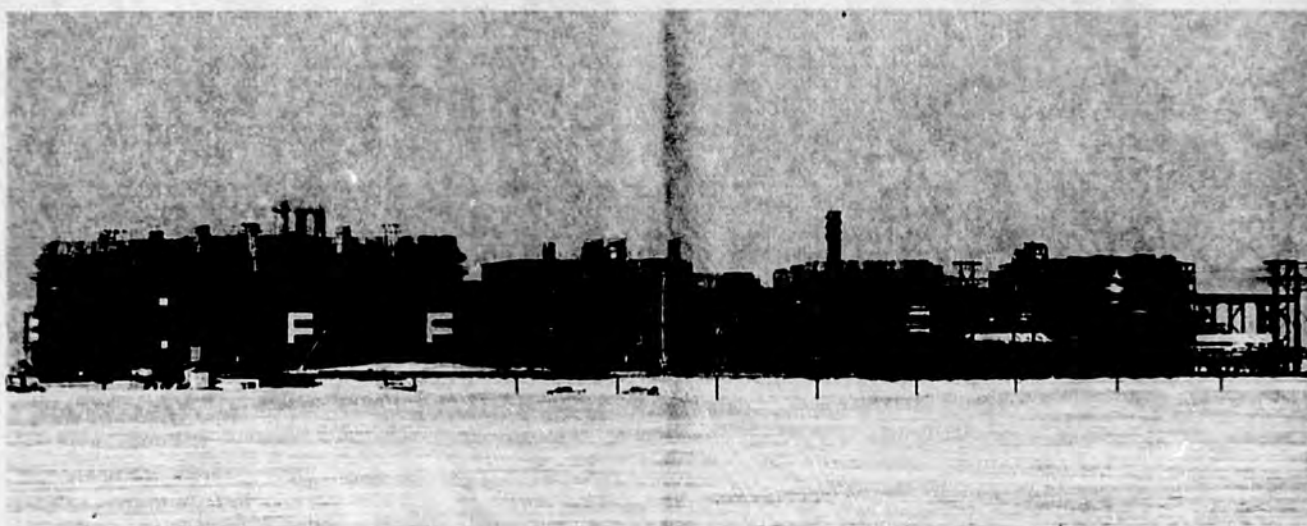
Through the years when a gas pipeline was not economic, North Slope gas has been injected back into the ground to maintain reservoir pressure and produce more oil. Alaska will recover an additional 3 billion barrels of oil thanks to this gas recycling over the last 30 years. The best part of this story is that the same gas that was reinjected to produce more oil will be used again in the gas pipeline. If gas had been commercialized earlier, we would have produced much less oil and suffered losses on the sale of gas.

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 extend the life of the North Slope oil fields for decades. In addition, commercializing the gas will provide additional state and local revenues, along with jobs for Alaskans and opportunities for Alaska businesses.

BP and the Slope's other large producers, ConocoPhillips and ExxonMobil, have invested hundreds of millions of dollars to evaluate many options to commercialize North Slope gas. These include liquefied natural gas and gas-to-liquids. These evaluations show that a gas pipeline that delivers gas to the North American market is the most promising option, and the one that delivers the greatest benefits to the State of Alaska.

There are many risks associated with a project of this size, beginning with its projected cost in the neighborhood of \$30 billion. These risks include: construction cost overruns, changing gas prices, and changes to regulatory rules.

The Alaska gas line will be one of the largest and most complicated projects in the world. Building it requires the right team, and BP hopes to be part of that team.



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

20
2006

Fourth Alaska
Class tanker
delivered.

Alaska adopts
major rewrite of
oil taxes.

BP closes half of Prudhoe Bay
after finding corrosion
problems in transit lines.

BP commits to rebuilding 16 miles of transit lines to
support another 50 years of oil production.

Greater Point McIntyre

The Greater Point McIntyre Area encompasses Pt. McIntyre field and the nearby satellite fields of West Beach, North Prudhoe Bay, Niakuk and Western Niakuk. The Lisburne Production Center processes fluids from Pt. McIntyre area fields and the Lisburne field. Cumulative production from the Greater Point McIntyre area is 738 million barrels of oil equivalent. BP's cumulative net production is approximately 140 million barrels of oil equivalent.

Point McIntyre

Located 7 miles north of Prudhoe Bay, the Point McIntyre field was discovered in 1988 and came on-line in 1993. Pt. McIntyre contains 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 21,000 barrels per day in 2006.

BP produces the field from two drill site gravel pads. Production rates are maintained through drilling of new wells, enhanced oil recovery methods and facilities upgrades. Part of Point McIntyre production is processed at Prudhoe Bay Gathering Center #1 to more efficiently handle the water and to increase the water available for water flooding.

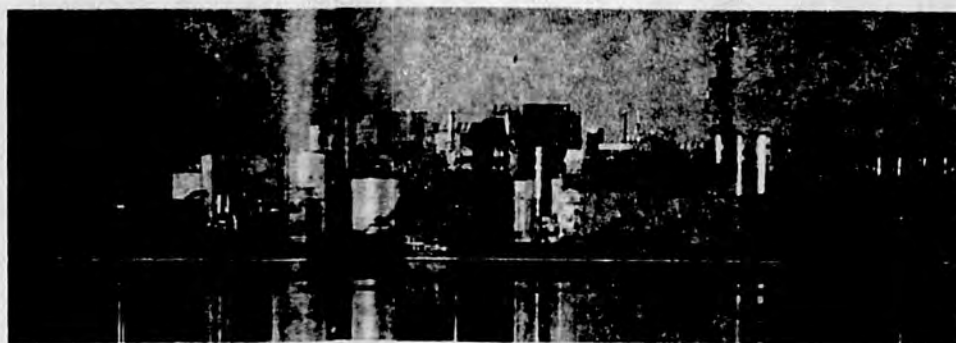
Niakuk and Western Niakuk

The Niakuk fields lie offshore and contain about 300 million barrels of oil in place. Production in 2006 averaged about 4,700 barrels per day from the lower Cretaceous Kuparuk River formation, a structurally and stratigraphically complex formation. A 2004 well set a world record length for coiled tubing drilling of 17,515 feet.

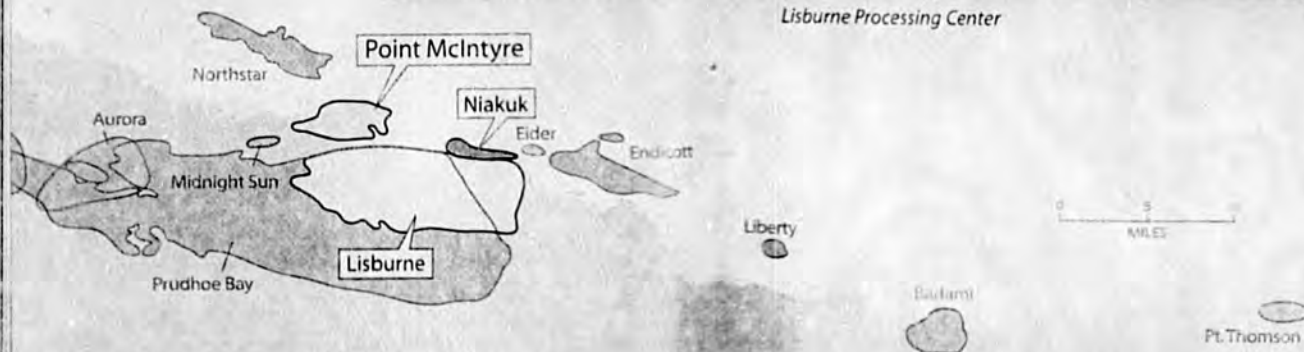
Lisburne

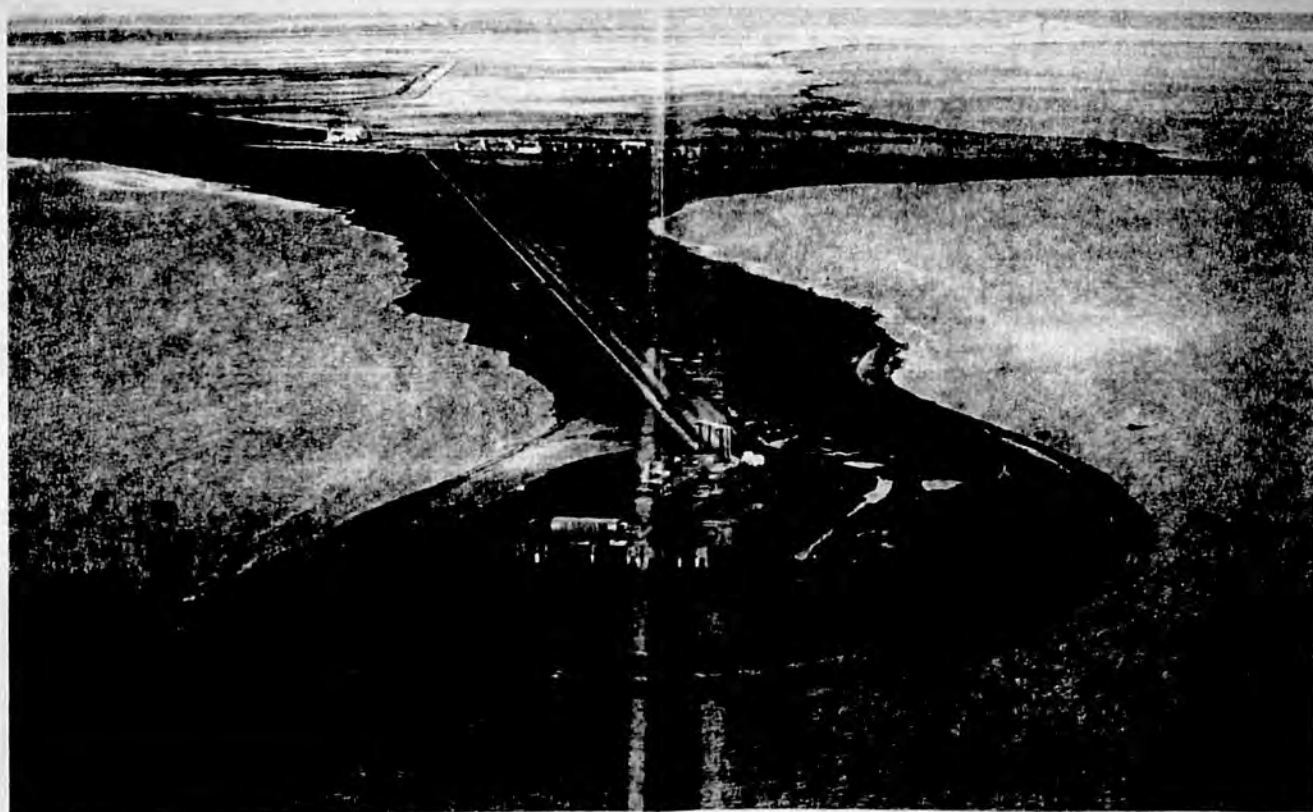
The Lisburne field is a complex, fractured carbonate reservoir that lies underneath and adjacent to the main Ivishak reservoir at Prudhoe Bay. The field was discovered in 1968 along with the Prudhoe Bay field and came on-stream in late 1986. The field contains an estimated 1.8 billion barrels of oil in place. Production averaged about 10,700 barrels per day in 2006. Cumulative production from the Lisburne field is nearly 162 million barrels of oil equivalent. BP's cumulative net production from the field is approximately 3 million barrels of oil equivalent.

Horizontal drilling technology using coiled drilling techniques, along with geoscience techniques to identify fracture and fault locations, have increased production rates in recent years.



Lisburne Processing Center





The Niakuk and Western Niakuk fields lie offshore of the Prudhoe Bay shoreline.

Oil Fields	Point McIntyre	Niakuk	Lisburne
Owners	BP (Operator) ~26% ConocoPhillips ~36% ExxonMobil ~36% Others ~2%	BP (Operator) ~26% ConocoPhillips ~36% ExxonMobil ~36% Others ~2%	BP (Operator) ~26% ConocoPhillips ~36% ExxonMobil ~36% Others ~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
Current Rates (12/31/06)	Gross Field	Gross Field	Gross Field
Oil (thousands BOE/day)	36.6	4.7	10.7
Number of Wells (12/31/06)			
Oil Producers	53	15	45
Gas Injection	1	0	3
Water Injection	7	7	0
WAG Injection**	7	0	0

Source: State of Alaska Oil and Gas Conservation Commission.

** Water Alternating Gas Injectors.

Milne Point Unit

Milne Point - Kuparuk - Schrader Bluff*

Located about 25 miles west of Prudhoe Bay, Milne Point has become an innovator in the application of new reservoir technology to enhance oil recovery. Today it produces about 36,000 barrels of oil equivalent per day (BOED). BP's net production is 31,000 BOED. Cumulative oil production at Milne Point is 248 million BOE, BP's net production 176 million BOE. Milne was discovered in 1969 by Conoco and began production in November 1985. BP became operator in 1994 and it purchased 100 percent of Milne in 2000.

Milne produces from three main reservoirs. The Kuparuk and the Sag River reservoirs, are lighter oil horizons and the Schrader Bluff produces a more viscous oil. BP has been a leader in the development of the viscous oil resource using horizontal multilateral drilling. Viscous oil is colder and thicker than other North Slope oil, and is the consistency of syrup. All production fluids are processed through the Milne Point Unit production facilities, which are being upgraded to handle the colder crude oils.

Even more challenging is the heavy oil resource. There is an estimated 20 billion barrels of oil in place on the North Slope. BP is testing new technology at Milne Point to pioneer heavy oil development. Heavy oil has a consistency similar to cold molasses, thick and sticky, and is currently uneconomic to produce with existing technologies on the North Slope. BP has a heavy oil technical team in place that is evaluating and assessing heavy oil technology options. Milne's rocks and fluids lend themselves better to cold recovery techniques, including CHOPS (cold heavy oil production with sand).

BP estimates that with advances in technology, about 2 billion barrels of heavy oil could be produced from the Schrader Bluff/West Sak and Ugnu reservoirs.

* Milne-Kuparuk is a separate and distinct unit from the large Kuparuk River Field, but produces from some of the same reservoir sands.



Milne uses new reservoir technology to enhance oil recovery.

Oil Fields		Milne Point-Kuparuk-Schrader Bluff *	
Owners		BP (Operator)	99.4%
		Anadarko	.6%
Field Data			
Participating Field Area		49,668 acres	
Original Oil in Place (gross)		0.92 billion barrels	
Cumulative Oil Production		Gross Field	
Production 12/31/06 (millions of barrels of oil equivalent)		248	
Current Rates (12/31/06)		Gross Field	
Oil (thousands BOE/day)		32.2	
Gas (millions SCF/day)		19.8	
Water (thousands bbl/day)		62	
Number of Wells (12/31/06)			
Oil Producers		121	
Gas Injection		2	
Water Injection		66	
WAG Injection**		32	

Source: State of Alaska Oil and Gas Conservation Commission.

** Water Alternating Gas Injectors.





The Kuperuk field is the second largest producing oil field in North America.

Greater Kuperuk Area

The Kuperuk field is the second largest field in North America and produced its 2 billionth barrel in July 2005. Discovered in 1969, Kuperuk 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 Kuperuk sands at depths of 5,500 to 6,500 feet. Kuperuk produced about 121,000 barrels of oil equivalent per day (BOED) in 2006.

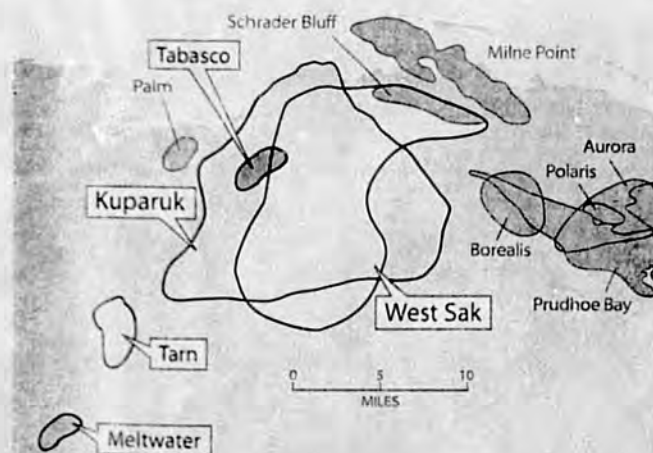
BP holds major ownership in the Greater Kuperuk Area, which includes the satellite fields of Tarn, Tabasco, Meltwater and West Sak. ConocoPhillips is the field operator. The production from these fields is processed through the Kuperuk production facilities. Processed oil from Kuperuk is piped 26 miles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

Kuperuk satellite fields

Tabasco is the second viscous oil development in the area. It began production in 1998 and is situated to the west of the Kuperuk field. Tarn produced about 17,000 barrels per day in 2006. It began production in 1999 and is located southwest of the Kuperuk field. Located 10 miles south of Tarn, Meltwater was discovered in 2000 and is produced from a single drill site.

West Sak

Discovered in 1971, West Sak is a shallow, viscous oil reserve situated above the Kuperuk field. West Sak's core area contains 3 billion barrels of oil but the oil is cold, thick and difficult to produce. In 2004, BP, ConocoPhillips and others approved the largest-ever viscous oil development program in Alaska. This \$500 million development has increased the current average 2006 production to about 18,000 barrels per day. The development is utilizing multi and tri-lateral drilling technology, along with extended reach drilling.



Oil Fields	Kuparuk	West Sak
Owners	ConocoPhillips (Oper.) ~55.2% BP ~39.2% Chevron ~5% ExxonMobil ~0.6%	ConocoPhillips (Oper.) ~52.2% BP ~37.0% Chevron ~5% ExxonMobil ~5.8%
Field Data		
Participating Field Area	185,000 acres	30,000 acres
Original Oil in Place	5.9 billion barrels	3.0 billion barrels*
Original Gas in Place	2.7 trillion SCF	
Cumulative Oil Production	Gross Field	Gross Field*
Production 12/31/06 (millions of barrels of oil equivalent)	2,068	26.5
Current Rates (12/31/06)	Gross Field	Gross Field
Oil (thousands BOE/day)	121	18.9
Number of Wells (12/31/06)		
Oil Producers	469	49
Gas Injection	0	0
Water Injection	89	46
WAG Injection	249	2

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

Satellite Fields	Tabasco	Tarn	Meltwater
Owners	ConocoPhillips (Oper.) ~55.3% BP ~39.3% Chevron ~5% ExxonMobil ~0.4%	ConocoPhillips (Oper.) ~55.3% BP ~39.3% Chevron ~5% ExxonMobil ~0.4%	ConocoPhillips (Oper.) ~55.4% BP ~39.4% Chevron ~5% ExxonMobil ~0.2%
Field Data			
Participating Field Area	4,000 acres	12,000 acres	7,000 acres
Original Oil in Place	0.2 billion barrels	0.3 billion barrels	0.1 billion barrels
Cumulative Oil Production	Gross Field	Gross Field	Gross Field
Production 12/31/06 (millions of barrels of oil equivalent)	12.7	79.7	11.1
Current Rates (12/31/06)	Gross Field	Gross Field	Gross Field
Oil (thousands BOE/day)	4.1	17.1	2.9
Number of Wells (12/31/06)			
Oil Producers	7	24	11
Gas Injection	0	0	0
Water Injection	1	0	0
WAG Injection	0	15	7

Source: State of Alaska Oil and Gas Conservation Commission.

** Water Alternating Gas Injectors.

Endicott



A causeway links Endicott to shore.

Located less than three miles offshore, Endicott is the first continuously producing offshore field in the Arctic. The field is also the premiere model 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 14 feet of water.

Endicott is connected with shore by a causeway. The field was developed as a self-contained community with its own production and living facilities, including a power generation facility, a desalination plant for making drinking water, a sewage treatment plant, oil processing facilities, fire fighting equipment, a medical facility and fitness and recreation center.

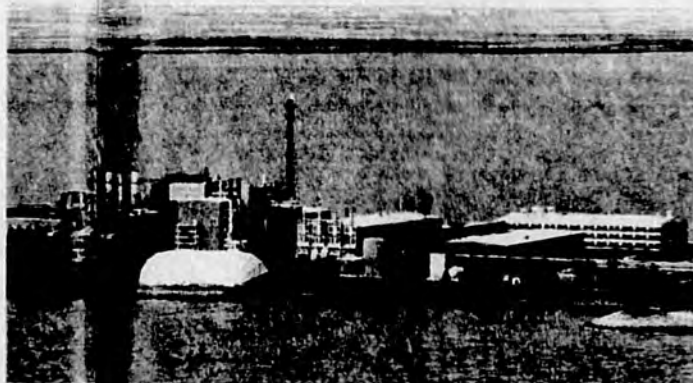
Endicott's oil-bearing rocks lie in the Kekikuk formation, a shale and sandstone formation similar to the Sadlerochit in the Prudhoe Bay field. The oil column lies about 10,000 feet beneath the surface and consists of the highest quality reservoir rock currently producing on the North Slope.

Discovered in 1978, the field began production in 1987 and reached its peak production of 120,000 barrels per day in the early 90s. Cumulative production from the Endicott field is 472 million barrels of oil equivalent (BOE). BP's cumulative net production is approximately 274 million BOE. Endicott holds the Occupational Safety and Health Administration (OSHA) Voluntary Protection Program (VPP) star award status.

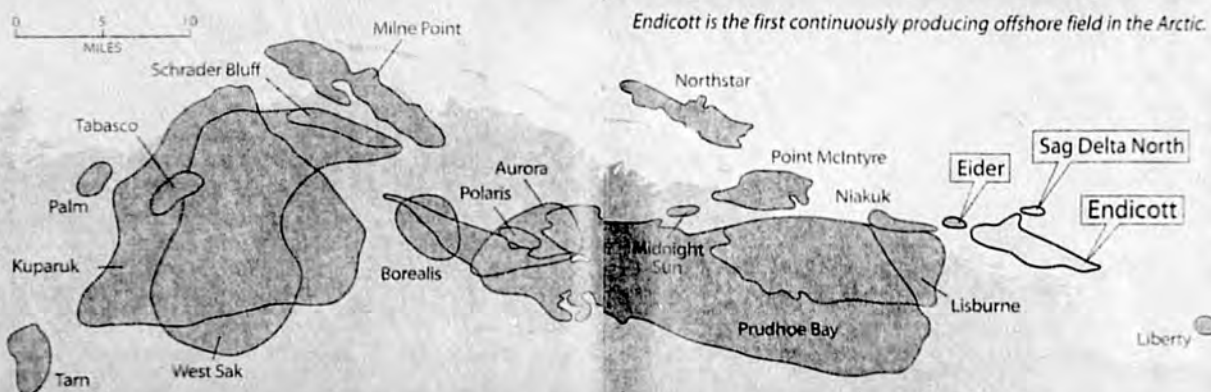
Endicott was developed at a cost of slightly more than \$1 billion. The 45-acre Main Production Island contains the operations center and processing facilities. Processed oil is sent through a 24-mile pipeline to the Trans Alaska Pipeline System.

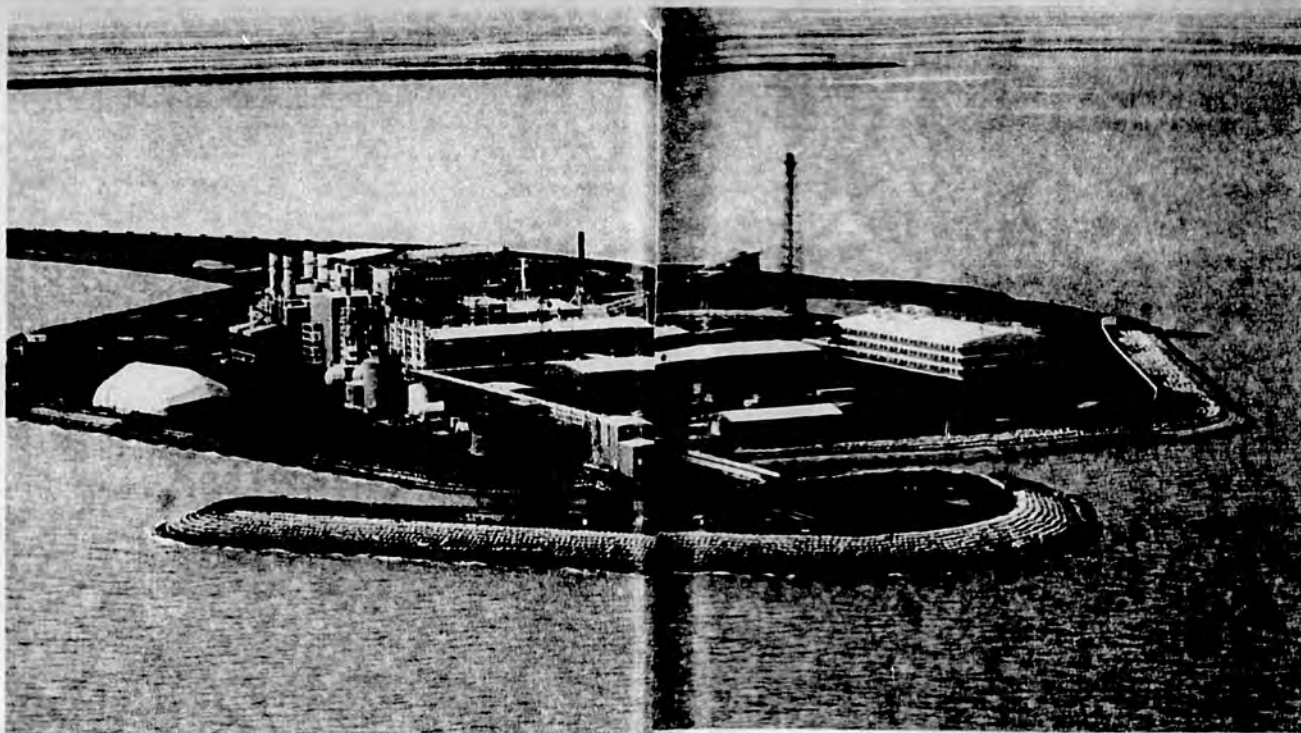
Endicott satellites

Two satellite fields drilled from Endicott's Main Production Island access oil from the Ivishak formation. Eider consists of two highly deviated wells that produce about 110 barrels per day, while Sag Delta North produces about 117 barrels per day.



Endicott is the first continuously producing offshore field in the Arctic.





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. ~.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 12/31/06 (millions of barrels of oil equivalent)	438.7	2.8	8.2
Current Rates (12/31/06)	Gross Field	Gross Field	Gross Field
Oil (thousands BOE/day)	15.1	0.1	0.2
Gas (millions SCF/day)	393.3	8	0.21
Number of Wells (12/31/06)			
Oil Producers	52	2	1
Gas Injection	4	0	0
Water Injection	18	0	2
WAG Injection	1	0	0

Source: State of Alaska Oil and Gas Conservation Commission.

** Water Alternating Gas Injectors.

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 pipeline. Northstar delivers its oil via a sub sea pipeline.



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

Northstar was developed by BP when it acquired a major interest in 1995. The unit sits in state and federal waters and produces about 52,000 of oil equivalent (BOE) per day from the Ivishak and Shublik formations. BP's net production is about 38,000 BOE per day. Cumulative production from North Star is 109 million BOE. BP's net share is approximately 79 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 6-mile sub sea pipeline has a wall thickness triple those 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 is located on the shore of Mikkelsen Bay about 35 miles east of Prudhoe Bay and is the first BP field to be developed remotely from Prudhoe Bay infrastructure.

The field was discovered in 1990 by Conoco and brought into production in 1998. Poor connectivity between producing zones caused oil recovery to quickly drop and production dipped to about 2,000 bbl/day by 1999. The field was put into warm shutdown in 2003. Higher oil prices led to the field's restart in 2005.

In 2006, the field produced about 1,300 BOE per day from the Badami sandstone. BP's net production is 1,100 BOE per day. The cumulative production of the field is 5 million BOE. BP's net share is 4 million BOE.

Oil Fields	North Star	Badami
Owners	BP (Operator) ~98.6% Murphy Oil ~1.4%	BP (Operator) ~100%
Field Data		
Participating Field Area	17,682 acres	37,402 acres
Original Oil in Place	176 million barrels	80 million barrels
Cumulative Oil Production	Gross Field	Gross Field
Production 12/31/06 (millions of barrels of oil equivalent)	108.5	5
Current Rates (12/31/06)	Gross Field	Gross Field
Oil (thousands BOE/day)	51.7	1.3
Gas (millions SCF/day)	390	11.5
Water (thousands bbl/day)	13.9	0
Number of Wells (12/31/06)		
Oil Producers	19	6
Gas Injection	6	0
Water Injection	0	1
WAG Injection**	0	1

Source: State of Alaska Oil and Gas Conservation Commission.

** Water Alternating Gas Injectors.



Summary

BP North Slope Oil Fields

Original Oil in Place	42.3 billion barrels	
Original Gas in Place	52.8 trillion SCF	
Cumulative Oil Production (billions of barrels of oil equivalent)	BP Net	Gross Field**
Production 12/31/06	5.8	14.9
Current Rates (12/31/06)	BP Net	Gross Field
Oil (thousands BOE/day)	238	845*

*Source: State of Alaska. Average daily production based on fiscal year.

**Cum North Slope production (includes full year 2006 production).

Field area

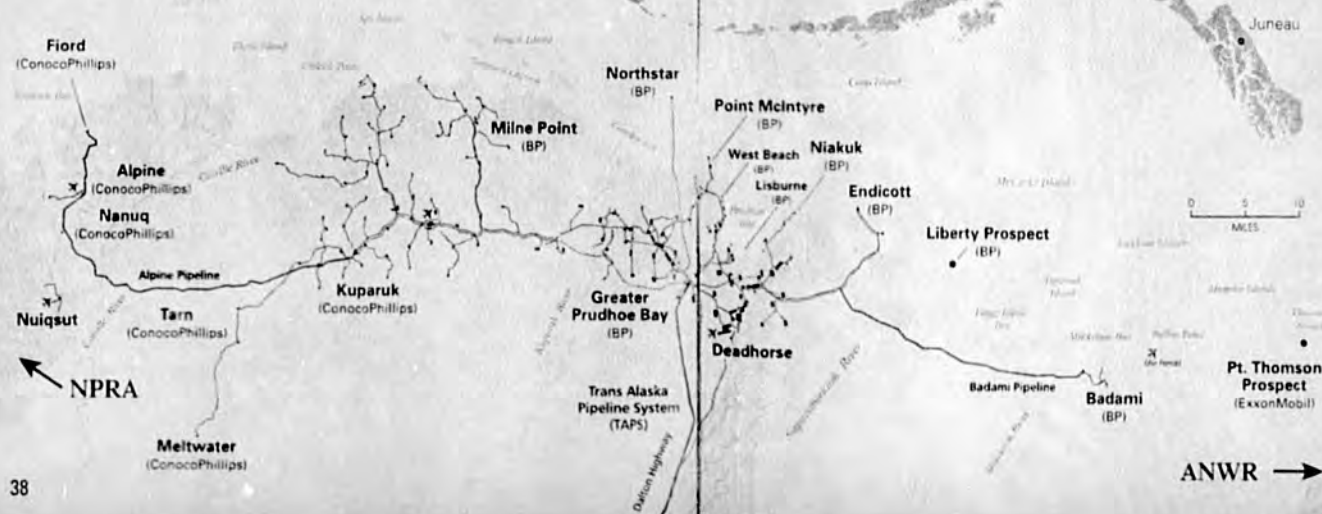
Unit boundaries equal about 693,484 acres.

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

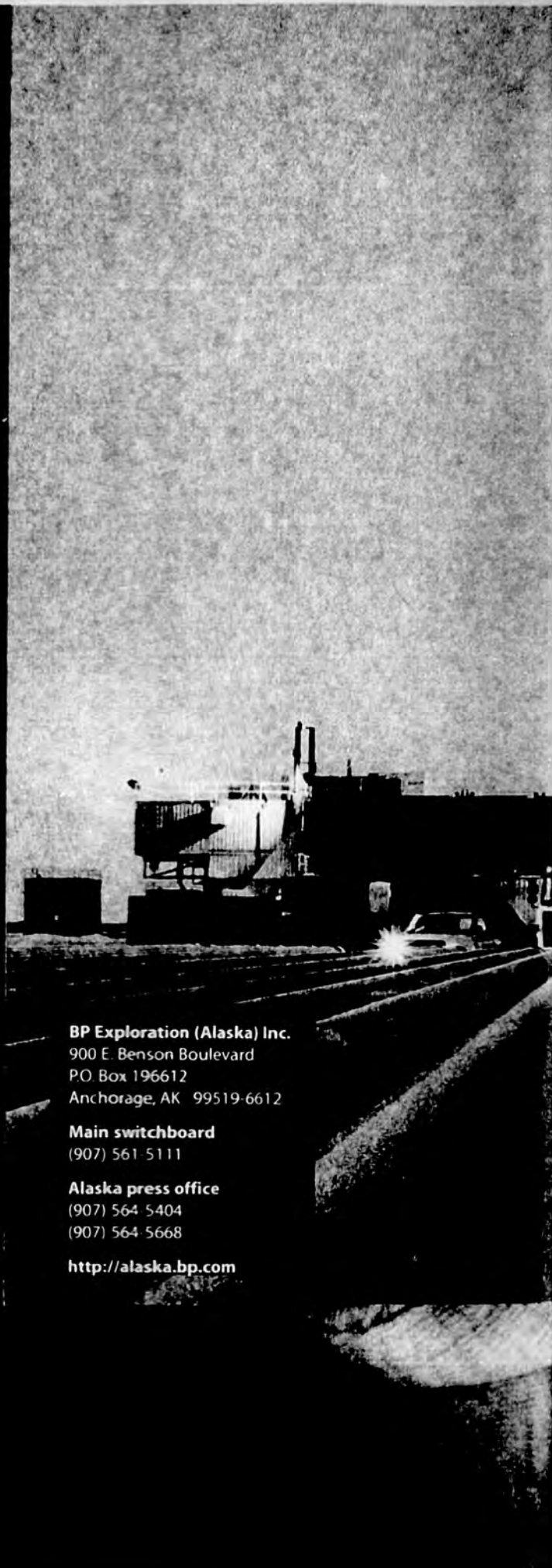
Prudhoe Bay is about 600 air miles north of Anchorage and about 1,200 miles south of the North Pole. It is about 250 miles north of the Arctic Circle.

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.

MAP LOCATION





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Anchorage, AK 99519-6612

Main switchboard
(907) 561-5111

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(907) 564-5668

<http://alaska.bp.com>

HB2001 Testimony

October 22, 2007

ConocoPhillips Alaska

Kevin Mitchell

Vice President, Finance & Administration

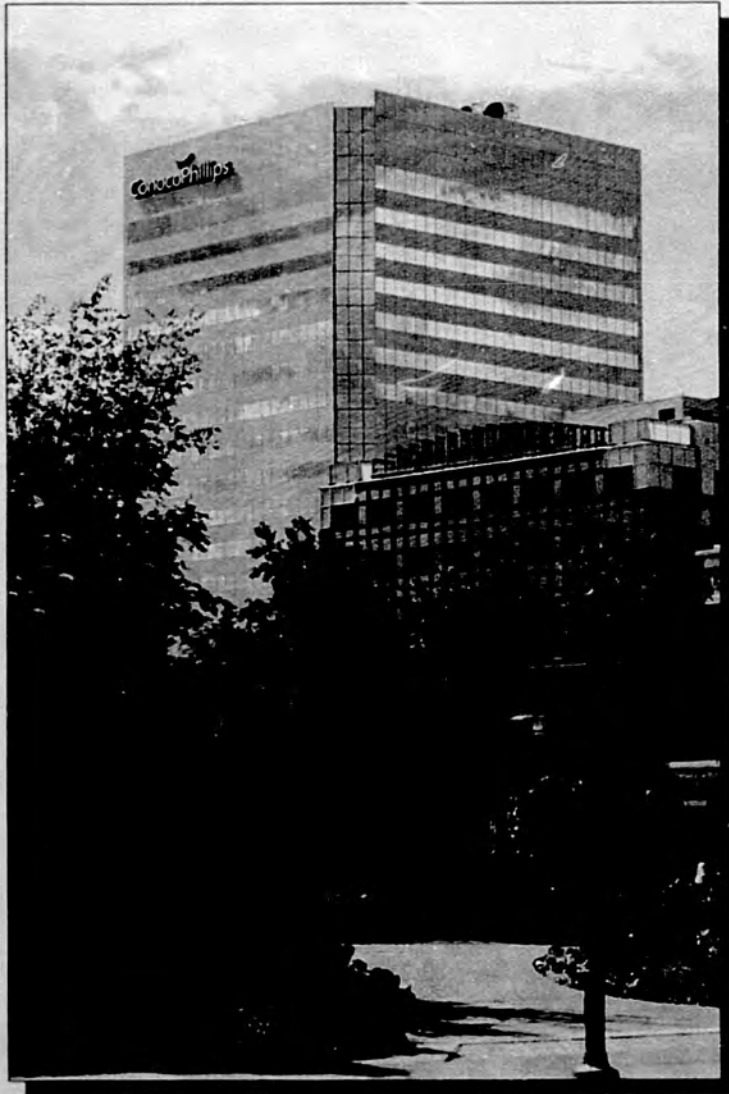
Jim Taylor

Vice President, Commercial Assets

Agenda

- ConocoPhillips overview
- Summary comment
- Specifics on the bill:
 - Reporting requirements
 - Cost deductibility
 - Transitional Investment Expenditure (TIE) credits
 - 10% minimum/legacy fields
 - Impact on investment

ConocoPhillips in Alaska Today

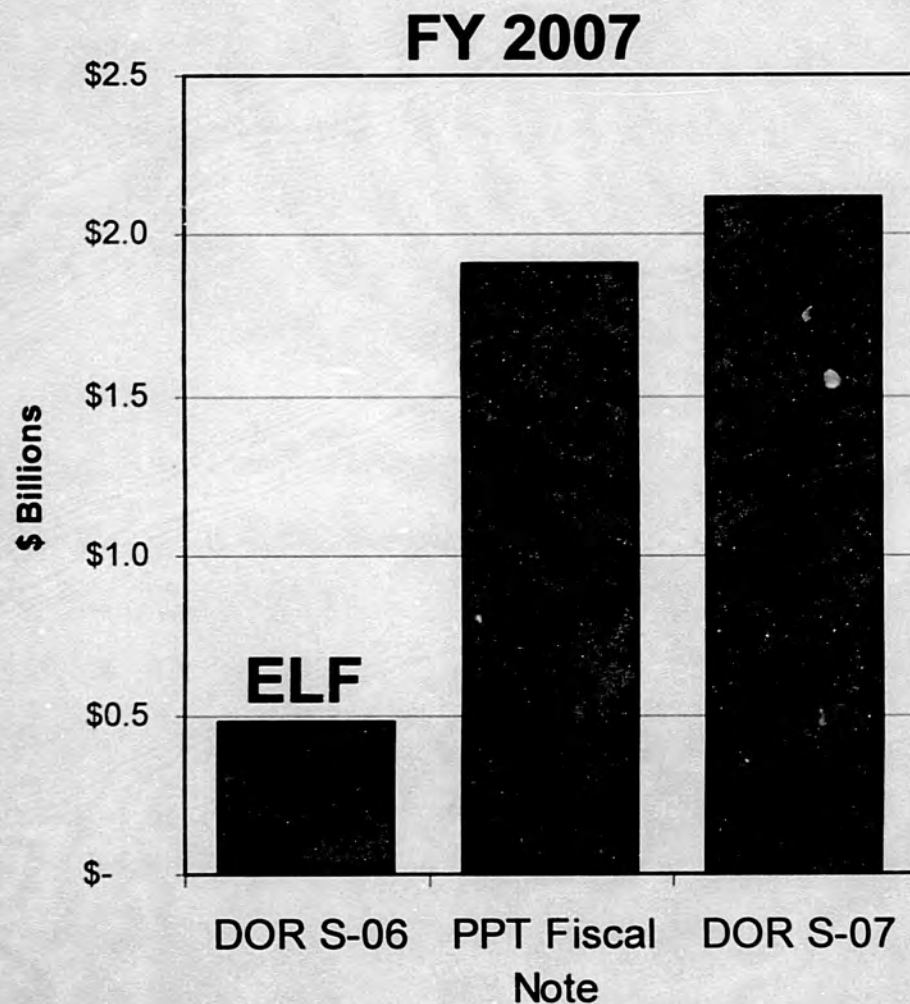


- **Alaska's #1 Oil Producer**
 - 2006 production: 280,000 barrels of oil per day
- **Alaska's #1 Gas Producer**
 - 2006 production: 145 million cubic feet per day
- **Alaska's Largest Lease Holder**
 - Interest in 1.7 million gross (federal) acres in the NPRA
 - Nearly 2.6 million gross undeveloped acres in total outside of producing fields
- **Alaska's Leading Explorer**
 - 60 exploration wells since 1999, including 17 wells in NPRA
- **Largest Industry Community Supporter**
 - 2006 > \$12 Million Contributions
 - 2007 > \$14 million (projected)
- **1,093 Employees**
 - Annual payroll over \$122 Million
- **Largest Royalty and Taxpayer**
 - 2006 taxes paid to government: \$2.3 billion
 - Royalties: \$730 million
- **Alaska Capital and Operating Budget**
 - More than \$12 Billion invested over past 10 years

Summary Comment

- Common interest between state and industry
- Too early to change PPT
- Uncertainty created by frequency of tax changes
- Impact on investment

Revenue Forecasts



- Forecasting uncertainty
- Price
- Production
- Operating costs
- Capital costs

Reporting to State

- Generally supportive of additional transparency
- But, certain areas of concern in bill:
 - Exploration
 - DOR allowed to share all information with DNR without limits
 - DNR determination of geological success in credit application
 - Exploration credit application waives confidentiality rights
 - Forecast data requests should rely on information already provided by unit operator to partners
 - “Whatever else” language is too broad

Cost Deductibility

- Net profit approach
- Inappropriate for regulatory agency to define deductions
- Unreliable advisory bulletins
- Unscheduled maintenance exclusion:
 - Definitions/complexity
 - Audit challenges
 - Disallowance of maintenance that brings production back online
 - Retroactive implementation
- Exclusion for dismantlement costs
 - Legitimate leasehold cost

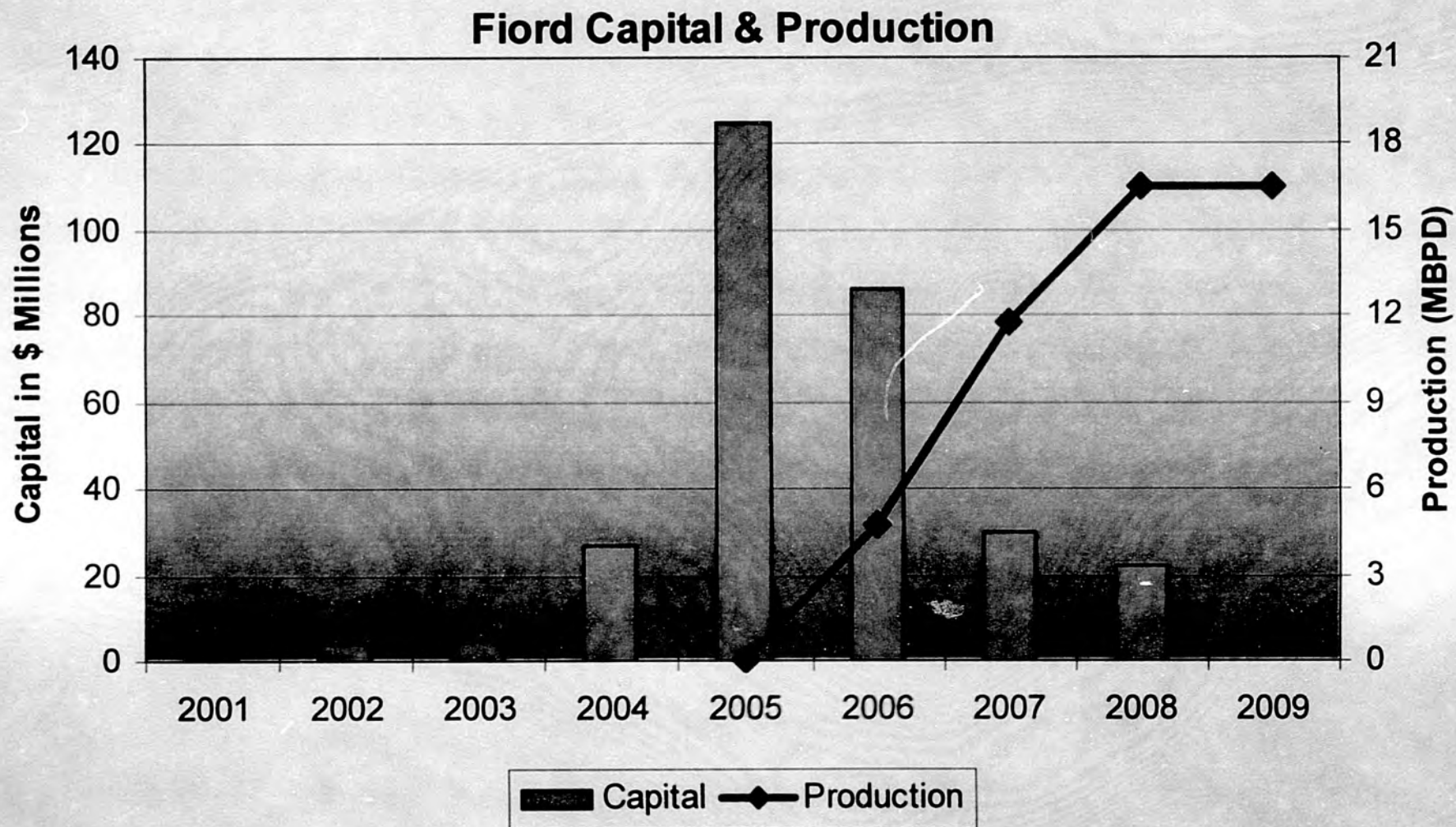
Cost Deductibility

- Crude oil topping plant exclusion
 - Current diesel production at Prudhoe and Kuparuk
 - 2 options to meet ultra low sulfur diesel requirements:
 - Build ULSD plant at Kuparuk to serve all North Slope needs
 - Transport to North Slope from Alaska or L48 supply

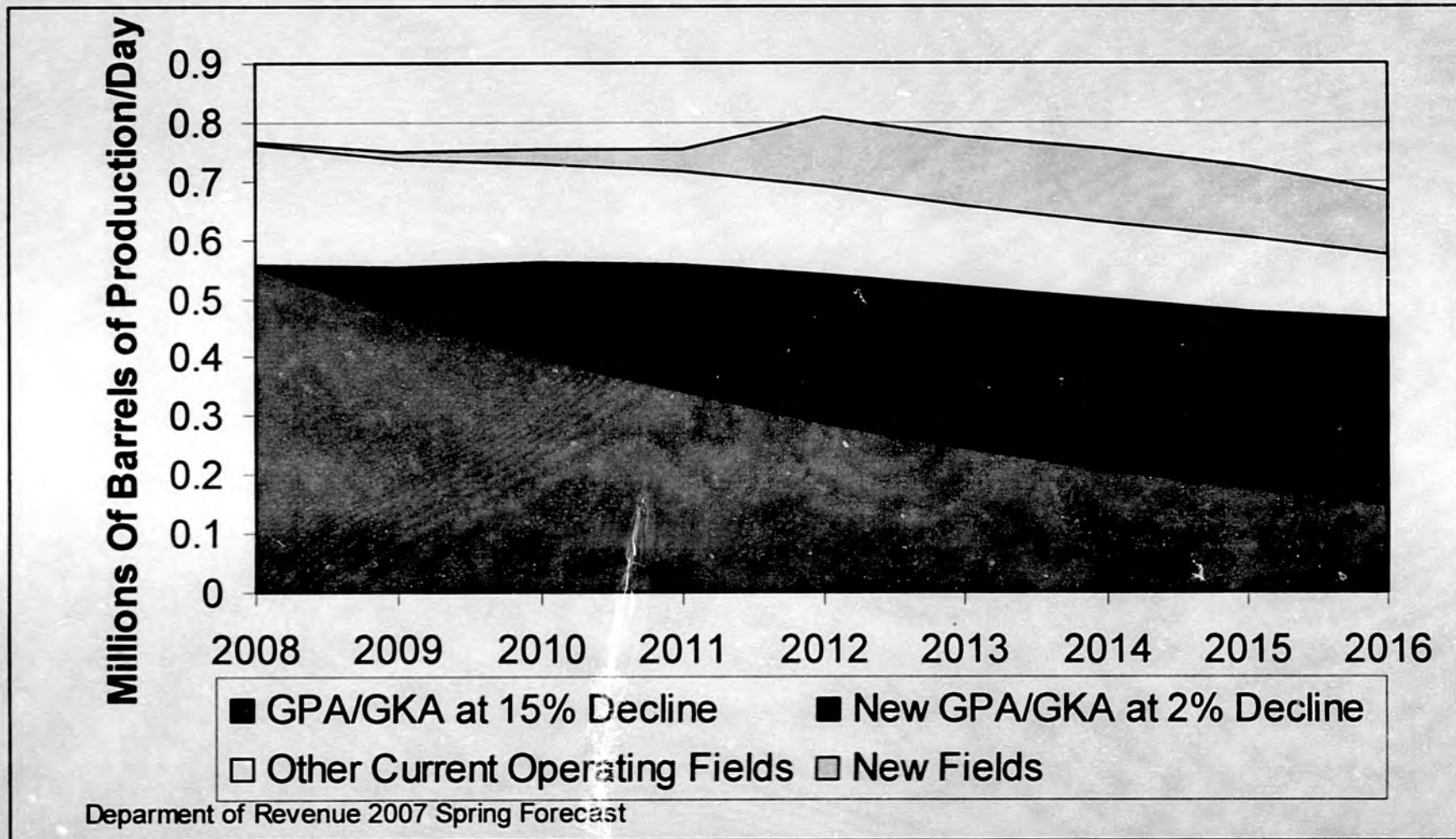
TIE Credits

- Included in PPT legislation to recognize the impact of “changing rules” after investment decisions made
- Provides for equitable treatment of past expenditures
- TIE credits soften the impact of fiscal instability

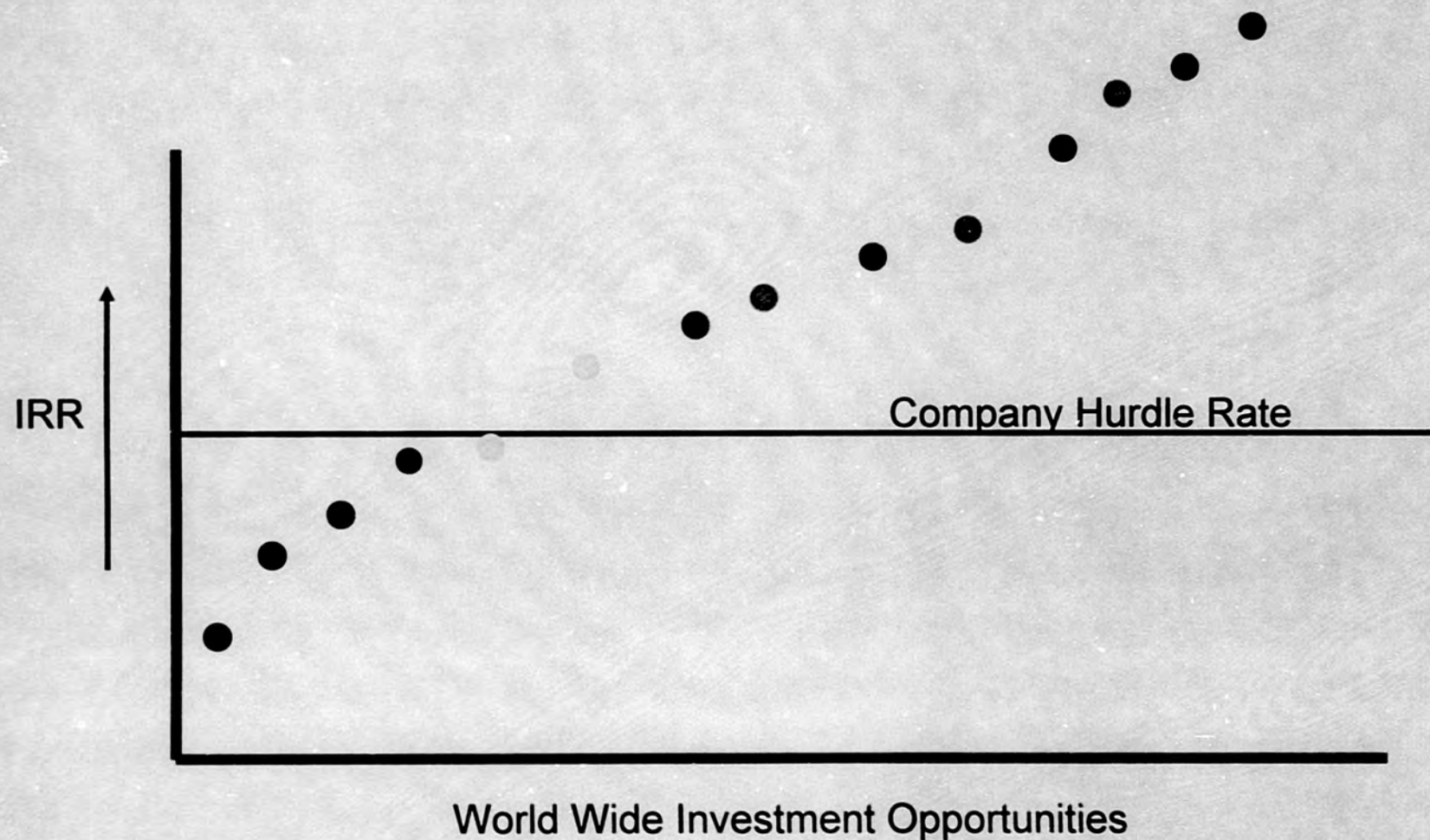
Example of TIE Impact Fiord Development



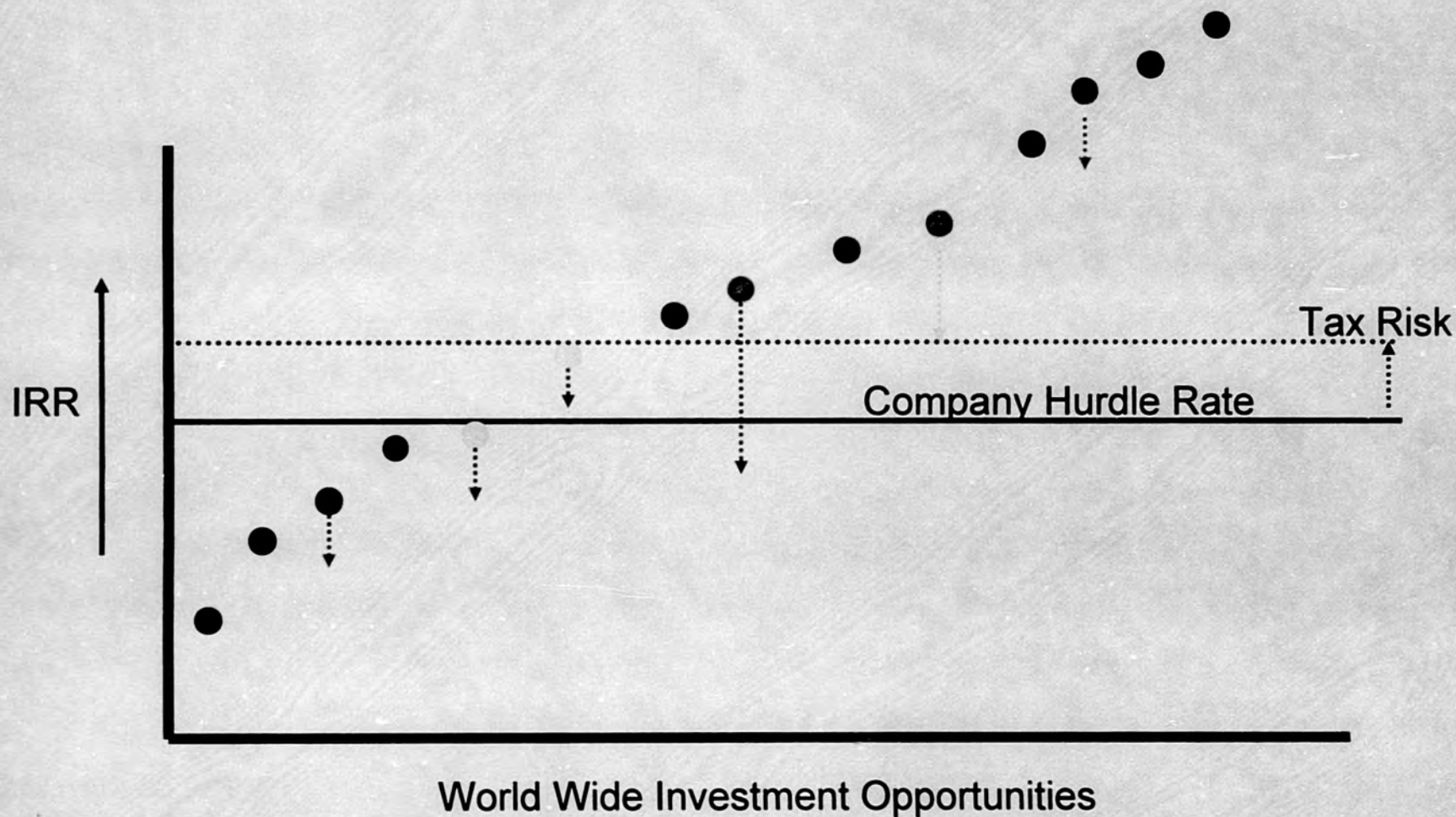
Significance of Legacy Assets



Tax Change Impacts On Project Economics

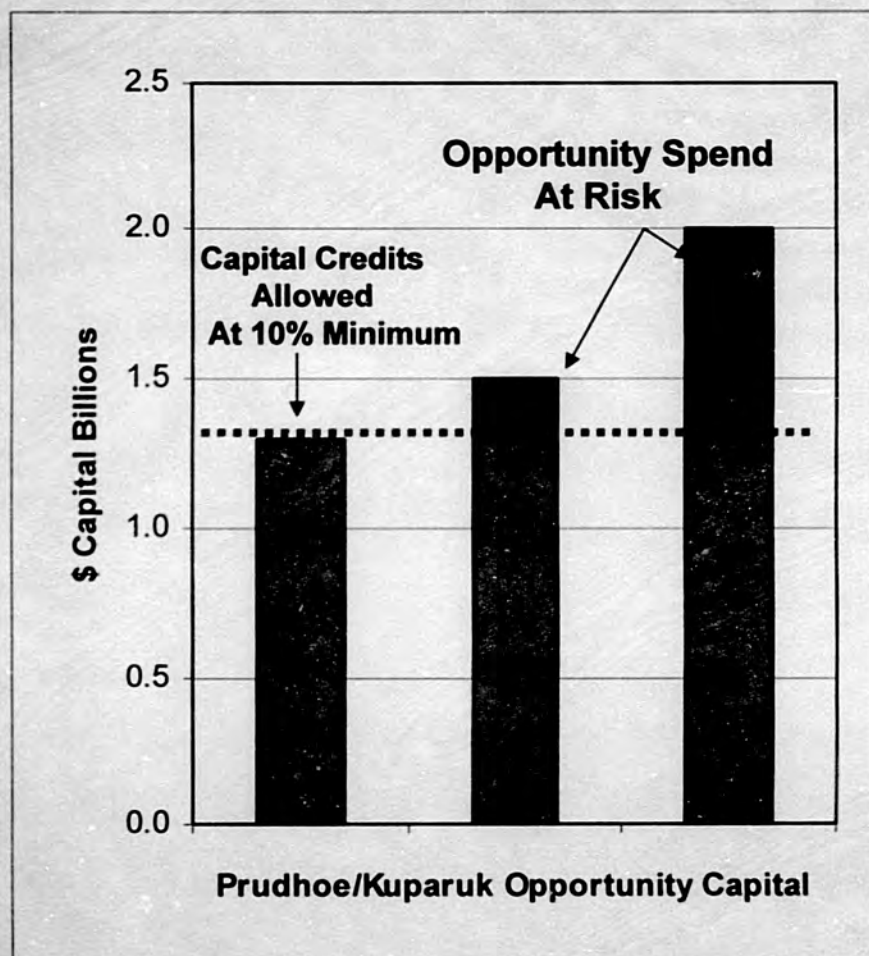


Tax Change Impacts On Project Economics

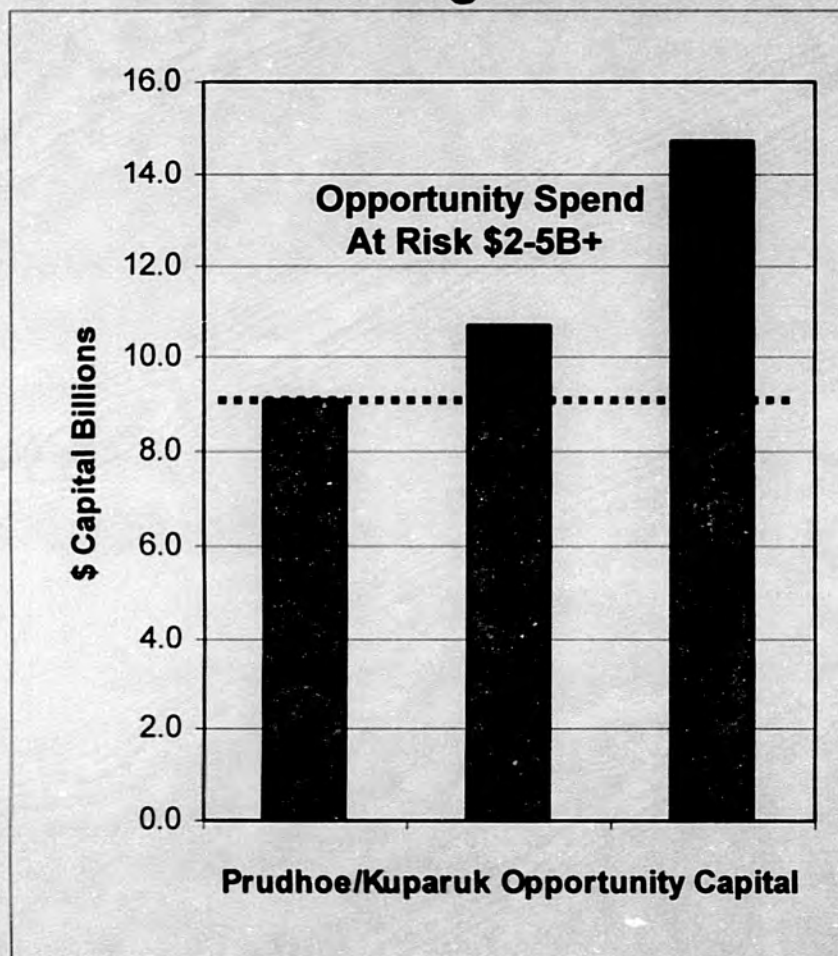


Potential Legacy Impact on Capital Spend

Annual View



Through 2014



Impact on Investment

	PPT	Bill 25/20	Bill 10% Min
Project 1	Economic	Economic	Marginal
Project 2	Economic	Marginal	Marginal
Project 3	Economic	Economic	Marginal
Project 4	Marginal	Marginal	Not Economic
Project 5	Economic	Economic	Not Economic
Project 6	Marginal	Marginal	Not Economic

- Six real projects under evaluation
- \$3.5-\$4.0B gross capital spend
- Over \$6.0B revenue to state
- 250MM Bbls
- 1st production 2010-2013

Closing Comment

- State and industry need to be aligned to foster investment environment
- Too early to significantly change PPT
 - Forecast uncertainties
 - Revenue Projections are being met based upon the 2007 actuals
- Uncertainty created by frequency of tax changes alters investor's risk tolerance
- Selective deductability adds confusion, administrative complexity and will modify cost behavior
- Increase tax erodes investment value by reducing cash available for reinvestment
- 10% Legacy Floor is a disincentive to investment
 - Limits amount of capital which can qualify for deductability rendering the marginal project uneconomic
 - Low price can invoke the minimum at the wrong time

Comments On ACES Petroleum Tax Proposal, October, 2007
By Ken Thompson, Lead Director of AVCG/Brooks Range Petroleum

Personal Background

For the record, my name is Ken Thompson. I reside at 12031 Lilac Drive, Anchorage, Alaska. I am the Managing Director for Alaska Venture Capital Group, or AVCG LLC, an independent oil exploration company formed with a sole focus on the North Slope of Alaska. AVCG is a privately held member LLC comprised of private equity investors made up of 15 independent oil and gas companies and individuals from Kansas and me as an owner/member partner from Alaska. AVCG has a technical and operational services' subsidiary company called Brooks Range Petroleum, with offices and staff in Anchorage. In Alaska and on the North Slope, we operate under the name Brooks Range Petroleum.

AVCG has lease holdings and explores currently only in Alaska...and nowhere else. AVCG/Brooks Range Petroleum likes to think of our company as "Alaska's *Independent Oil and Gas Company.*"

AVCG LLC has been very active in the past seven North Slope areawide lease sales and active in acquiring acreage held by other companies where we see potential. We and our partners currently hold over 300,000 acres of exploration leases in five exploration prospect areas on the Slope. Our exploration strategy is to explore in the central part of the North Slope for fields in the 10-100+ million barrels range, fields that may be too small for the giant producers but satisfy as niche fields that can be "company makers" for a small independent. We believe there are hundreds of millions if not billions of barrels of oil left on the central North Slope in smaller fields of this size for small independents like ours that want to take this type of exploration risk.

Last year, AVCG LLC announced joint venture agreements with two Canadian independents, TG World Energy and Bow Valley Energy, and with a private exploration company from Houston, Ramshorn Exploration. Together, as working interest co-owners we are exploring the central part of the North Slope.

In the winter of 2006, AVCG participated with an ownership interest in the Cronus exploration well about 10 miles southwest of the Kuparuk Field, operated by Pioneer Natural Resources. Unfortunately, that well was a dry hole.

This past winter for the first time, our operations subsidiary, Brooks Range Petroleum operated the drilling of two exploration wells for our working interest partners in the Gwydyr Bay area of the North Slope, just northwest of Prudhoe Bay. One well, the Sak River #1, was a dry hole, but we were excited to announce earlier this year that our Northshore #1 well northwest of the Prudhoe Bay Field did strike oil. We plan to complete and test this well this winter. In addition, we ran a 130-square mile 3D

seismic survey over our acreage and surrounding area in the Gwydyr Bay area on the North Slope. In total this past drilling season, our JV Group invested over \$44 million on land, seismic and drilling activities.

This winter our Joint Venture Group will be among the most active of explorers as we plan to shoot over 200 square miles of new seismic data on the extreme western and eastern sides of the Central North Slope and to drill up to four exploration wells. We plan to test the Northshore #1 well and also drill one or two other exploration wells nearby to see if we can discover a sufficient volume of oil to warrant a commercial development at Gywdyr Bay. We will drill our Tofkat #1 well south of the Alpine Field and also drill a fourth exploration well on a prospect to be named. In total, our group will spend over \$40 million in seismic and exploratory drilling in winter 2008. If our Northshore oil completion test is as suspected and one of the wells strikes oil close by, we may proceed with Northshore development with more substantial capital investment in the second half of 2008.

My comments today represent the perspectives of a small, independent exploration company that is actively exploring on the North Slope with a good level of activity, generally on prospects that because of smaller size no longer interests the major companies. At the end of next drilling season, AVCG since 1999 and our partners since last year will have jointly invested over \$100 million in Alaska even though none in our group have generated any revenues yet from Alaska oil, so we sincerely appreciate being listened to. We think in the long run we can bring substantial, incremental value to the State of Alaska. Please wish us good luck.

Many of you also know me as the past President of ARCO Alaska, Inc. from 1994-1998. I also served as Executive Vice-President for ARCO and head of global oil and gas exploration for ARCO. I do have exploration and production experience in 10 U.S. states and in over 20 countries throughout the world, so I'll also share my perspective in how I see the ACES bill in the context of competitiveness in the United States and in the world.

General Comments On ACES Legislation

At this point, I would like to address various key points in the ACES legislation.

First, our company prefers that the PPT be allowed to run its course in the next few years, and that ACES not be approved with its current provisions. I agree with Dr. Pedro van Meurs that in the light of declining oil production in the state of Alaska and prospectivity trending to smaller field sizes, the State should not once again increase its taxes after having done so last year. I will tell you that when recruiting companies to join in our Alaska ventures in 2005 and 2006, many were concerned about the threat of tax increases in Alaska. PPT proved tax increases were not a threat but a reality. Adding yet another tax increase via the ACES bill this year shows instability

in Alaska's tax policy which results in uncertainty and risk when making investment decisions.

I heard that consultant Daniel Johnston differed strongly from Dr. van Meurs and urged the oil industry to understand the "cloud of corruption" over the existing Petroleum Profits Tax, or PPT, and that this alone provides a good reason to change PPT. I challenge Daniel Johnston that the bushel should not be thrown out because of a few bad apples.

In fact, last year during the PPT debates, I recall those who are guilty of paying bribes and some who are accused of taking bribes actually supported a 20% base tax rate, not the 22.5% base rate that was finally adopted. In fact, I'd like to think that the almost all in the Legislature and in Industry were honest, that they could be trusted in their deliberations last year, and that the final answer of PPT was a good answer and an honorable answer.

It is also very important to keep in mind that the progressivity tax was added at high oil prices to drive the real tax rate to even higher levels than 22.5%, with a range exceeding 30% now possible at certain prices. And let's not forget to tack on the royalty, the corporate tax, the ad valorem property tax, and environmental and permitting fees. It appeared to me that the checks and balances in the system worked in the Legislature last year, and I applaud the honesty of the legislators who in the end made a positive difference.

But I sit here feeling as if the honest and trustworthy investors in this industry are being punished alongside the guilty. I personally think this will have negative consequences for Alaska in the long haul in relationships and even in sustainable increased value.

But I am politically astute enough to know that the ACES train is moving fast down the track, so I can stand out of the way or jump on board and try to make the ACES bill better before we reach derailment in the long-term relationships between this industry I love and this State I love.

So, I have some suggestions of things not to change and things to change in the ACES proposal.

Five Things Not To Change In ACES

- 1) **Keep the exploration and development investment tax credits.** For a small explorer startup company like AVCG LLC, the exploration economics with the exploration tax credits ranging from 20-40% as provided by PPT and with ACES are more favorable with an improvement in the investor's rate of return as compared with Alaska's old severance tax system. Near-term cash flow because of the investment tax credits is higher which improves the return

on investment. Plus refund of cash to companies like AVCG and our working interest partners via the credits mean that we can apply that cash to our capital budget the next year to run adequate seismic and do additional drilling that increases the chance of more oil production and reserves for us and for the State.

Likewise, the credits for losses for a startup company like ours while we establish production and also the development investment credit can take substantial risk out of development of smaller fields that our company is focusing on. May of these smaller fields can add up over time and provide significant incremental revenue to the State.

2) Keep the "standard tax deduction/exemption" for smaller companies.

The "Small Producer Tax Credit" that exempts up to the first \$12,000,000 in production taxes for smaller companies can allow us to return a larger share of our annual cash flow for exploration and investment while we build the company to a critical mass of reserves and production necessary to expand staffing and have a routine level of major capital spending each year.

3) Keep the new ACES tax credit allowance for qualified delineation wells.

A new proposal in the ACES bill that was not in the PPT law is the possible tax credit allowance for the investment in up to two delineation wells following a discovery. This would be very helpful to small explorers as well as for large companies on the North Slope where often one well is not enough to determine if field size is large enough to warrant development.

A real case in point is that should we have a discovery this coming winter at our Tofkat exploration well on the western side of the Slope, we will have to drill one or two delineation wells to confirm if field size is sufficient to develop the resource at this remote location. Often, due to the nature of these complex stratigraphic traps where sands unpredictably come and go, the delineation wells can be almost as risky as the initial exploration well. Having a credit where the State, in a real sense, is sharing in the risk will – I think – expedite delineation of new fields and advance development for revenues.

4) Keep the revised progressivity tax rate at 0.2% per dollar increase in oil price. The PPT tax law had an incremental tax rate of 0.25% per each dollar increase in oil price above a trigger price while the new ACES reduces this incremental tax rate to 0.2% per dollar increase in oil price at a trigger price. While we can debate all day long the competitiveness of Alaska's tax rate with other countries' fiscal systems, giving some reduction in this surcharge keeps the government take at more reasonable levels. However, as I'll outline below, I would change the ACES trigger price back to \$40 per barrel net and not the proposed \$30 per barrel net if Alaska wants to better balance revenues with industry capital investment at low prices as I'll more fully discuss.

- 5) **Do establish the Oil and Gas Tax Credit Fund** for the purposes of purchasing certain tax credits from explorers and producers. This ACES provision would establish a procedure and standard for appropriation into this fund and management of this fund. Having a clear and transparent way for small explorers to receive their credits at full value is extremely important for AVCG to then be able to plow those credits back into seismic and exploration on the North Slope.

Four Things To Change In ACES

- 1) **Change the recovery of tax credits from two years as proposed in ACES back to the recovery of credits in one year currently provided for in the PPT law.** In the PPT law, a company could file for the various credits, and if approved, would receive those full capital credits not to exceed credits of \$25 million per company. In the new ACES law, while the cap has been removed which is very positive, the credits are refunded over two years instead of over one year, e.g., 50% of qualified credits can be applied for in the first year once a well is completed or abandoned and 50% in the following year.

For a small company like ours, this will definitely affect our capital spending in a given winter as we plow all the credit refunds back into seismic or exploration drilling. As a very real example, AVCG and our working interest owners are projecting to spend \$41 million in seismic and exploration drilling this coming winter and likely around the same in 2009. We calculate that we could receive \$16 million cash in qualified credits in mid-year 2008. So essentially, our working interest owners are planning to provide cash out of pocket of \$25 million for the 2009 drilling season; this is a fixed number based on cash availability in these small companies to spend toward the Alaska portfolio. If the State refunds only one-half of this credit in the first year, or only \$8 million instead of \$16 million, AVCG and our partners will still provide \$25 million out of our pockets as now planned and budgeted...meaning our overall spending in 2009 will be \$33 million, not \$41 million, i.e. \$25 million from our available funds and only \$8MM from the State. This would mean one less well that will be drilled by our group in 2009. And one less chance for another discovery that eventually could provide revenues to us all. With small companies, this is just the way our cash flow situation works. And for some of our AVCG investors like me, when I say "out of pocket," I mean "out of pocket."

So, we hope the full credit can be applied for and refunded in a given year. We hope this happens for all of industry. As an innovative compromise, however, the Legislature may consider a "Small Company Refund" provision that allows for companies that meet the no production or low production measures in the "Small Company Tax Credit" provision of the PPT law - that remains in ACES - to receive tax credit refunds that are fully refunded in the

first year for qualified costs. Once a company grows in production beyond this "small company" measure with more substantial cash flow, perhaps refunds of 50% each year would apply as outlined in ACES.

- 2) **Change the base tax rate in ACES from 25% back to the PPT tax rate of 22.5%, and re-review again in 2011 after some time has passed as allowed for in current law.** As I mentioned in my introduction, I felt the 22.5% base tax rate was reasonable. And the real tax rate is much higher with the tax progressivity factor. But what is fair, and how exactly is "fair" determined?

I saw a copy of a presentation entitled "Guiding Principles For A New Production Tax System" by the Department of Revenue urging the changes in ACES, arguing that the average government take in various international countries averaged 67% for all types of fiscal regimes internationally, averaged 74% for production sharing agreements, but only 55% for tax and royalty regimes internationally. Somehow, the Department of Revenue representatives concluded an average of 58% as provided for in ACES would be close to the average of 67% for all types of regimes internationally.

First, the average recommended to Alaska is the average of all regimes, i.e. the averaging of government take from tax and royalty regimes with the government take from production sharing agreement (PSA) regimes. In some countries that I worked in that had production sharing regimes, the risk profile for capital development was often much different than in regimes that use a tax and royalty regime such as Alaska. In PSA countries, it was not unusual for a producer on capital projects to have a very low initial tax burden until the capital investment was fully recovered plus a negotiated rate-of-return was achieved. Then and only then was the government take increased substantially...thus giving the average take for such countries as 74%. But the risk profile was often much better than Alaska, i.e. there was up front recovery of capital and a preferred investor rate-of-return. That is not the risk profile of Alaska when a company first has production...the ACES high tax rate and the added progressivity tax will start immediately along with royalties, corporate taxes, property tax and other charges rather than allowing for recovery of capital and a contractual rate-of-return.

As another distinction, most of the individual people and company investors specifically in AVCG, LLC, do not consider international regimes as areas to consider as competition for our investment dollars with Alaska. Rather, the main competition for most AVCG Owners' cash is in other states in the U.S. I found it astounding and concerning that the average of 67% for all international regimes did not consider weight-averaging in the major American producing states. As examples, the current government takes in the Gulf of Mexico offshore – one of the main competing areas for Alaska investment

dollars – averages 45%. This is under consideration by the U.S. government for increase, but it is highly doubtful with the boom going on in deep water exploration and development that the U.S. government would increase the government take from 45% to 68%.

In other producing states that compete for investment by our AVCG investors, the state and federal combined government takes in 2006 were as follows and averaged 45-57%:

U.S. Gulf of Mexico	45%
Colorado	51%
Wyoming	52%
Kansas	53%
Texas	53%
New Mexico	53%
Oklahoma	53%
California	53%
Louisiana	57%

To my knowledge, these states do not have the added progressivity surcharge tax which further separates Alaska in government take from these competing states. I would argue that Alaska should have a government take of 55% if we were to maintain long-term competitiveness with these other states for investment dollars. Having said that, some of these states do not have the prospectivity of Alaska, so Alaska could command some premium in take, but certainly not as high as being proposed in ACES.

If Alaska set a government take at 60% to the government and 40% to the investor, the ACES legislation should be amended to allow for a base tax rate of 22.5% not 25%, should be amended to allow for a trigger price of \$40 per barrel and not \$30 per barrel, and the incremental progressivity tax rate increase should be 0.2% per dollar.

- 3) **Change the trigger price to \$40 per barrel net and not \$30 per barrel.** If the government take is to be the fair and equitable 60% and not the unfair 68%, the trigger price should stay the same as in the PPT law, i.e. \$40 per barrel net. If Alaska is to share in high prices with the progressivity surcharge tax, then Alaska should share in the pain of low prices. To amend the trigger price lower when and if prices collapse will be a false economy measure for the State of Alaska. When prices fall and a company's cash flow is sharply reduced, capital spending will fall. A "double whammy" to be taxed more with a progressivity tax at lower prices further reduces the amount of capital for re-investment.

- 4) **Consider some type of "Transitional Investment Expenditure (TIE)" tax credit.** This provision allowed for in PPT was repealed in ACES. While this provision does not greatly benefit our company, AVCG, because we did not have large seismic or exploration drilling costs between March 31, 2001, and April 1, 2006, it is important to other major investors in Alaska.

As an example, the largest explorer and developer in Alaska, ConocoPhillips, now with the ARCO heritage assets was hardest hit in tax exposure with the change from the old severance tax law to the PPT and now to ACES. I simply think allowing a good steward who is the largest explorer in Alaska some transition allowance to ease the pain of greatly increased taxes is the right thing to do and can only build better, more trusting relationships.

Again, this provision does not greatly benefit our company, however.

Concluding Remarks

This concludes my remarks. I tried to share the perspective of an independent exploration company that only invests in Alaska. My ultimate wish would be for the State to leave PPT alone and re-review it under the law as planned in 2011 or perhaps even in 2010. But if the ACES train has left the station and cannot be stopped, I urge you to at least consider the five things our company would not change in this bill and the four things we would change.

The above comments are offered with a hope that there can be an eventual win-win solution to this complex subject of the State realizing more revenues at higher prices while attracting exploration and development investors who can also realize upside at higher prices for the substantial risk they have taken in the remote and harsh environment of the North Slope. In the end, I hope both sides get a fair and equitable share at all price levels.

And my comments are offered with the highest sincerity that the State and Industry can someday restore a mutual trust at all levels.

I sincerely thank you for the opportunity to present my comments, and I would be happy to take any questions.

Respectfully submitted,

Ken Thompson