2/24/10 OIL & GAS PRODUCTION TAX: GAS ISSUES AND ALASKA'S FISCAL DESIGN (FILE 1)

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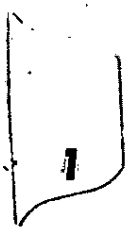


Senate Finance Committee

David Wood
24th February 2010

begin on p. 44
2/25/10

Gas Issues & Alaska's Fiscal Design

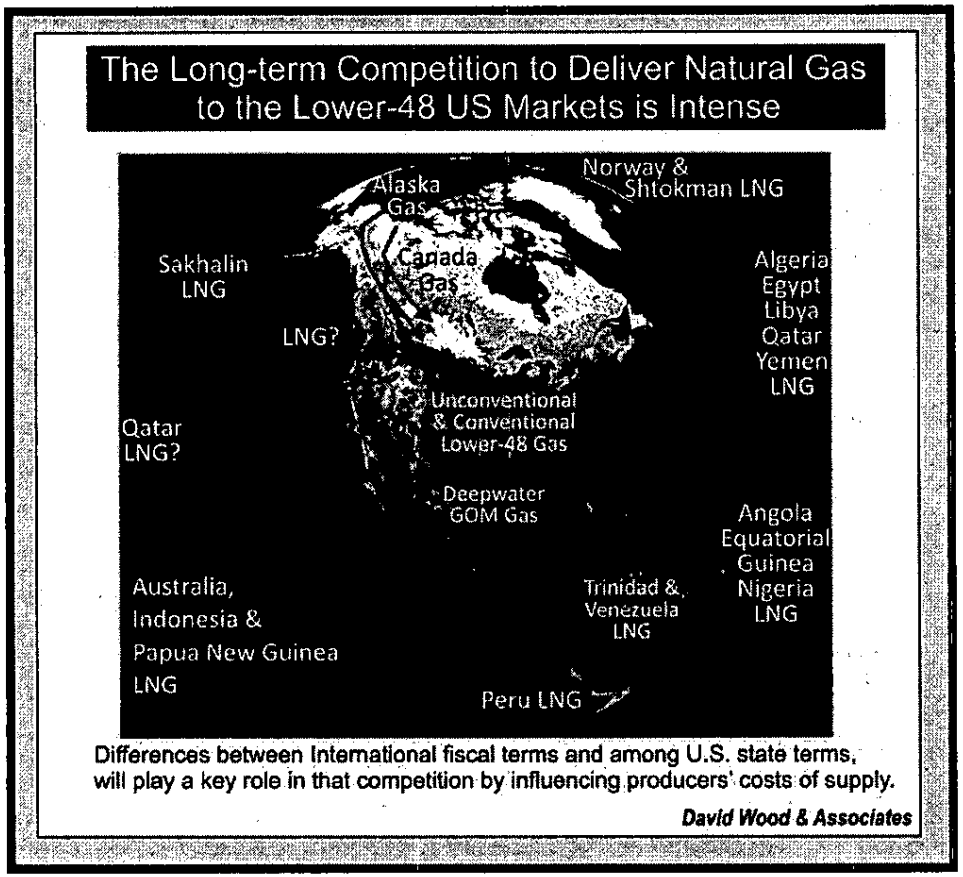
Presentation Structure

This presentation focuses the key issues pertaining to natural gas in Alaska in the context of establishing a long-term and enduring fiscal design.

- What are the issues for Alaska's fiscal regime when applied to gas?
- What are the fiscal designs applied by other countries?
- What are the risks and opportunities for international gas suppliers?
- Alaska's Prevailing Fiscal design
- Complications of combined oil and gas progressivity tax (CPT)
- Multi-year and multi-scenario fiscal performance cash flow models
- Conclusions and recommendations

What are the issues for Alaska's fiscal regime when applied to gas?

Alaska is One of Several Potential Long-term Suppliers of Natural Gas to Lower-48 U.S.

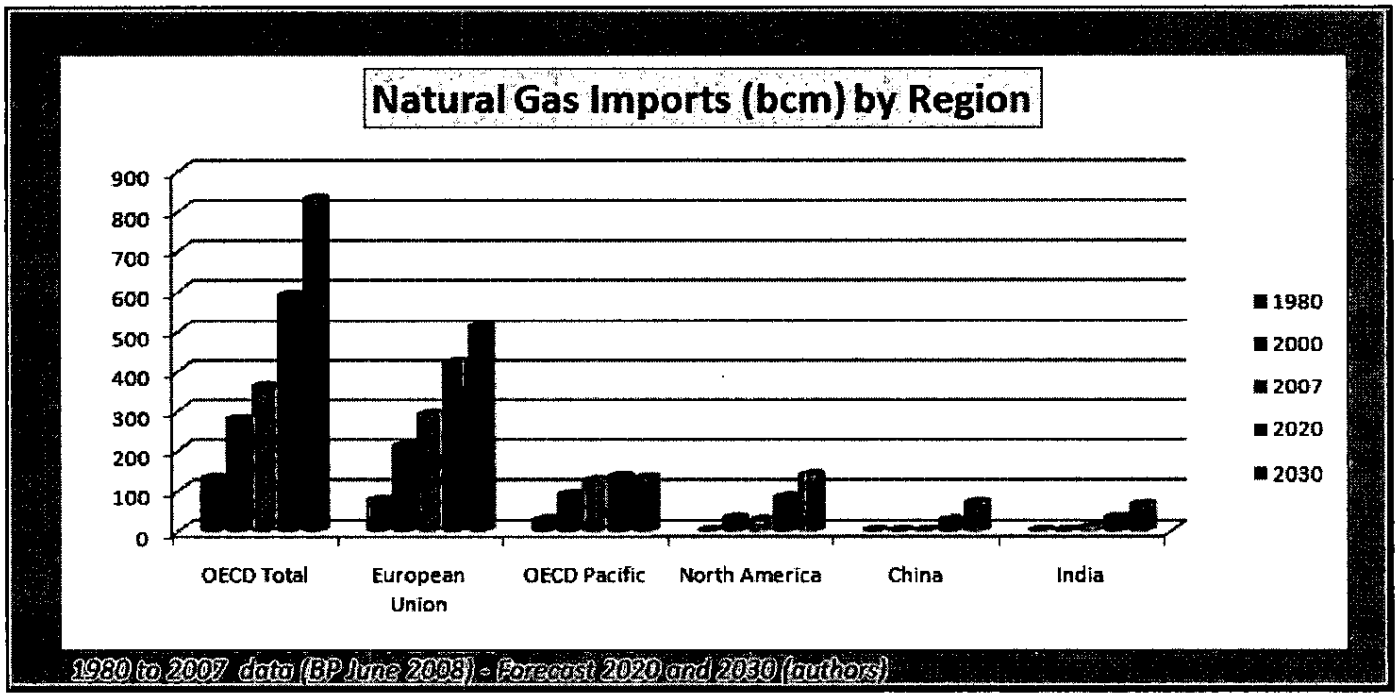


Fiscal terms are one of several factors that influence the delivered price of gas into a market and it is important to understand differences among competing sources.

The differences usually go far beyond a simple percentage sovereign take comparison.

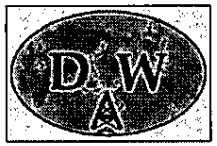
International Gas Markets are Growing - Competition for Gas is Increasing

How key global gas import markets compare and are forecast to grow in absolute terms (bcm = billions cubic metres; 35.3 bcf = 1 bcm).



Michael Economides & David Wood , Journal of Natural Gas Science & Engineering, May 2009

Major IOC's are Signing Long-term Binding International Gas Agreements



Some of the large LNG sale and purchase agreements struck in 2009

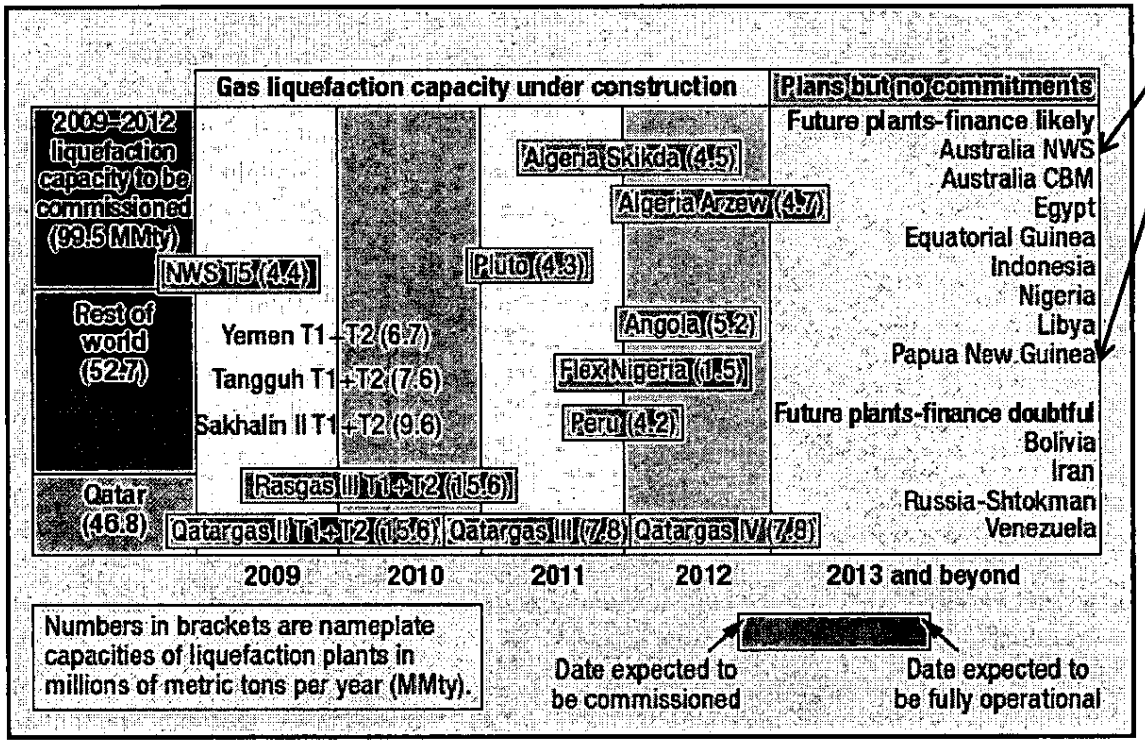
Liquefaction Project	Supplier	Offtaker	Duration, Years	Volume, mtpa	Status	Date Agreed	First Delivery Expected
Gorgon (Australia)	Chevron	Osaka Gas (Japan)	25	1.375	binding	Sept. 2009	2014
Gorgon (Australia)	Chevron	Tokyo Gas (Japan)	25	1.1	binding	Sept. 2009	2014
Gorgon (Australia)	Chevron	Kogas (S.Korea)	15	1.5	HOA	Sept. 2009	2014
Gorgon (Australia)	ExxonMobil	PetroChina (China)	20	2.25	binding	Feb. 2009	2014
Gorgon (Australia)	ExxonMobil	Petronet (India)	20	1.5	binding	May 2009	2014
Wheatstone (Australia)	Chevron	Tepco (Japan)	20	4.1	HOA	Dec. 2009	2016
PNG LNG (Papua New Guinea)	ExxonMobil	Tokyo Gas (Japan)	20	1.8	binding	Dec. 2009	2014
PNG LNG (Papua New Guinea)	ExxonMobil	Osaka Gas (Japan)	20	1.5	binding	Dec. 2009	2014
PNG LNG (Papua New Guinea)	ExxonMobil	Taiwan CPC (Taiwan)	20	.5	HOA	June 2009	2014
PNG LNG (Papua New Guinea)	ExxonMobil	Sinopec (China)	20	2	binding	Dec. 2009	2014
Gladstone (Queensland, Australia)	Santos	Petronas (Malaysia)	20	2	HOA	June 2009	2015
Curtis (Queensland, Australia)	BG	CNOOC (China)	20	3.6	HOA	May 2009	2015
Kitimat (Western Canada)	Kitimat LNG	Gas Natural (Spain)	20	1.6	MOU	July 2009	2013?
Kitimat (Western Canada)	Kitimat LNG	Kogas (S.Korea)	20	2	MOU	June 2009	2013?
Qatargas (Qatar)	Qatargas	CNOOC (China)	Long-term	3	MOU	Nov. 2009	2015?
Qatargas (Qatar)	Qatargas	PetroChina (China)	Long-term	2	MOU	Nov. 2009	2015?

Source: Various media reports

Published by David Wood, World Oil, Feb 2010

Worldwide New Gas Liquefaction Developments to 2013 and Beyond

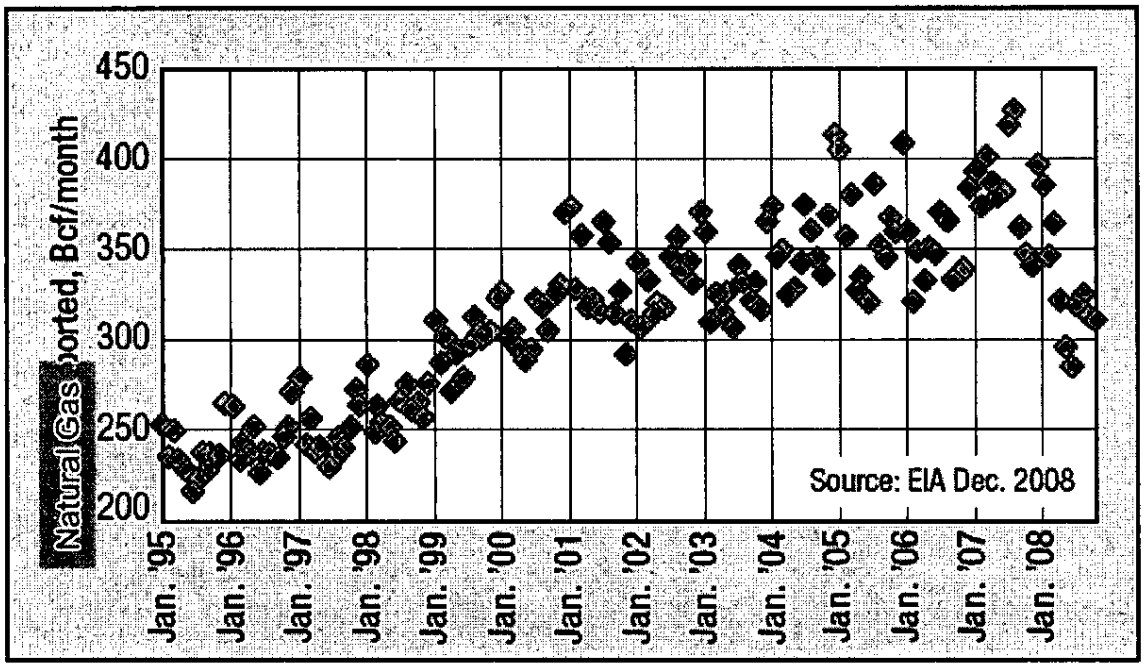
Large new capacity of LNG coming into the market with new plants under construction. Big commitments for new plants in Australasia made progress in 2009.



From David Wood *"Uncertain supply and demand outlook for LNG."* **World Oil** (February 2009)

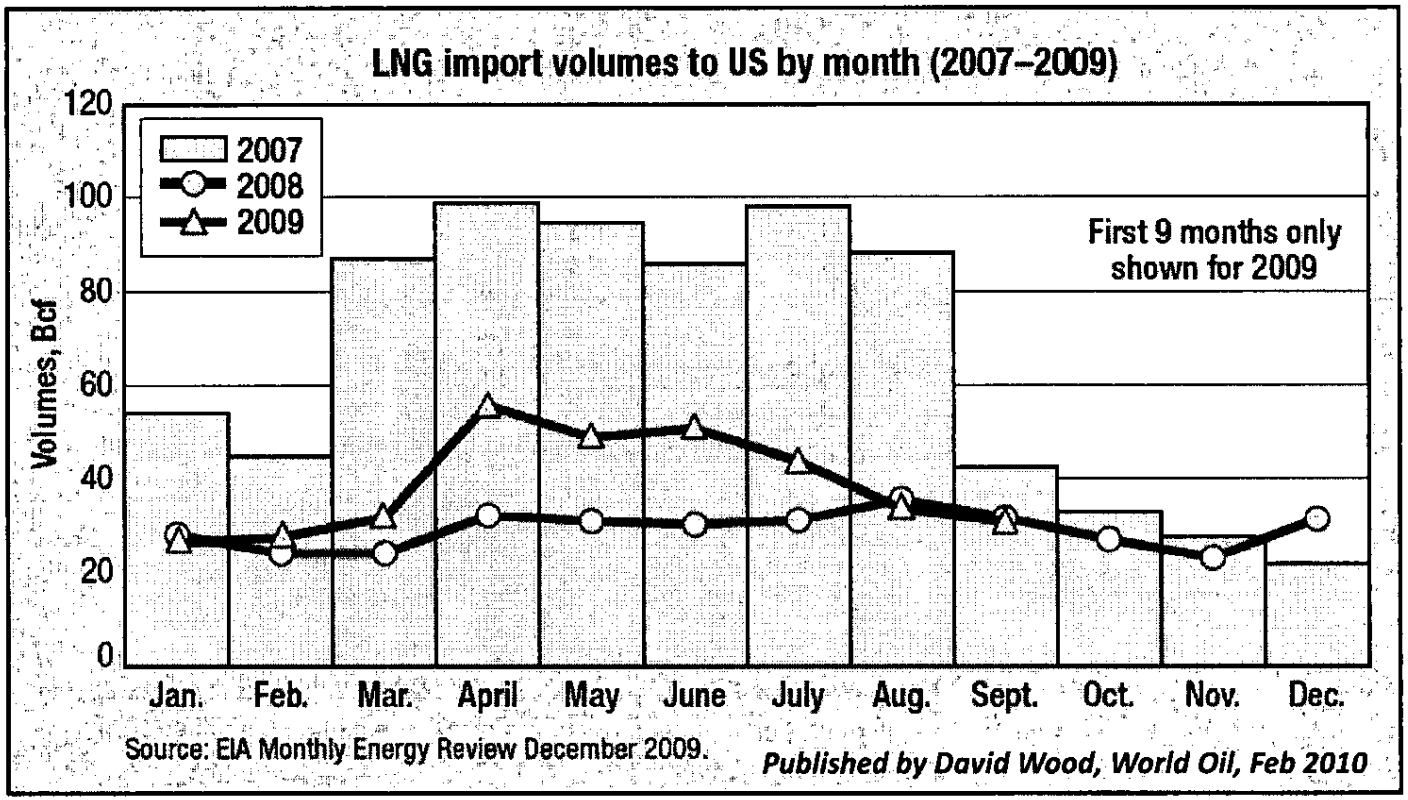
Gas Imports to U.S. Decline in 2008 For First Time in More than a Decade

Greater Lower-48 gas production in 2008, particularly shale gas, led to a reduction in US gas imports which has persisted. Alaska gas will be competing with shale gas for lower-48 which has a different resource and cost base and fiscal structure.

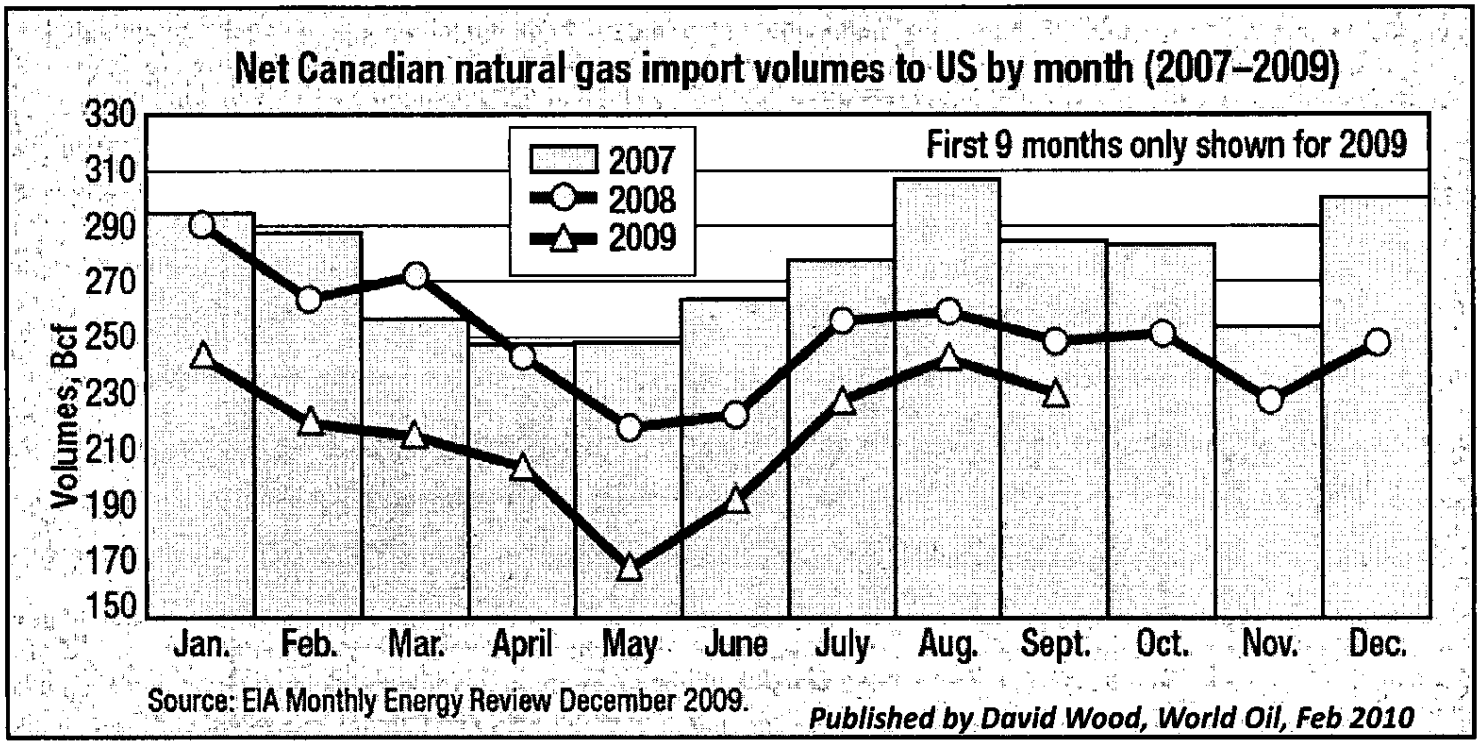


From David Wood *"Uncertain supply and demand outlook for LNG."* **World Oil** (February 2009)

LNG Imports to U.S. are Down
Is that Permanent? Shale Gas Effect?

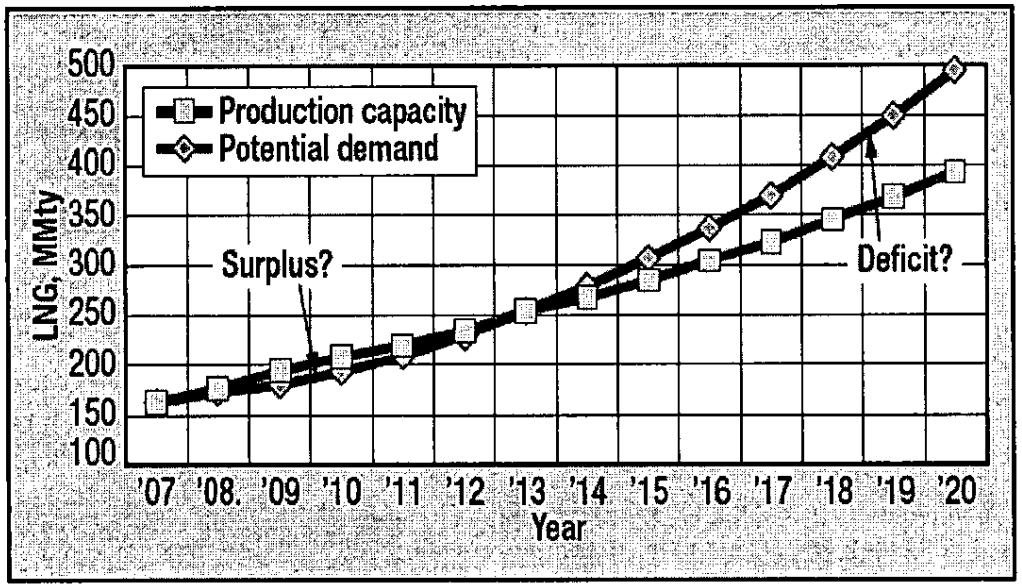


Canadian Gas Imports to U.S. are Down
Is that Permanent? Shale Gas Effect?



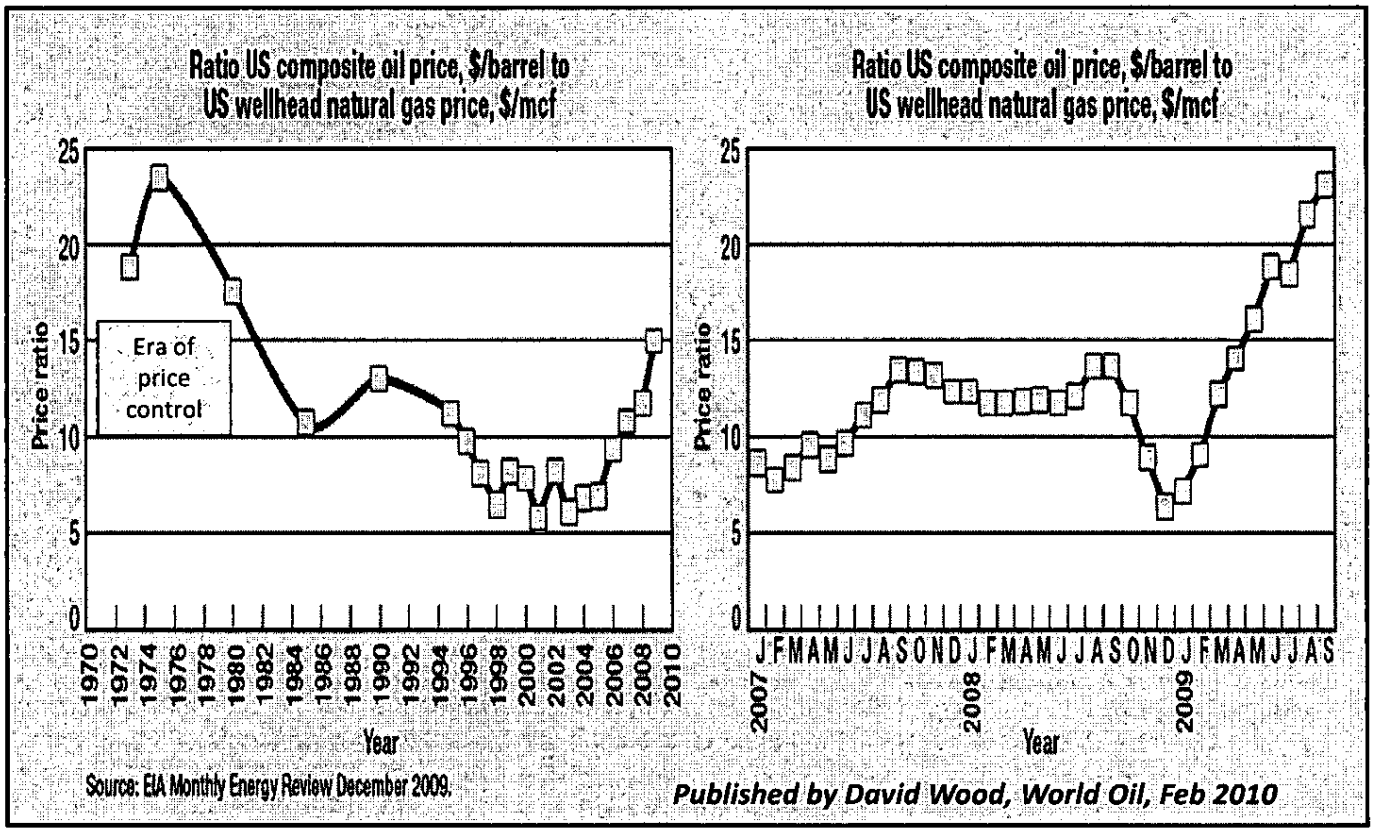
Global LNG Supply Demand Forecast to 2020

Natural gas surplus due to economic downturn and development of competing supplies is leading to over-supply and lower prices forecast to last perhaps to 2012 for internationally traded LNG. This surplus may itself fuel supply shortfalls globally beyond 2013 and higher prices 2015 to 2020.



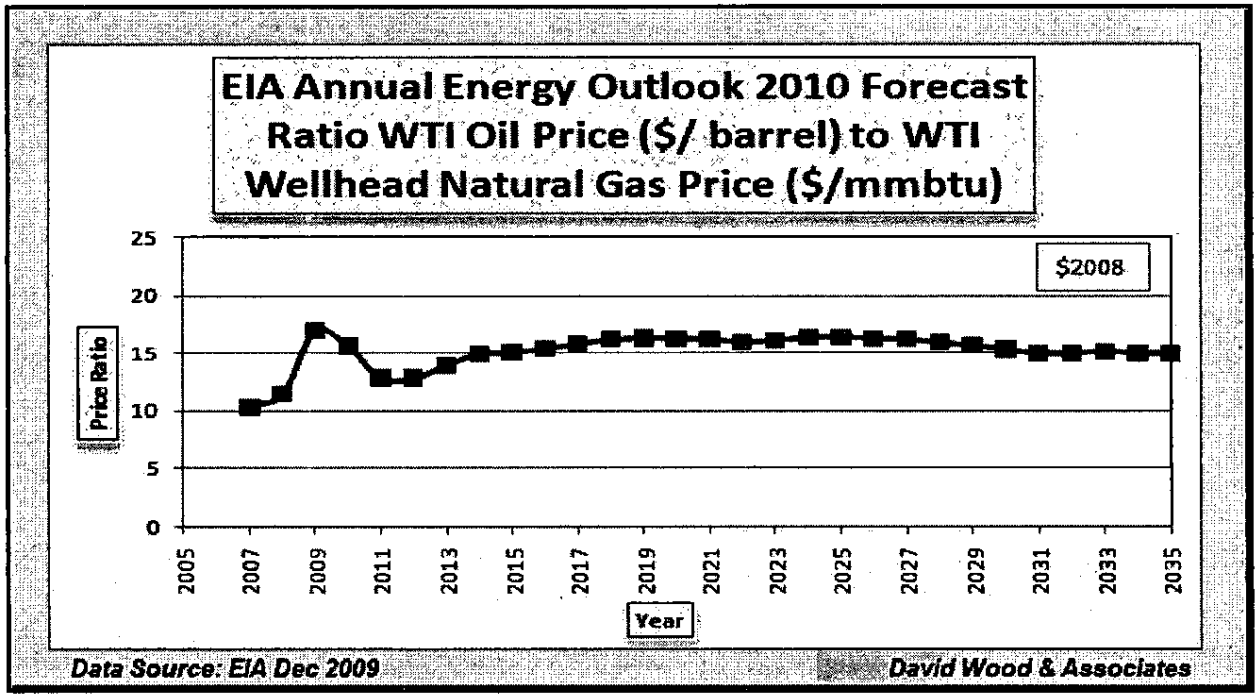
From David Wood *"Uncertain supply and demand outlook for LNG."* **World Oil** (February 2009).

U.S. Oil to Gas Price Ratio
What Range Should Fiscal Designs Consider?



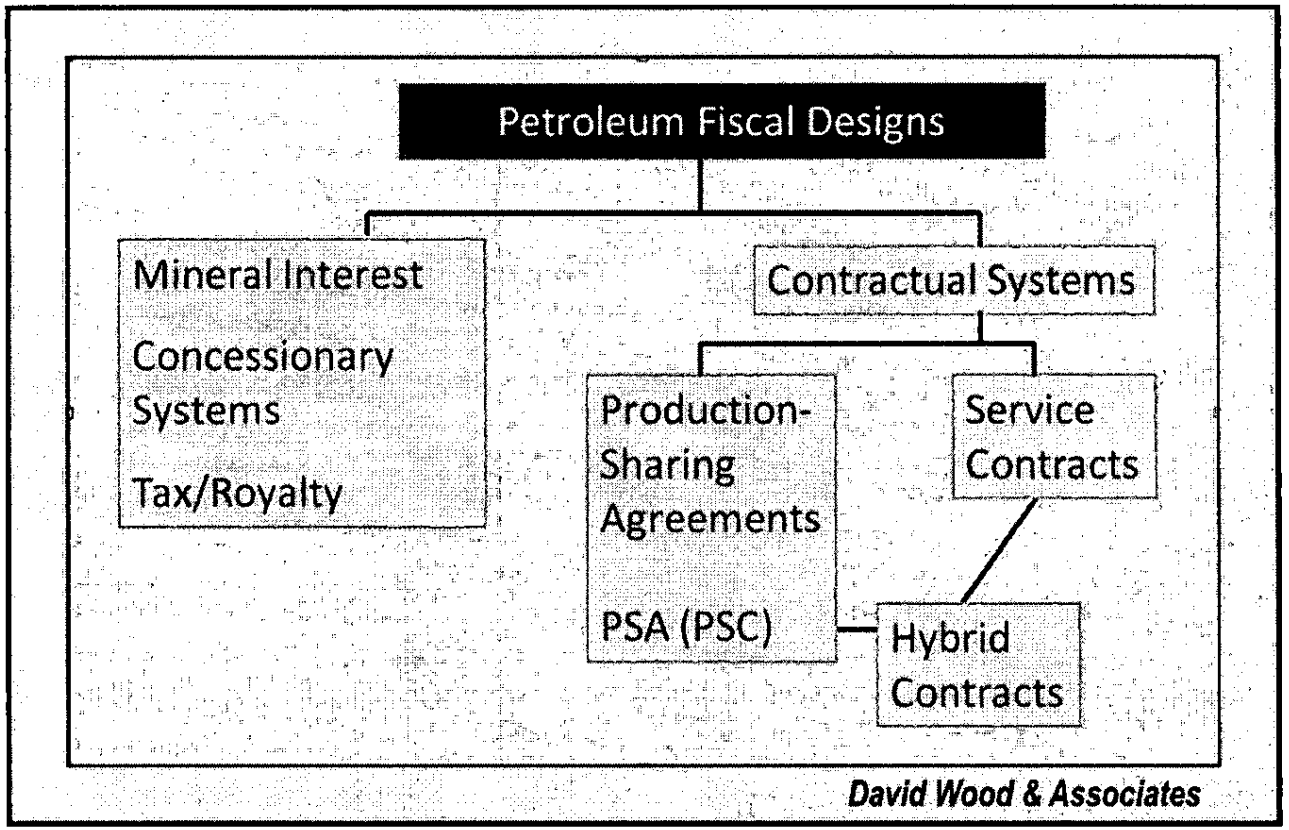
Latest U.S. Government Forecast Shows High Oil to Gas Price Ratios Through to 2035

Fiscal designs should be stable under a wide range of oil: gas price ratios (e.g. stress test them with ratios of 2 to 30).

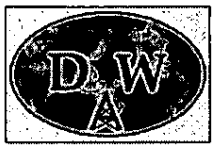


What are the fiscal designs applied by other countries? and what are the risks and opportunities?

Summary of International Upstream Oil & Gas Fiscal Designs



Norway:
Fiscal Terms Summary



Norway operates a mineral interest system. There are no bonuses or royalties and the fiscal take comes from *progressive* instruments.

- Royalty 0% and no bonuses but marginal tax burden is some 78%
- Corporate Tax (CT) 28% of taxable income
- No ring fences with CT base established at the company Level.
- Special tax rate 50% with investment uplift of 7.5% for 4 years deducted from CT base. Uplift shelters marginal fields.
- Tax of CO_2 emissions at 0.79 NOK (~10 US cents)/ m^3 CO_2
- Gas taxed on bases of actual realised prices.
- Strict rules applied concerning prices of gas transfer between affiliates.
- Stated fiscal strategy is *that the tax system should act as a sleeping partner providing producers with technical control and ensuring that any investment decision that is commercially viable before tax should remain viable after tax.*
- This system secures high fiscal takes for the government (close to 80%), but has still attracted large and small international investors.
- State is actively involved as an equity participant through its NOC (Statoil).

Papua New Guinea (PNG): Fiscal Terms Summary

Papua New Guinea (PNG) operates a mineral interest system. It has relaxed fiscal terms since 1990's as fields under development have declined. Upsurge in interest in large LNG projects led to legislative changes offering progressivity and stability.

- Royalty 2%
- Income tax (IT) 30% for gas (50% for oil)
- Additional Profits Tax (APT) 7.5% after 17.5% post-IT IRR reached for project and 10% after 20% post-IT IRR reached for project.
- State equity participation 22.5% (2% of which goes to landowners)
- Partial carry for the state
- Past exploration costs recoverable through 20-year carry-forwards
- Marginal field incentives: e.g. accelerated depreciation
- ExxonMobil (41.6%) and partners completing FEED studies and a final investment decision for PNG LNG is expected in 2010
- Long-term gas buyers in China and Japan now secured.

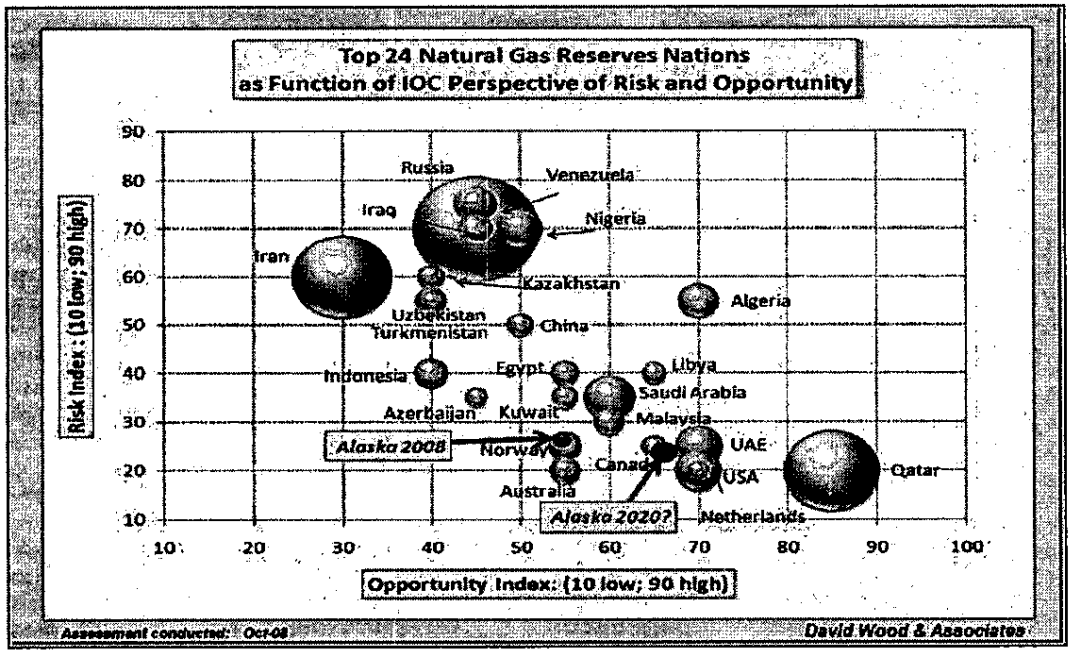
Australia:
Gas Fiscal Terms Summary

Australia operates a mineral interest system. Its fiscal take is above 70% and comparable to that of Alaska, but it is much more successful at securing investment and buyers for its high cost isolated gas resources.

- Australia has progressively shifted from traditional volume based royalty arrangements to the more progressive petroleum resource rent tax (PRRT)
- PRRT is levied at a rate of 40% of a project's taxable profit.
- PRRT payments are deductible for company income tax rate of 30%.
- PRRT is only payable once project cash flow basis achieves a rate of return of 5% over the long term bond rate on the development investments and 15% rate of return over the long term bond rate on exploration or risk capital investment. [This limit and cost uplift prevent PRRT becoming regressive]
- Explorations costs are uplifted at 15% (other costs uplifted at 5%) above long-term bond rate to partially compensate for time-value issues as there is a long lead time from discovery to positive cash flow.
- IOC majors committed in excess of $20 bn investment in LNG projects in 2009.
- Long-term gas buyers in China and Japan now secured.

Alaska Gas Compared on International Scale of Risk versus Opportunity

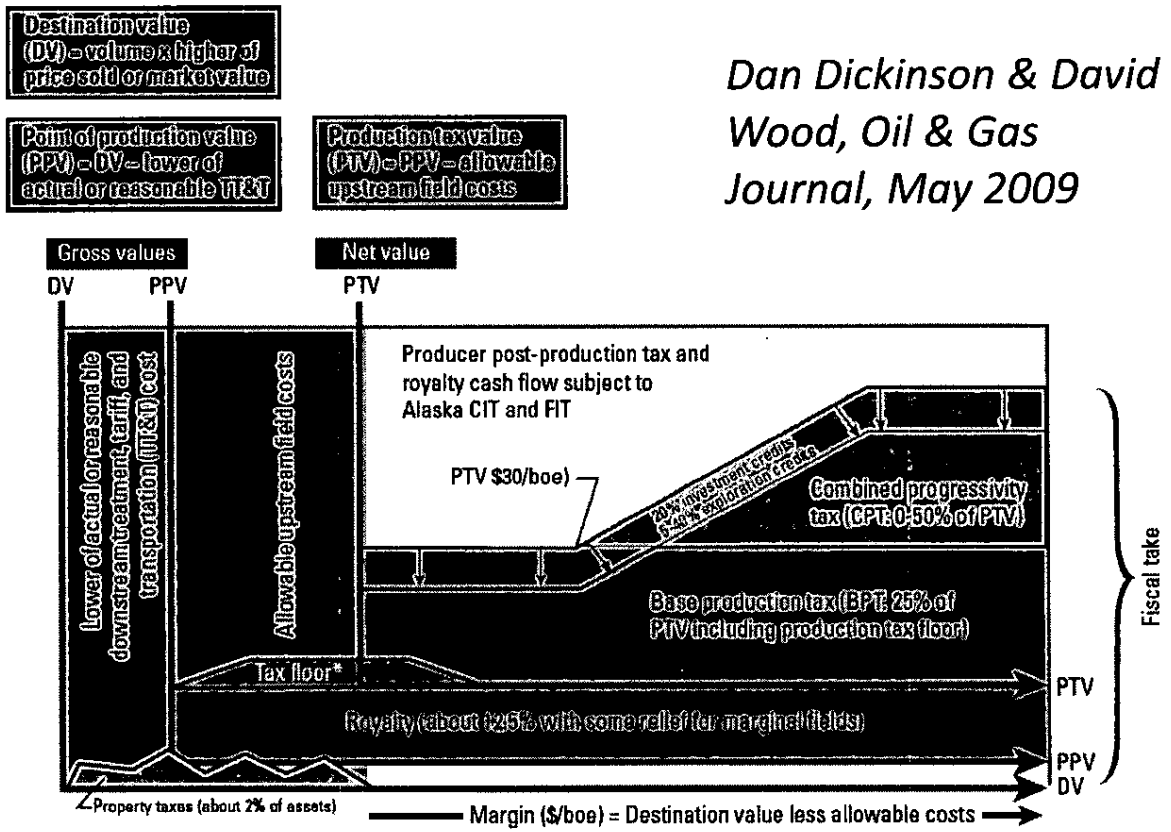
The diameters of the bubbles are proportional to proved natural gas reserve holdings as reported by BP Statistical Review (June 2008).



Alaska marked on the framework from David Wood *"Global perspectives required for risk, opportunity analyses."* **Oil & Gas Journal** (9Feb, 2009).

Alaska's Prevailing Fiscal design

Schematic of Alaska's Prevailing Oil & Gas Fiscal Design



Dan Dickinson & David Wood, Oil & Gas Journal, May 2009

Regressive & Progressive Elements of Alaska's Prevailing Oil & Gas Fiscal Design

Regressive fiscal elements	Progressive fiscal elements
• Property taxes are levied on assets in theupstream orTT&T services and shared between the state and local governments • Royalty is levied at point of production value (PPV) • *Tax floor refers to a production floor levied at 0-4% of PPV in place of BPT when that floor value is higher than the BPT value	• Production taxes (BPT and CPT) are taxes paid on net value or margin • Progressivity component of production tax (CPT) commences at PTV of $30/boe • Alaska corporate income tax (CIT) of 9.4% is levied on producer's worldwide income apportioned to Alaska. CIT is deductible from federal income tax (FIT)

Dan Dickinson & David Wood, Oil & Gas Journal, May 2009

Key Regressive Elements in Alaska's Prevailing Fiscal Design

There are three elements that make Alaska's prevailing fiscal design regressive.

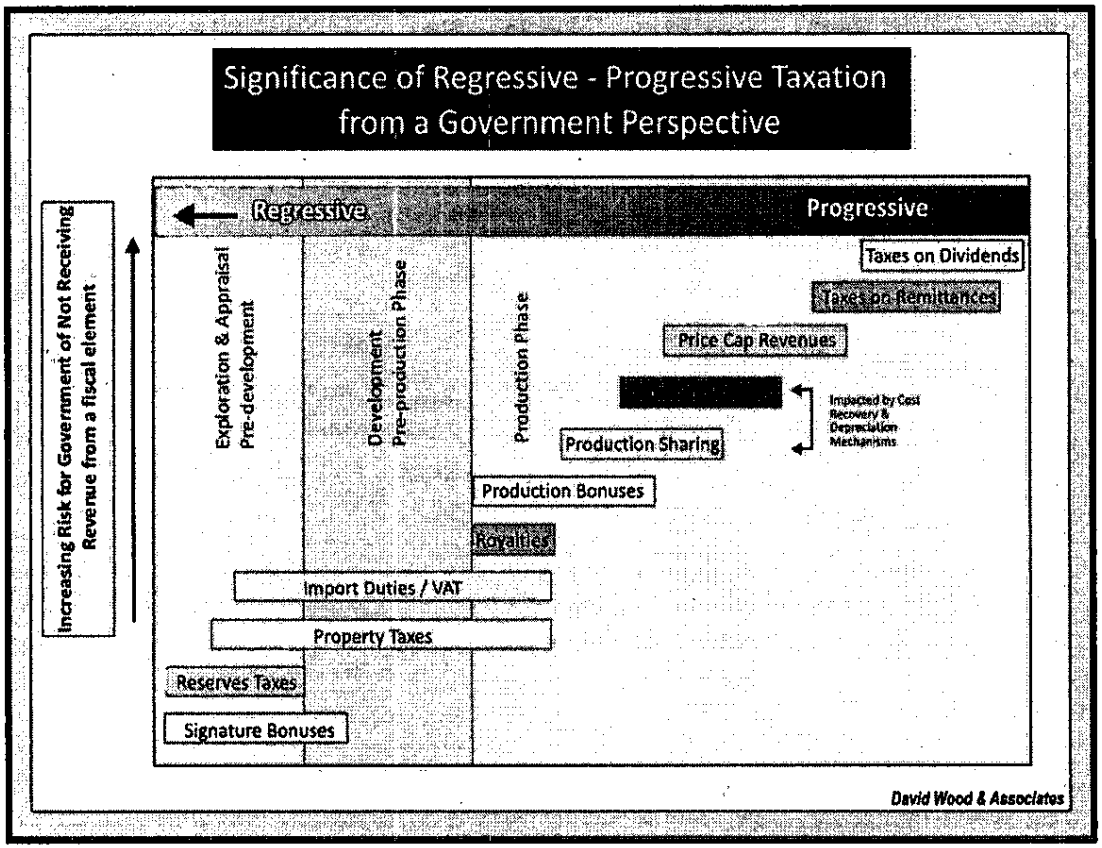
- Royalty
- Property Taxes
- Production Tax Floor

These regressive elements are partially offset by:

- Investment credits (exploration and development)
- Production taxes (levied after deduction of all allowable costs)
- Progressivity tax (only levied on high value streams)

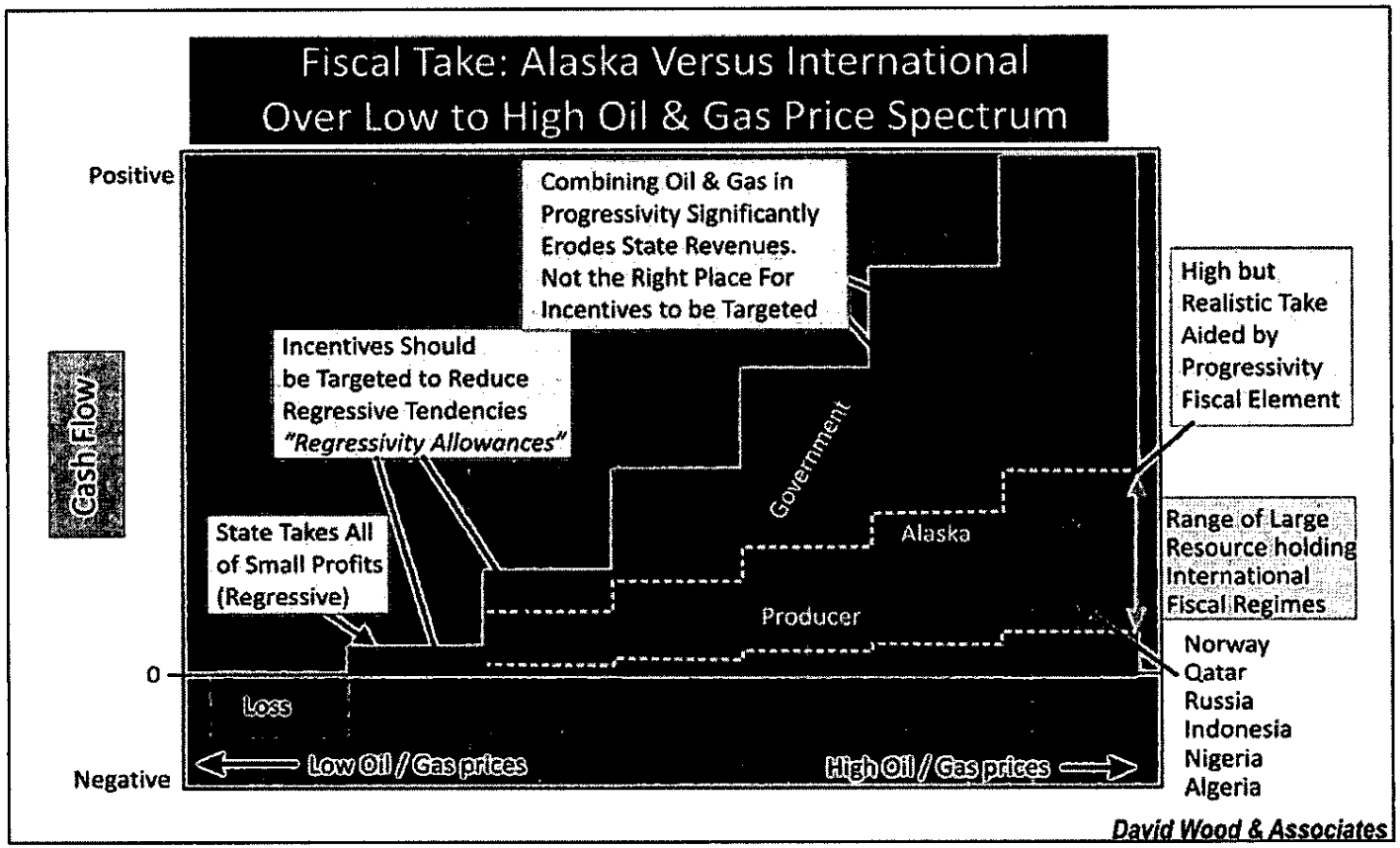
Other allowances / credits for producers should be considered to offset impacts of regressive elements coupled with tougher progressivity terms.

Progressive & Flexible Fiscal Designs Help to Promote Investment



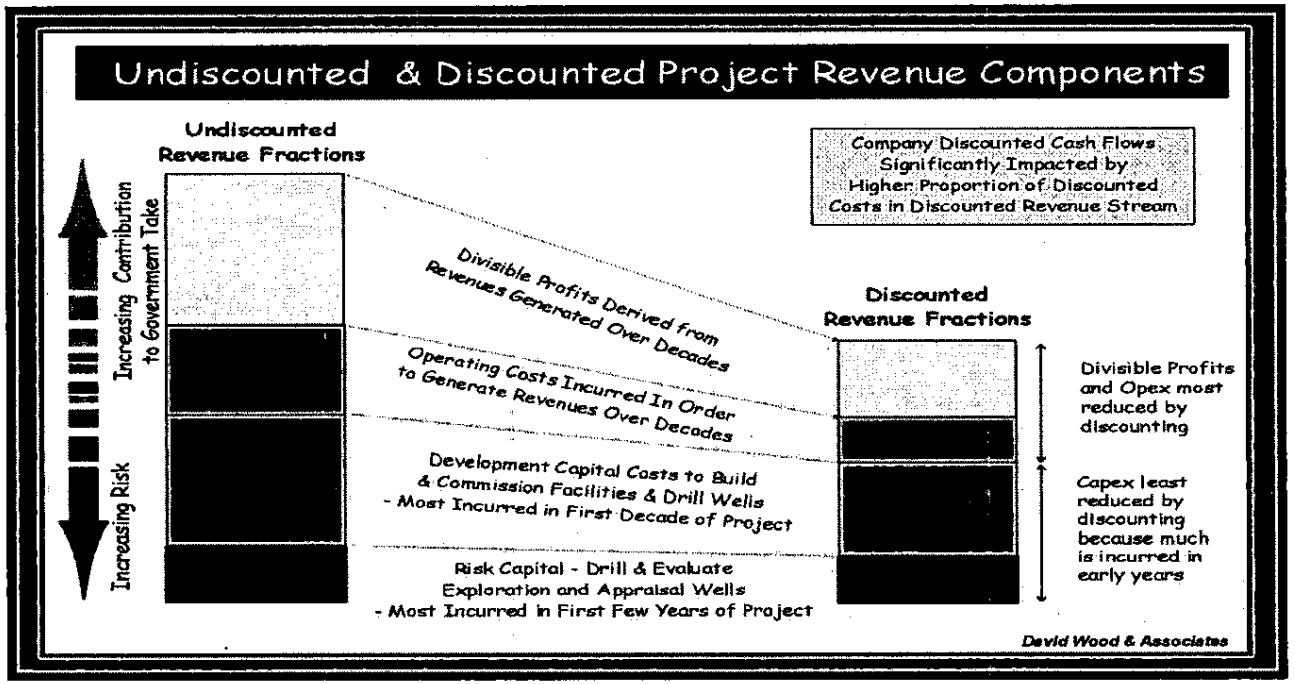
The stronger the commitment made by governments to promote a commercially attractive environment, the more likely investors are to commit investments without guarantees of fiscal stability.

Progressivity Should Work Well For Alaska: It's the Regressive Elements that Need Relief



High Discount Rates Suggest Higher Government Take of Revenues

It is appropriate for governments to use lower discount rates than producers. However, high discount rates impact *long-term* divisible profits and operating costs more than upfront capital costs so diminish producer take.



Complications of combined oil and gas progressivity tax (CPT)

Problems with Alaska's Current Progressivity Tax from the Natural Gas Perspective

The models of a wide range of gas field sizes suggest three issues associated with calculating production tax values using a combined oil and gas (boe) revenue stream.

- Large gas production volumes contributing low value to high value oil production can dilute the PTV/boe and progressivity of the combined stream.
- The PTV / boe threshold (i.e., trigger point) at which progressivity tax becomes initially payable are set too high for natural gas.
- Tying the production tax floor to PPV can lead to regressive consequences for gas producers in high cost / low value conditions.

Impact of Natural Gas on Combined Oil & Gas Production Tax

Analysis has identified that three factors are relevant to the dilution effects under prevailing production tax paid by an existing oil- only case with the addition of gas production (and vice versa – i.e. oil added to a gas-only case). These factors are:

1. Magnitude of value differential between oil and gas streams (high oil value minus low gas value, or high gas value minus low oil value);

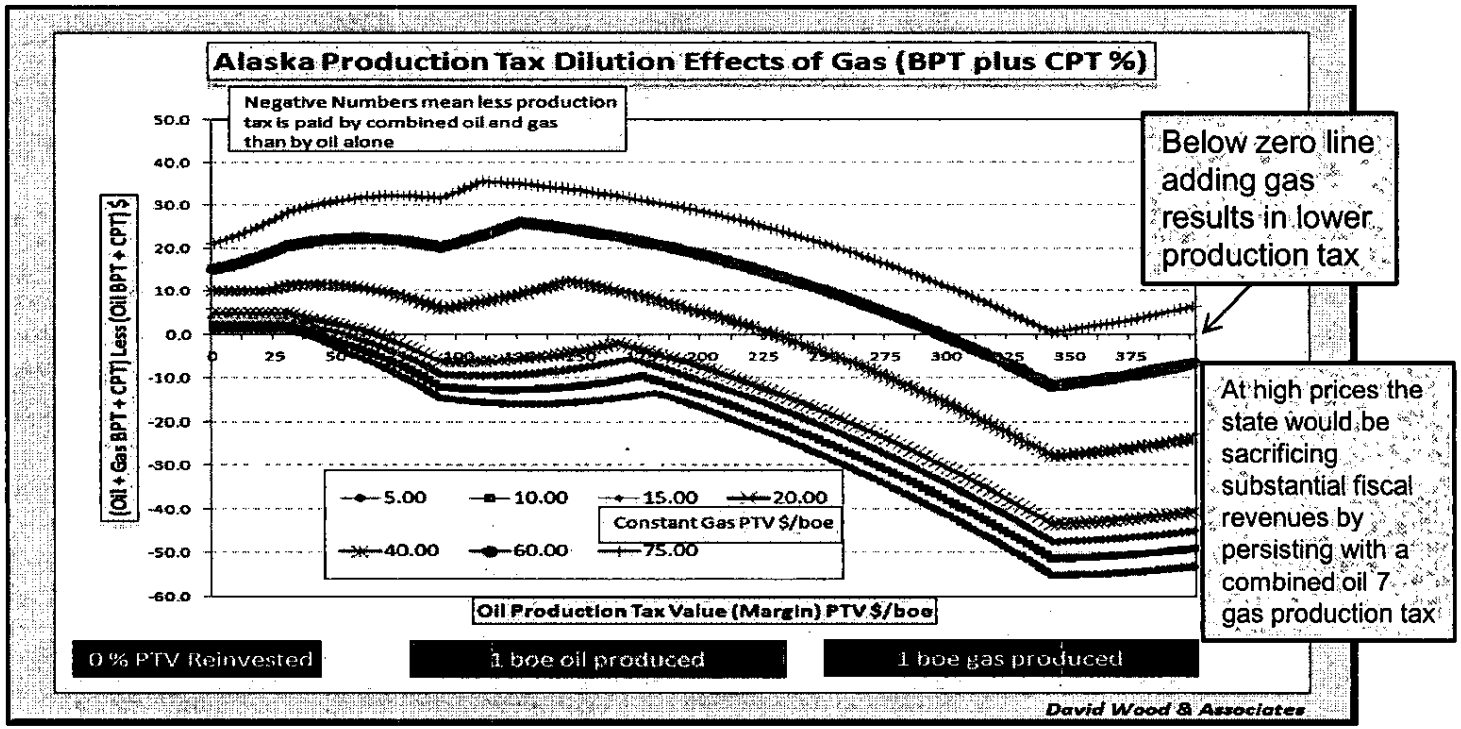
2. Relative volumes of oil and gas produced contributing to combined production tax boe stream.

3. Amount of PTV reinvested, which depending on the PTVs of each stream can have a significant impact

An Excel computer model has been developed to test these three factors.

Natural Gas Dilution Effects on Combined Oil & Gas Production Tax

The trends are non-linear with slope changes because of the changing gradients of the production tax progressivity mechanism (i.e. 0.4/boe to 0.1/boe) and the threshold values at which those changes occur.



DOR High-level Model Adjusted To Calculate Oil & Gas Combined as BOE

The Department of Revenue (DOR) model presented on 22 Feb 2010 has been reviewed and tested for functionality . With a few minor corrections and modifications to this model can be made to calculate 1 boe rather than 1 barrel by adding inputs for:

	One BOE Comparison of Current to Modified				
14.17	Natural Gas Destination Price $/mmbtu	6	Oil:Gas Price (Parity X:1)		
	Modifications - $ Per Barrel				Oil:Gas Parity Fraction Macro DW
0.5	Fraction of Natural Gas to Oil in boe production			generic mmbtu/boe:	6
24.0	Gas Transport Cost $/boe				
	Item	Current $/boe	Modified $/boe	Difference $/boe	
85	**Base Case Oil Price**				
	Determining the per barrel taxable value at the point of production				
85	Boe Destination Price (Oil:Gas Mix)	$85.00	$85.00	$0.00	Destination prices for crude and gas
7	Less Transportation Cost (oil:gas mix)	$15.50	$15.50	$0.00	For oil = TAPS tariff plus shipping
	Gross Value at Point of Production	$69.50	$69.50	$0.00	
0.125	Royalty	$8.69	$8.69	$0.00	By lease with 12.5% most common
16.26	Less Upstream Costs	$16.26	$16.26	$0.00	Opex plus Capex
	Production Tax Value (PTV)	$44.55	$44.55	$0.00	
	Taxable Barrels (1-royalty %)	0.875	0.875	$0.00	
	PTV / taxable bbl	**$50.92**	**$50.92**	$0.00	Gross Up Production

Modifications Made to DOR Model to Calculate BOE

- (A) Oil: Gas Price Parity (Cell C3) and used that to calculate a gas price ($ mmbtu) (cell A3)
- (B) Gas: Oil fraction per boe of production (cell A5)
- (C) Gas transportation cost (Cell A6)
- (D) The defined 6 mmbtu per boe from ACES (Cell F5)

These inputs are then used to recalculate:

- A boe destination price in cells C10 and D10 (rather than just oil price in DOR version)
- A boe transportation cost in cells C11 and D11 (rather than just oil price in DOR version)

Note: By setting A = 6 and B=0 the rest of the workbook calculates as it was presented by DOR (with corrections mentioned above). I have not reformatted the sheet but left it as per DOR's layout.

Case Combinations Evaluated with Modified DOR High-level Model

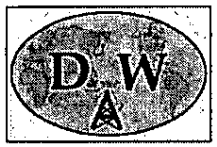
Variables		
Oil Price $/barrel	Oil: Gas Price Parity (X:1)	Fraction Gas: Oil (0 to 1)
20	2	0.0
40	4	0.1
60	6	0.2
80	8	0.3
100	10	0.4
120	12	0.5
140	14	0.6
160	16	0.7
180	18	0.8
200	20	0.9
300	30	1.0
Base Case		
85	6	0.5

In this modified form the workbook can be used to model the impacts of oil and gas streams of various proportions and price parities using DOR's high-level Alaska tax methodology.

The input data for the three key variables used can be varied by changing the values in the new table located in cell range C46:E60, which can be set to a user's preference.

A macro then evaluates and records selected outputs for all oil and gas scenarios.

Macro Calculates Large Number of Price Parity and Gas Fraction Cases Rapidly

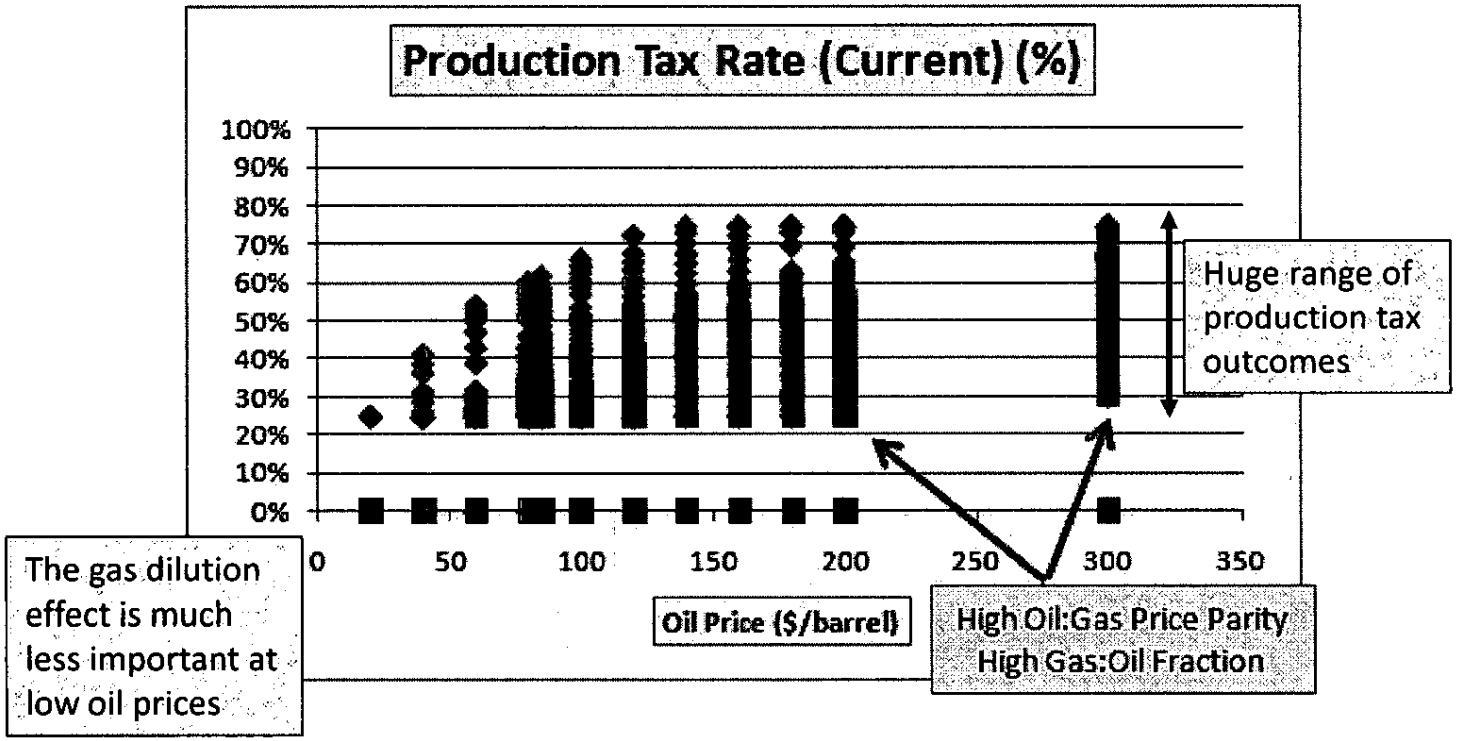


For the 12 X 12 X 12 input matrix the macro calculates 1728 values for each output variable recorded (more than 20000 values for 12 variables recorded). The macro places the recorded data into a table for analysis.

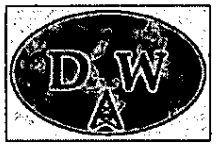
- For current and modified terms the macro records:
  - Production Tax Rate % from cell C25 on sheet Calc
  - Production Tax Value $/boe from cell C29 on sheet Calc
  - Producer's Take Rate from cell C42 on sheet Calc
  - Producer's Total Value $/boe from cell C37 on sheet Calc
  - State Take Rate % from cell C39 on sheet Calc
  - State Total Value $/boe from cell C33 on sheet Calc

Production Tax Rate Analysis for 1728
Macro Scenarios for Combining Oil and Gas

The red squares are the cases in which oil:gas price parity is >10 and gas:oil fraction of production mix is >0.5 on a boe basis.



Conclusions from Combined Oil & Gas Production Tax Model

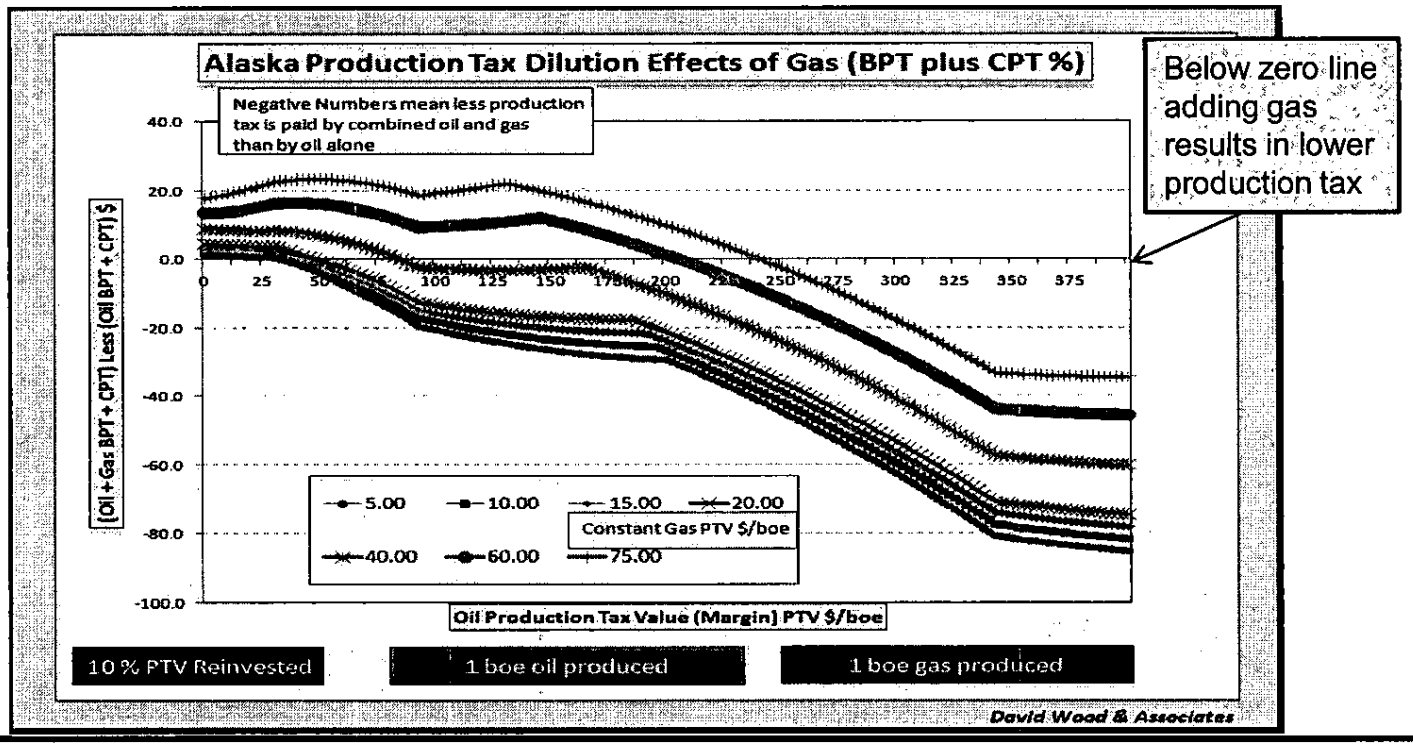


For the 12 X 12 X 12 input matrix the macro calculates 1728 values for each output variable recorded (more than 20000 values for 12 variables recorded). The macro places the recorded data into a table for analysis.

- It would be more stable to calculate Alaska's oil and gas production taxes separately and avoid boe complications particularly as oil : gas price ratio is unpredictable
- The dilution effect of gas should not be treated as a fiscal incentive as it is unpredictable in its impact
- Significant fiscal benefits of occasional price spikes on high production tax for gas or oil could be lost by persisting with a boe basis or combined calculation of the production tax value.

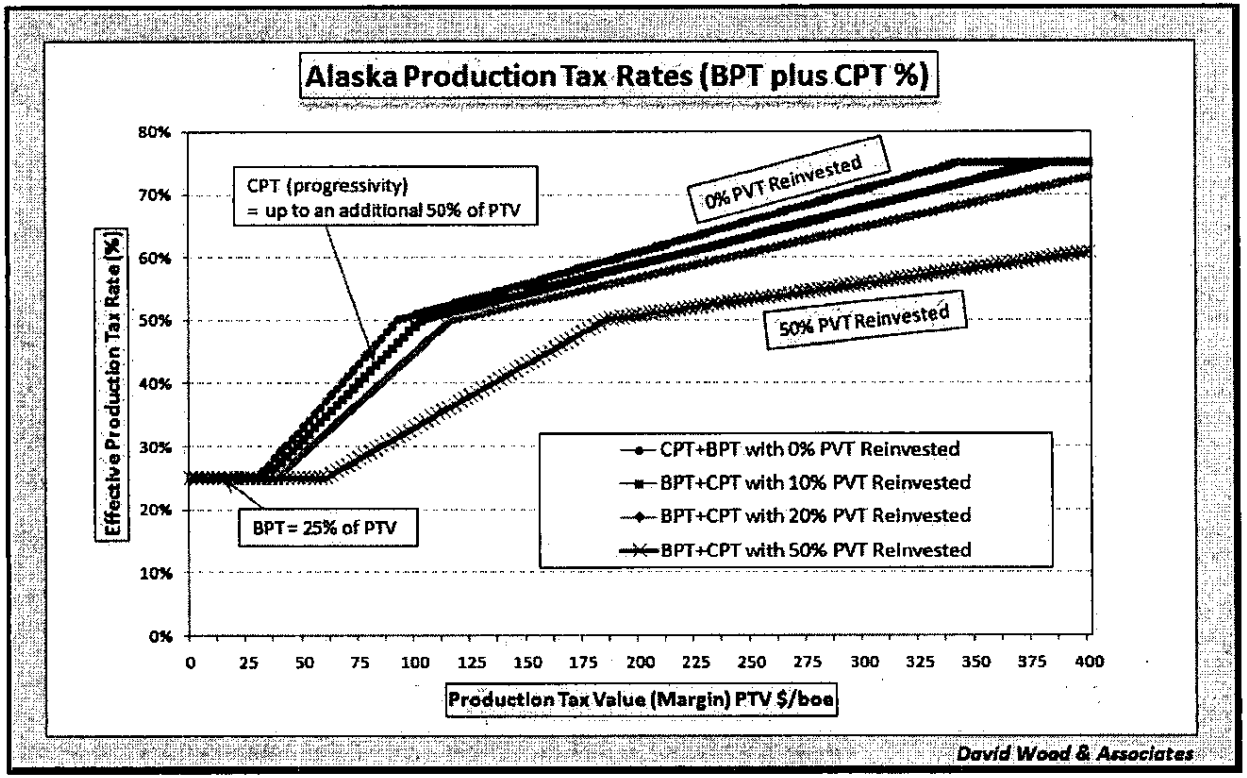
Natural Gas Production Tax Dilution Effects Impacted by Reinvestment

If some of the PTV is reinvested the reduction in production tax paid is significantly greater. This graph shows the impact of 10% reinvestment. [Model results presented in January 2009].



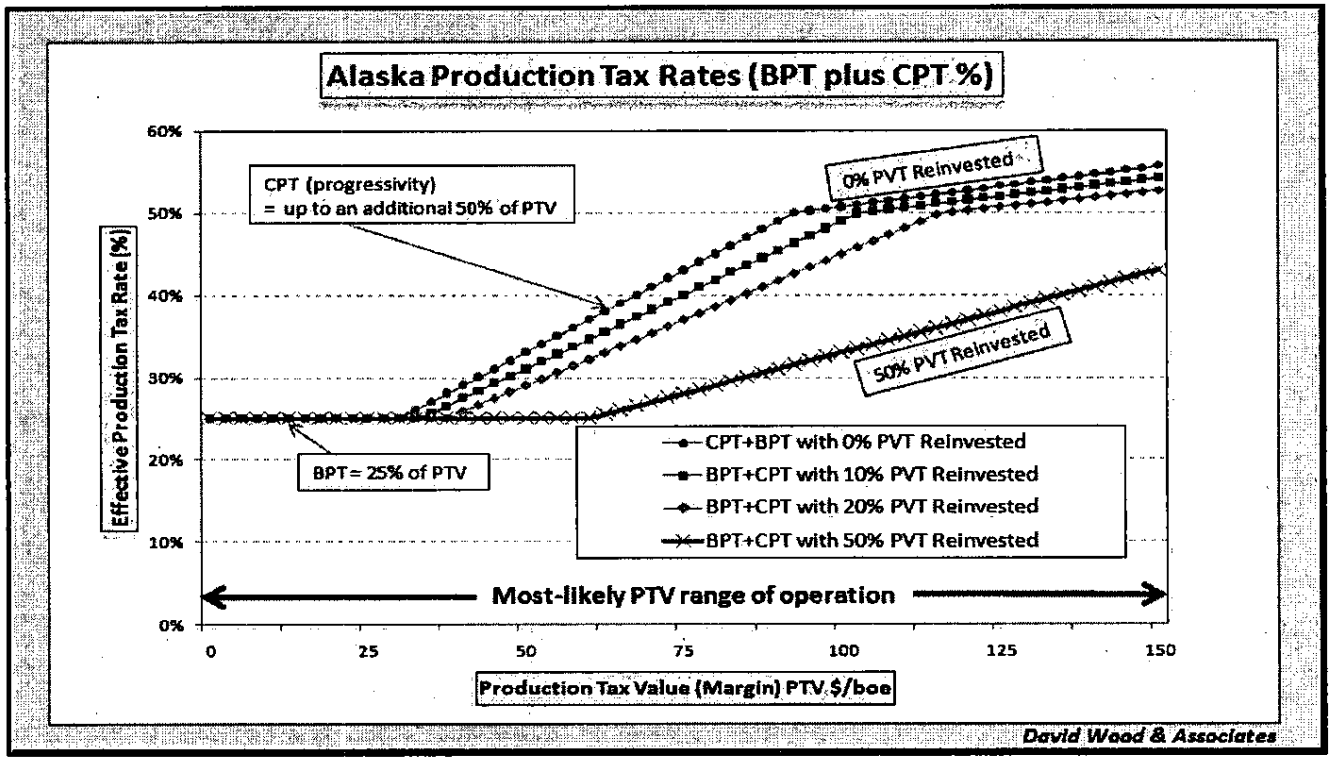
Natural Gas Production Tax Dilution Different Reinvestment Scenarios

The impact of several reinvestment scenarios – 0% , 10%, 20% and 50% of PTV - on production tax rates are illustrated in this graphic.



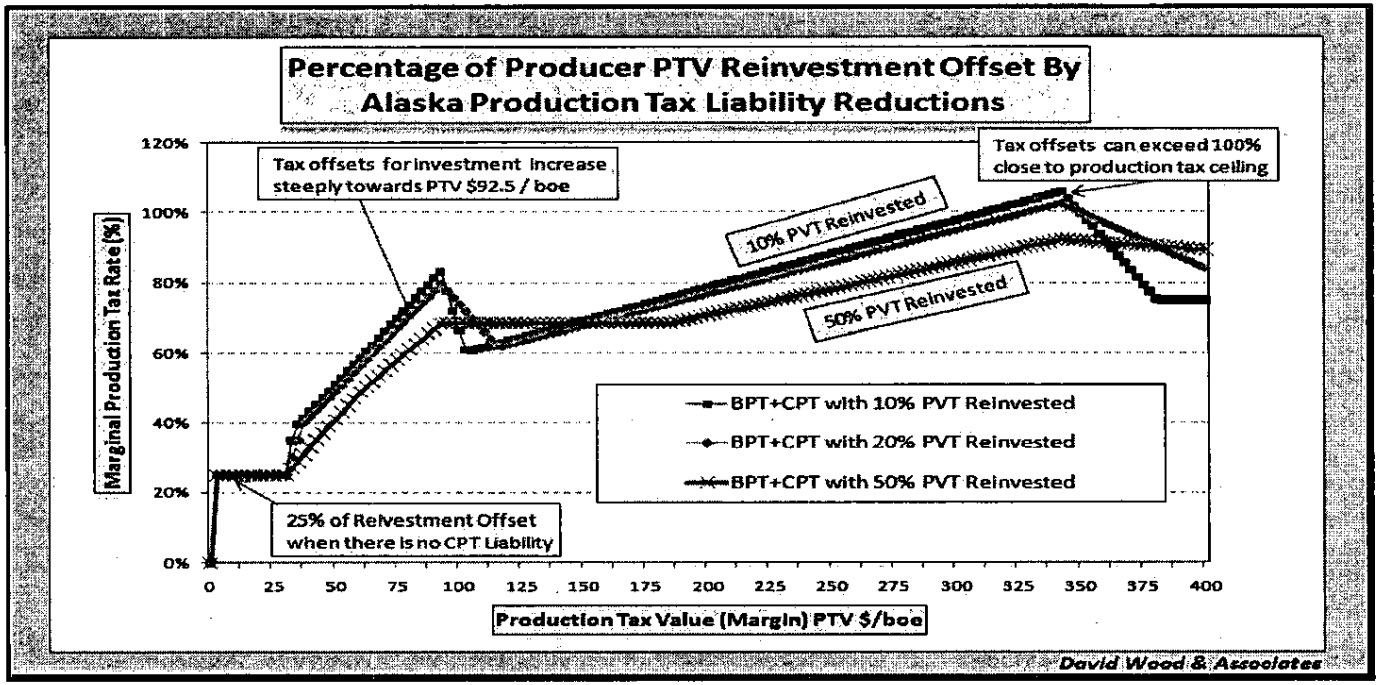
Reinvestment Scenarios For PTV Range $30/boe to $150/boe

For example production tax rate can be reduced from 49% to 42% at PTV $90/boe by reinvesting 20% of the PTV.

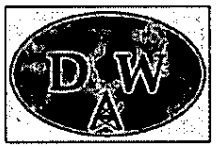


Marginal Production Tax Rates Seen by a Producer for Reinvestment Dollars

The vertical axis shows the percentage tax reduction associated with the incremental re-investment (or the marginal tax rate offset by the producer by its reinvestment). Note the peak around PTV$90/boe and values above 100% at PTV $350/boe plus multiple crossover points.



Implications of Combined Oil & Gas Production Tax Analysis

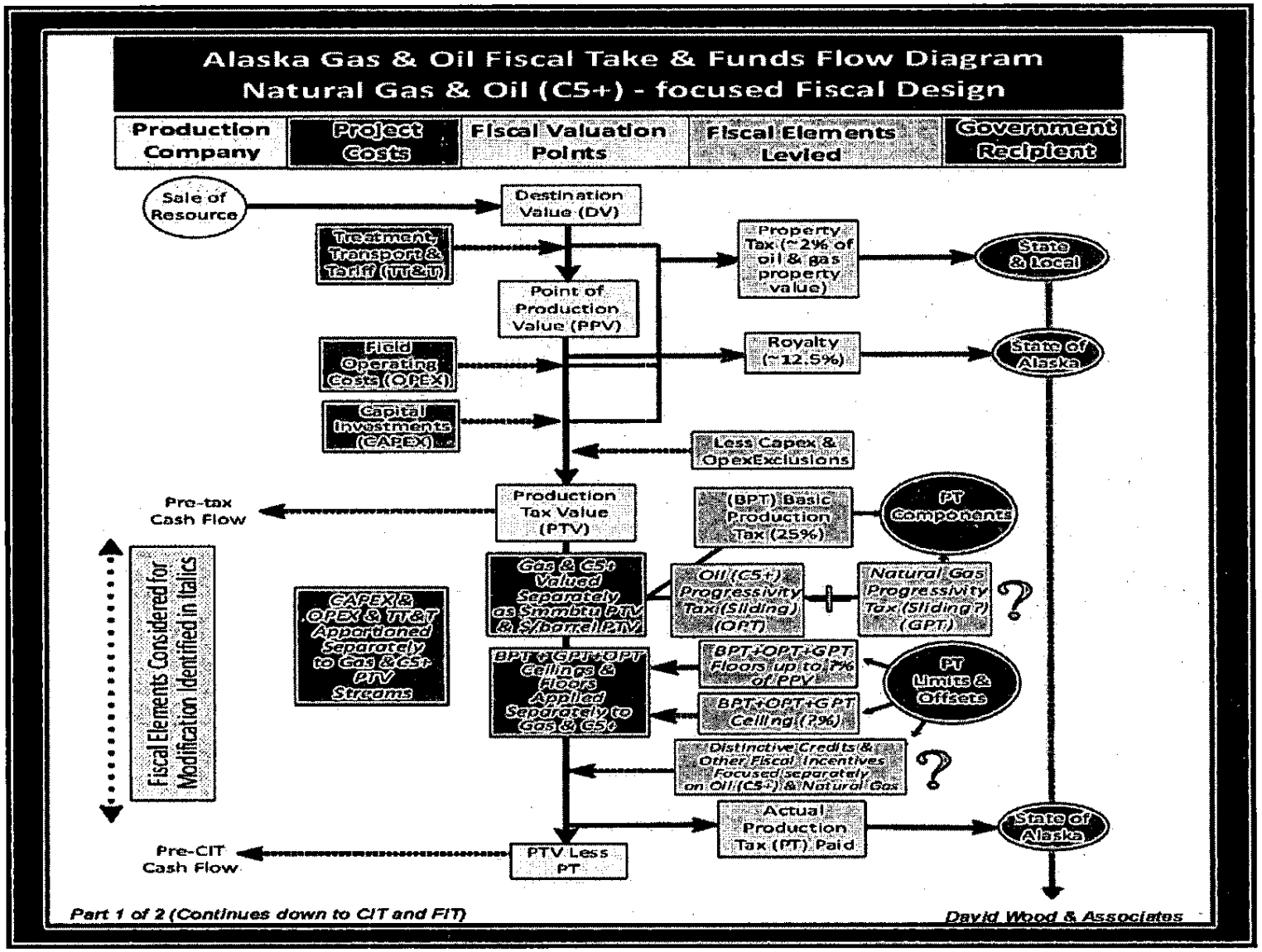


The analysis suggests that the prevailing production tax system has the following complications to address:

1. It is difficult to predict (from tax authority & producer perspectives) and relationships between oil and gas tax liabilities are non-linear;

2. The magnitude of the combined production tax impact caused by adding a gas production stream varies with relative oil and gas PTVs, oil and gas volumes and percentage of PTV re-invested;

3. Without detailed analysis (and speculative forecasting of oil and gas prices and boe contributions) Alaska's production tax outcomes can be counterintuitive (e.g. higher prices can lead to lower tax revenues collected by the State in some scenarios).


Alaska Gas & Oil Fiscal Take & Funds Flow Diagram
Natural Gas & Oil (C5+) - focused Fiscal Design
Production Company
Project Costs
Fiscal Valuation Points
Fiscal Elements Levied
Government Recipient
Sale of Resource
Destination Value (DV)
Treatment, Transport & Tariff (TT&T)
Property Tax (~2% of oil & gas property value)
State & Local
Point of Production Value (PPV)
Field Operating Costs (OPEX)
Royalty (~12.5%)
State of Alaska
Capital Investments (CAPEX)
Less Capex & OpexExclusions
Pre-tax Cash Flow
Production Tax Value (PTV)
(BPT) Basic Production Tax (25%)
PT Components
Gas & C5+ Valued Separately as $/mmbtu PTV & $/barrel PTV
Oil (C5+) Progressivity Tax (Sliding) (OPT)
Natural Gas Progressivity Tax (Sliding?) (GPT)
CAPEX & OPEX & TT&T Apportioned Separately to Gas & C5+ PTV Streams
BPT+GPT+OPT Ceilings & Floors Applied Separately to Gas & C5+
BPT+OPT+GPT Floors up to 7% of PPV
BPT+OPT+GPT Ceiling (?%)
PT Limits & Offsets
Distinctive Credits & Other Fiscal Incentives Focused separately on Oil (C5+) & Natural Gas
Fiscal Elements Considered for Modification Identified in Italics
Actual Production Tax (PT) Paid
State of Alaska
Pre-CIT Cash Flow
PTV Less PT
Part 1 of 2 (Continues down to CIT and FIT)
David Wood & Associates

Alternative Drivers of Gas Progressivity Tax Evaluated by Fiscal Model

Ten different mechanisms are evaluated. No.1 represents the status quo evaluating gas progressivity as a combined revenue stream with oil (boe) were reviewed in December 2008 report to legislature.

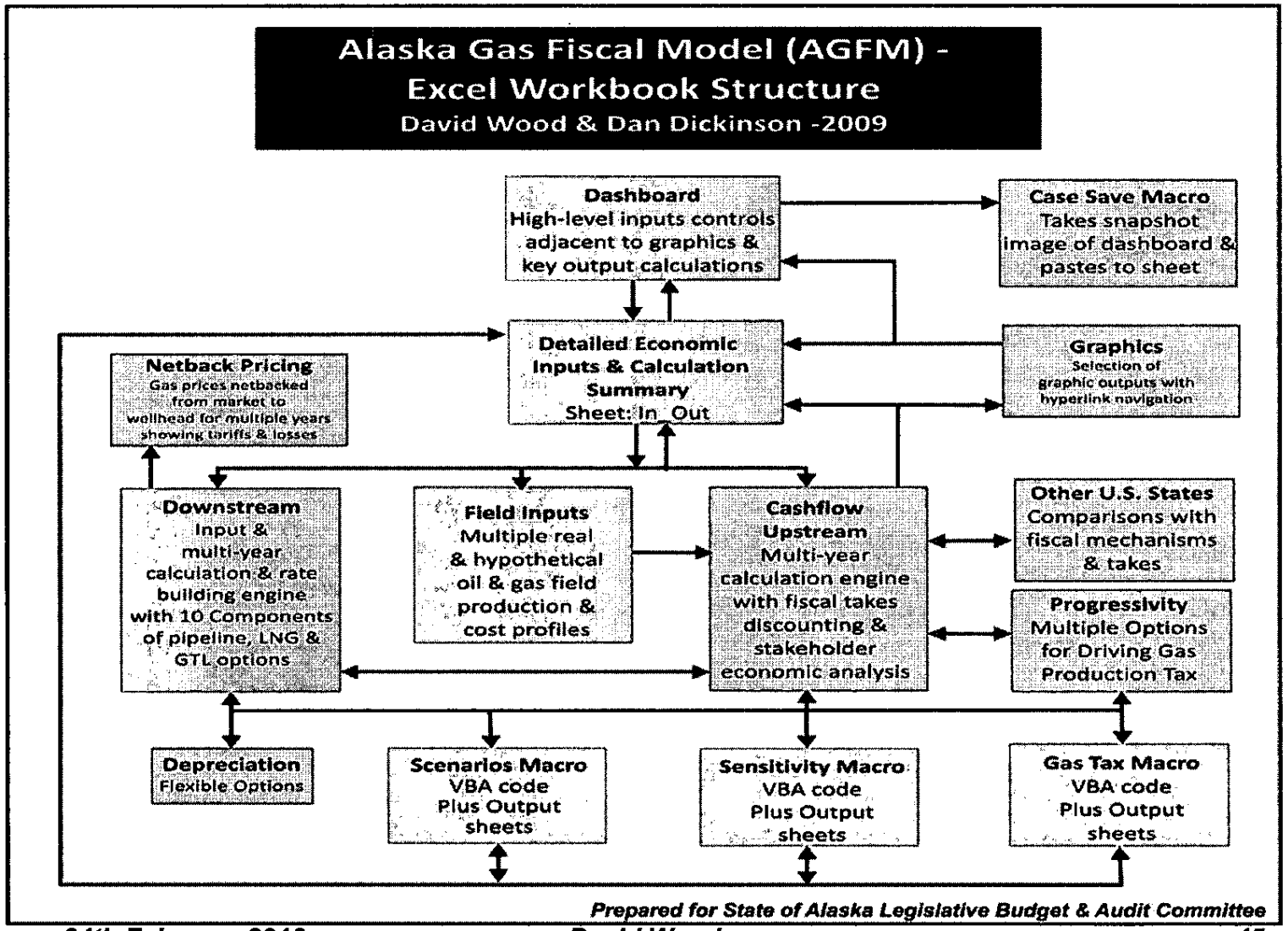
1. CPT: 2008 Rules (combined PTV/boe)
2. GPT / OPT: separates gas and oil on PTV/boe scale ← The easiest first step
3. GPT /OPT: progressivity applied to only 33% of gas PTV
4. GPT: Gas PTV (based on Gas PTV / mmbtu)
5. GPT: R-Factor (cumulative PPV less royalty/cumulative gas costs)
6. GPT: IRR (Investor's Rate of Return of cumulative PTV)
7. GPT: Cumulative gas reserves produced
8. GPT: Annual gas production volumes
9. GPT: Cumulative gas PTV
10. GPT: Mechanism #9 plus allowances to counter regressive elements

Multi-year and multi-scenario fiscal

Integrated upstream & downstream

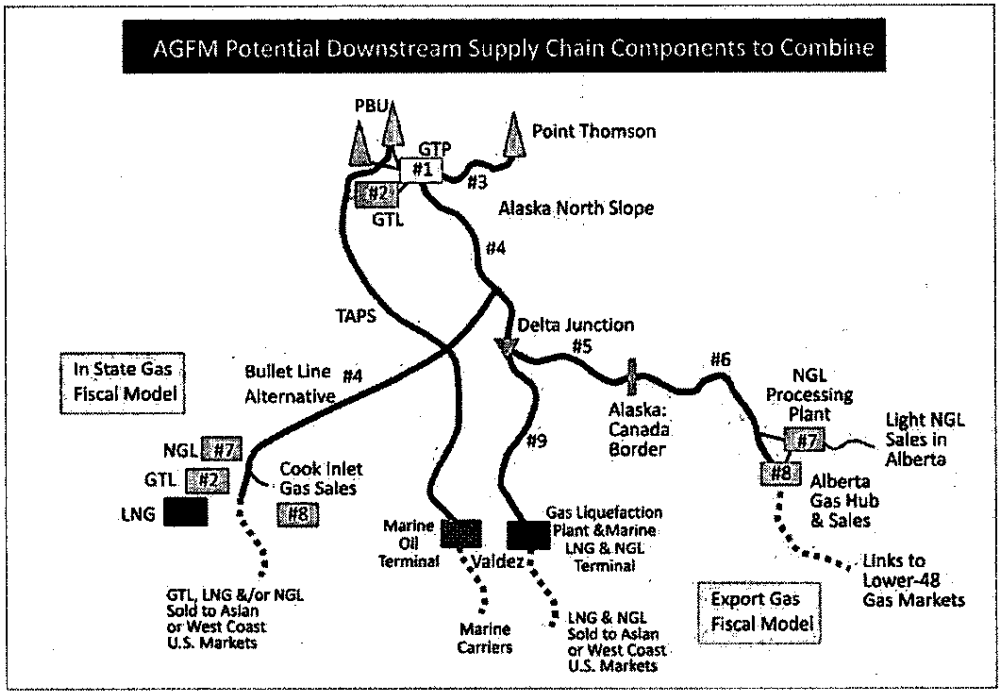
performance cash flow model

AGFM – Alaska Gas Fiscal Model


Alaska Gas Fiscal Model (AGFM) -
Excel Workbook Structure
David Wood & Dan Dickinson -2009
Dashboard
High-level inputs controls adjacent to graphics & key output calculations
Case Save Macro
Takes snapshot image of dashboard & pastes to sheet
Detailed Economic Inputs & Calculation Summary
Sheet: In_Out
Graphics
Selection of graphic outputs with hyperlink navigation
Netback Pricing
Gas prices netbacked from market to wellhead for multiple years showing tariffs & losses
Downstream
Input & multi-year calculation & rate building engine with 10 Components of pipeline, LNG & GTL options
Field Inputs
Multiple real & hypothetical oil & gas field production & cost profiles
Cashflow Upstream
Multi-year calculation engine with fiscal takes discounting & stakeholder economic analysis
Other U.S. States
Comparisons with fiscal mechanisms & takes
Progressivity
Multiple Options for Driving Gas Production Tax
Depreciation
Flexible Options
Scenarios Macro
VBA code
Plus Output sheets
Sensitivity Macro
VBA code
Plus Output sheets
Gas Tax Macro
VBA code
Plus Output sheets
Prepared for State of Alaska Legislative Budget & Audit Committee

AGFM Now Extended to Evaluate In-state Gas Scenarios

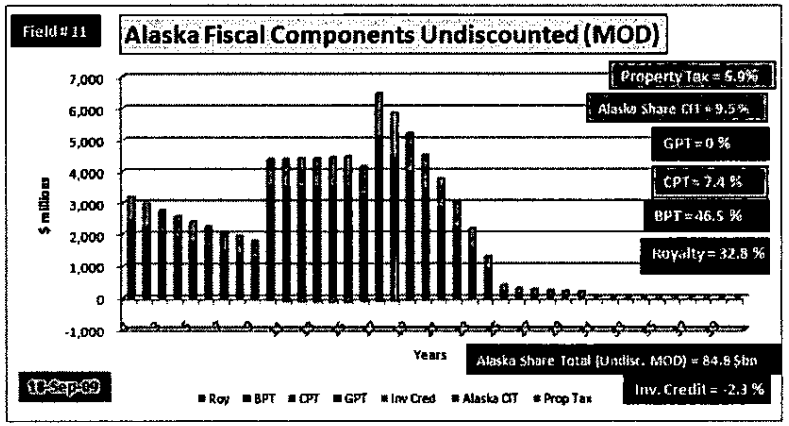
The ten components are selected by entering "1" and de-selected by entering "0" on AGFMs dashboard.

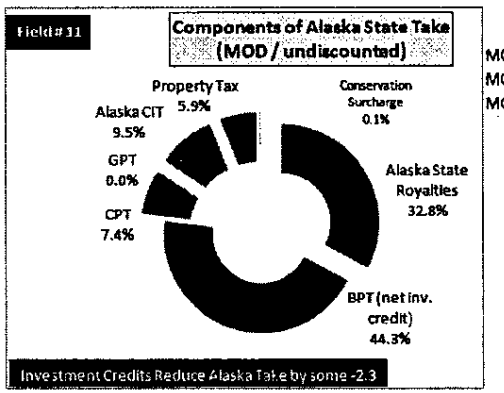


Components "1", "2", "4", "7", "8" and "10" can be reconfigured to model gas export routes or to model In-State "Bullet Line" gas supply to Cook Inlet with optional NGL, GTL and / or LNG plants placed there for exports.

Dashboard Control Sheet:
High-level Controls: Spinners & Graphics

	Save Dashboard Image	Ctrl+y
	The model calculates money of day and real values	
	Key Assumptions	
	Analyse Field # (1 to 20)	11
	Input Option 1=A, 2=B or 3=C (see Fields B6)	1
	1 =A is default for selecting individual fields	
AECO	Gas Destination Price, Year 0 ($/mmbtu)	6.00
	Gas Price Nominal Escalator (%/yr)	2.00%
ANSWC	Oil (C5+) Destination Price, Year 0 ($/barrel)	60.0
	Oil (C5+) Price Nominal Escalator (%/yr)	2.00%
	Cost Nominal Escalator (%/yr)	2.00%
	Buying Power Inflator / Deflator	1.00%
	Capital Costs Sensitivity Adjuster (%)	100.0%
	TT&T Costs Sensitivity Adjuster (%)	100.0%
	Operating Costs Sensitivity Adjuster (%)	100.0%
	Government Nominal Discount Rate (%)	5.00%
	Producer Nominal Discount Rate (%)	10.00%
	Royalty (%)	12.50%
	Base Production Tax (%)	25.00%
	Investment credits (%)	20.00%
	CPT or Separate Mechanism used (0=CPT)	0
	GPT & OPT Mechanisms (0 = CPT rates)	0
	Alternative Progressivity Mechanism (3 to 10)	8
	Entry Tariff to Alberta gas hub $CAD/btu (Year 0):	0.175
	AECO to Henry Hub Differential (US$/mmbtu)	-0.900
	CAD per USD exchange rate	0.862
	Price Premium to Rich Gas (US$/mmbtu)	0.086
	Rich gas has energy content > btu/cf	1100
	Alternative AECO Gas Pricing (1 to 4; 2=base)	2
	ANSWC to WTI Oil Price Differential (US$ / barrel)	-2.000





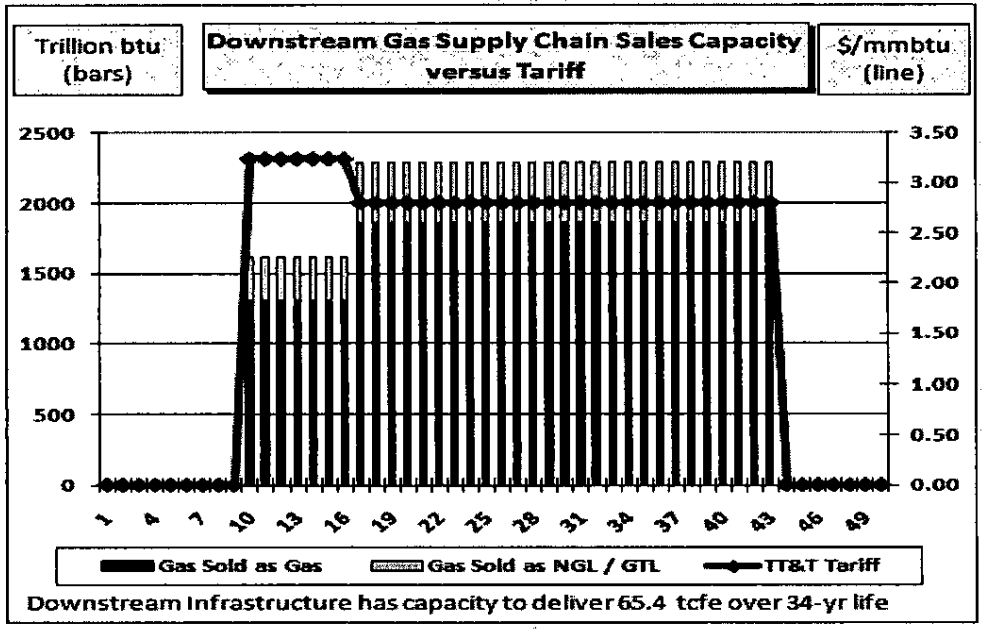
	Gov't Take	Producer
MOD Cashflow:	64.9%	35.1%
MOD NPV @ 5 %:	64.8%	35.2%
MOD NPV @ 10 %:	64.9%	35.1%

Fiscal Elements	$ millions
Royalties	27,822
BPT (net inv. credit)	37,546
CPT	6,299
GPT	0
Alaska CIT	8,070
Property Tax	5,028
Conservation Surcharge	61
AlaskaTotals	84,826
Max Oil/Gas Price Ratio	10.0

Undiscounted and MOD

Dashboard Control Sheet:
Dynamic Graphics & Summary Results

Avg. MOD Revenue / unit gas & NGL ($/millions btu sold)	12.08
Avg. Tariff for T & T / unit gas & NGL ($/millions btu sold)	2.87
Alaska Downstream Property Tax ($/btu sold at capacity)	0.14
Alaska Income Tax Downstream ($/btu sold at capacity)	0.07
Federal Income Tax Downstream($/btu sold at capacity)	0.25

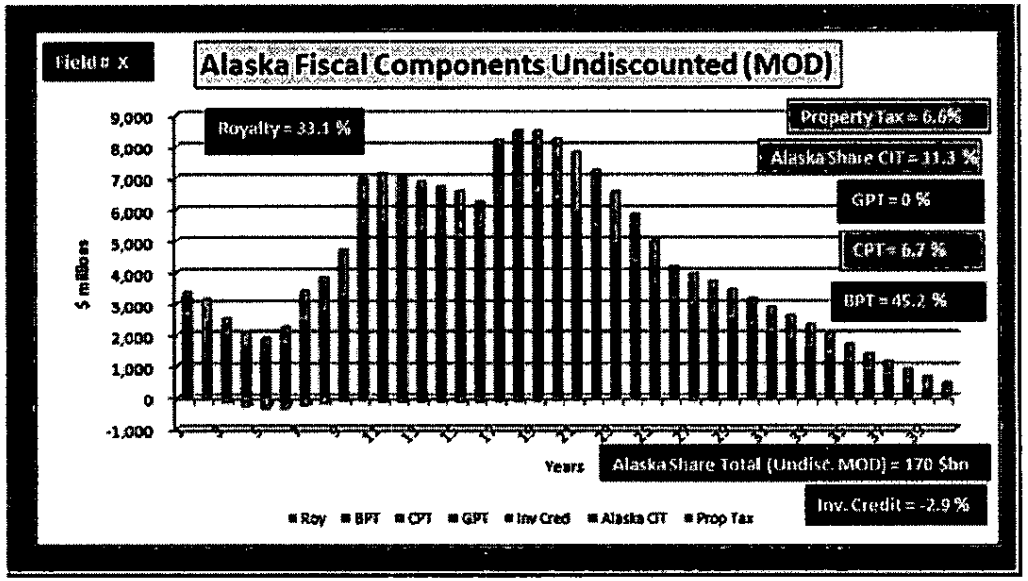


This graphic sits adjacent to the supply chain selection and definition table and responds immediately to changes.

Note the graph shown highlights the start of supply chain, its expansion, gas plus NGL capacities and the multi-year tariff calculated.

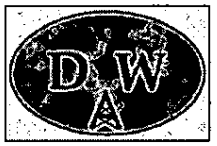
Contributions of Each Fiscal Element to Alaska's Take for Total North Slope (#11 -#14)

The relative contributions to Alaska's fiscal take for price scenario 1 and an ***Pipeline*** supply chain for the ***proved gas reserves*** combination of ***North Slope fields*** shows that gas production would ramp-up in stages, but proven reserves would not fill expanded capacity for more than 3 years.



There are many factors that can be varied in such combination scenarios. For example timing of each field coming on stream and capacity and timing of the gas supply chain infrastructure.

Alaska North Slope Production & Reserves are Dominated by Three Corporations



For fiscal analysis it is important to be able to model the expected fiscal returns from specific corporations. AGFM facilitates this by enabling percentage fractions of individual fields to be combined in a user definition area on sheet Fields.

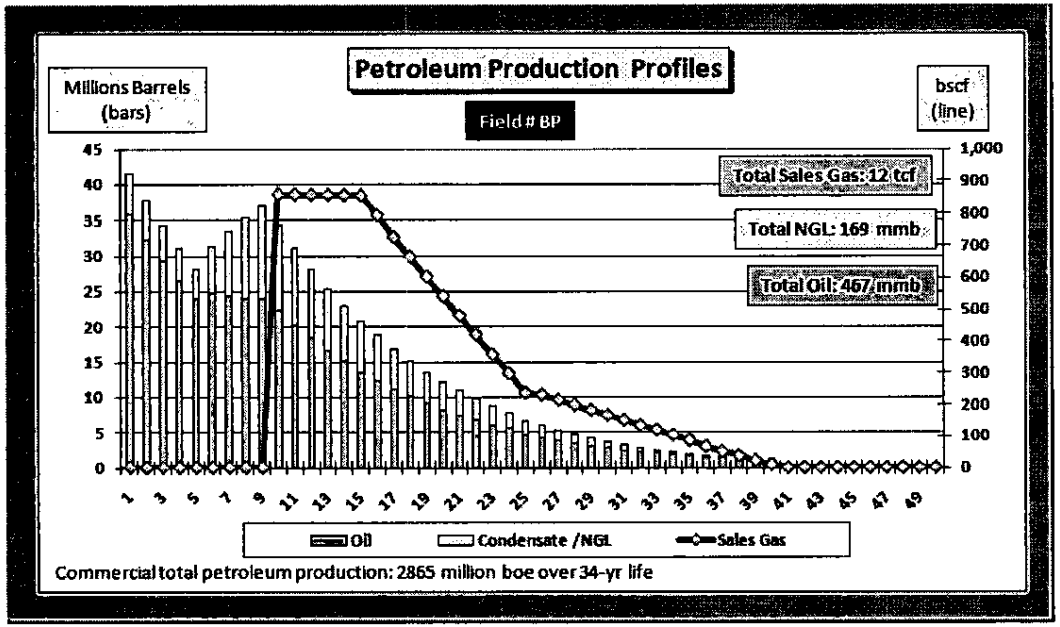
Company Holdings of Major North Slope Fields				
1	2	3	Field	
36.40%	26.36%	36.08%	Prudhoe Bay	Field#11
52.88%	29.19%	2.82%	Point Thomson	Field#12
0.98%	39.03%	55.04%	Kuparuk	Field#13
Exxon Mobil	BP	ConocoPhillips		

Three North Slope fields contain most of North Slope proved gas reserves.

By applying the corporate working interests to those fields a profile for each company can be approximated.

Alaska North Slope Production Profiles Forecast by AGFM for BP

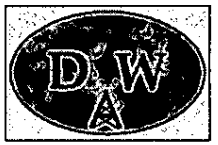
AGFM can be set up to apply corporate interests to the field data to approximate the position of a specific corporation. In this case combining "BP's interests" in Fields #11, #12 and #13 the major North Slope Analogues. [Note input assumptions are based on public domain data. In evaluating appropriate fiscal designs in the absence of data assumptions will be necessary]



These corporate profiles can be analysed in a similar way by AGFM to individual fields.

These forecasts are dependent on the assumptions and input made for the individual fields and supply chains, but are useful for indicative fiscal design evaluations.

Hypothetical Field Cases Evaluated

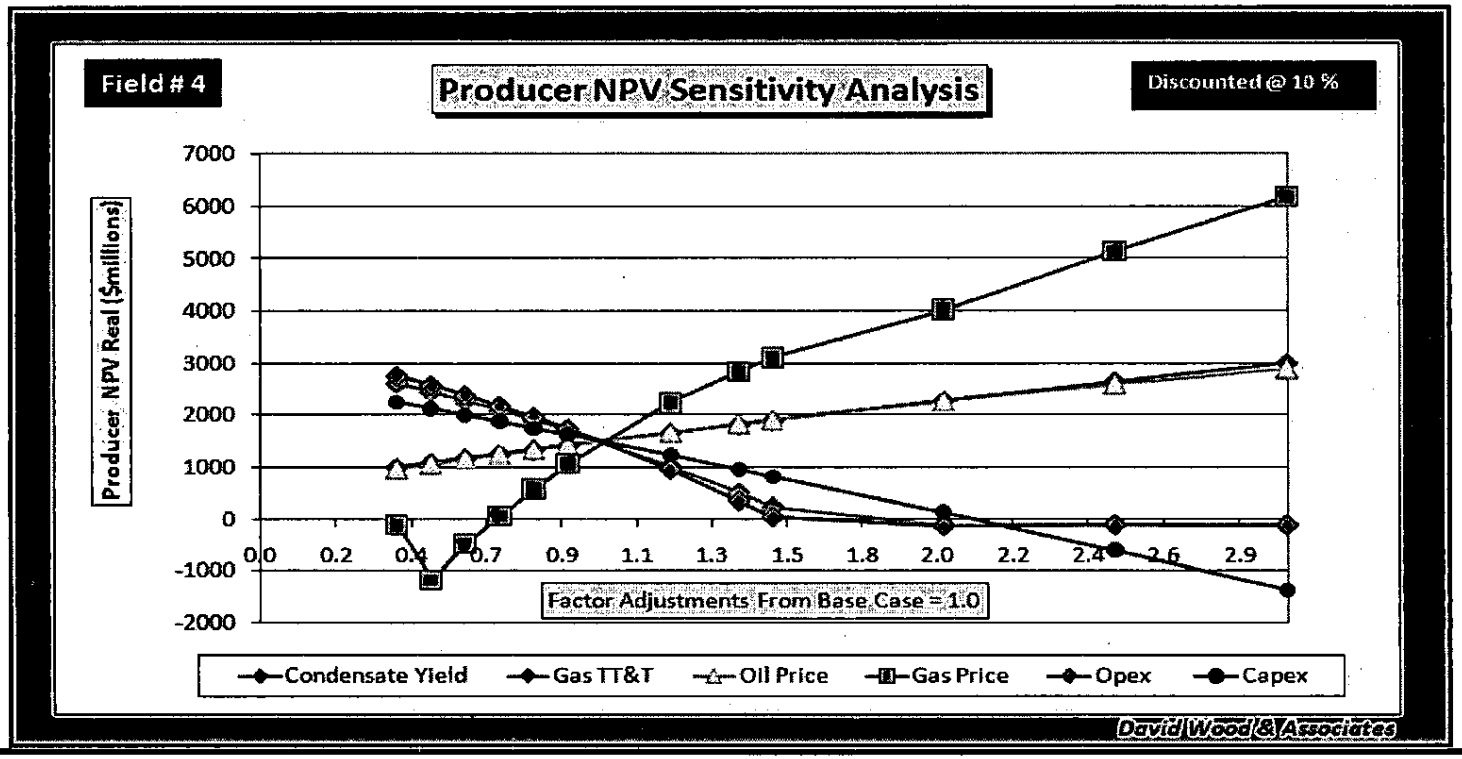


Five non-associated natural gas fields and five oil fields with associated gas were constructed to use with a multi-year fiscal model built in Excel.

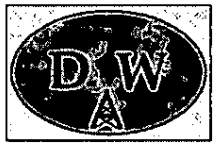
- The natural gas fields (#1 to #5) range in reserve size from 500 bcf to 10tcf.
- The oil fields (#6 to #10) vary in reserve size from 28 mmb (with 20 bcf of associated gas) to 500 mmb (with 690 bcf of associated gas).
- The fields display a wide range of production and cost profiles.
- Base cases for each model field tested with wide ranging sensitivity cases.
- Base case assumptions applied: Year 0 gas price: $7.5 / mmbtu; Year 0 oil price: $80 / barrel; nominal inflation 2% / year. The model allows these and the sensitivities to be changed easily and quickly.

Sensitivity of Alaska Gas Field to Project & Market Variables

Economic performance of a gas field development from a producer's perspective for a large gas field under the prevailing Alaska fiscal system.



Base Case Hypothetical Field Models Reveal High-level Implications for Government Take

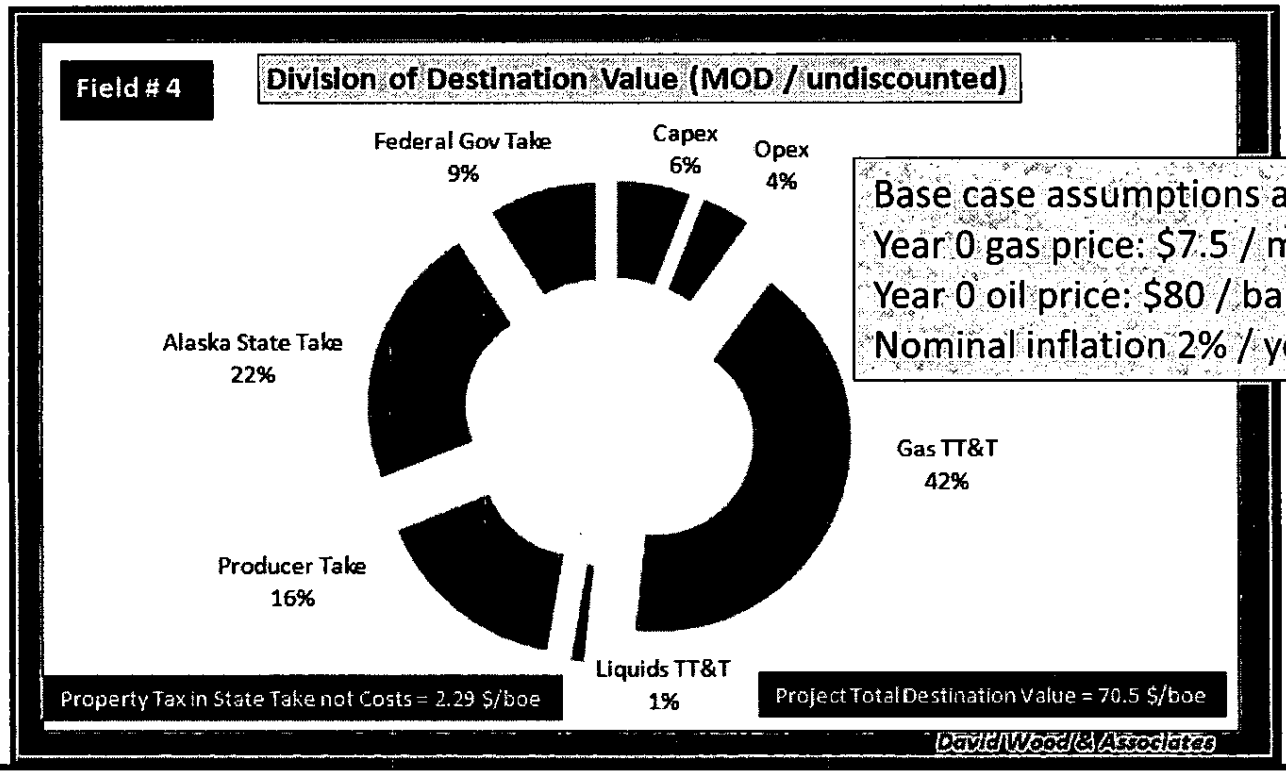


Government take includes Alaska state take and federal government take. The models apply the prevailing Alaska fiscal design and some base case assumptions.

- For stand-alone oil fields (with associated gas):
  - Government take of destination value (gross) is about 60%
  - Government take of destination value less costs (net) is about 75%
- For stand-alone natural gas fields (non-associated gas with NGLs):
  - Government take of destination value (gross) is about 30%
  - Government take of destination value less costs (net) is about 67%
- Exact percentages vary with field sizes, prices and costs.
- Large producers with portfolios of legacy fields under the current system aggregate oil and gas and can see reduced government take.

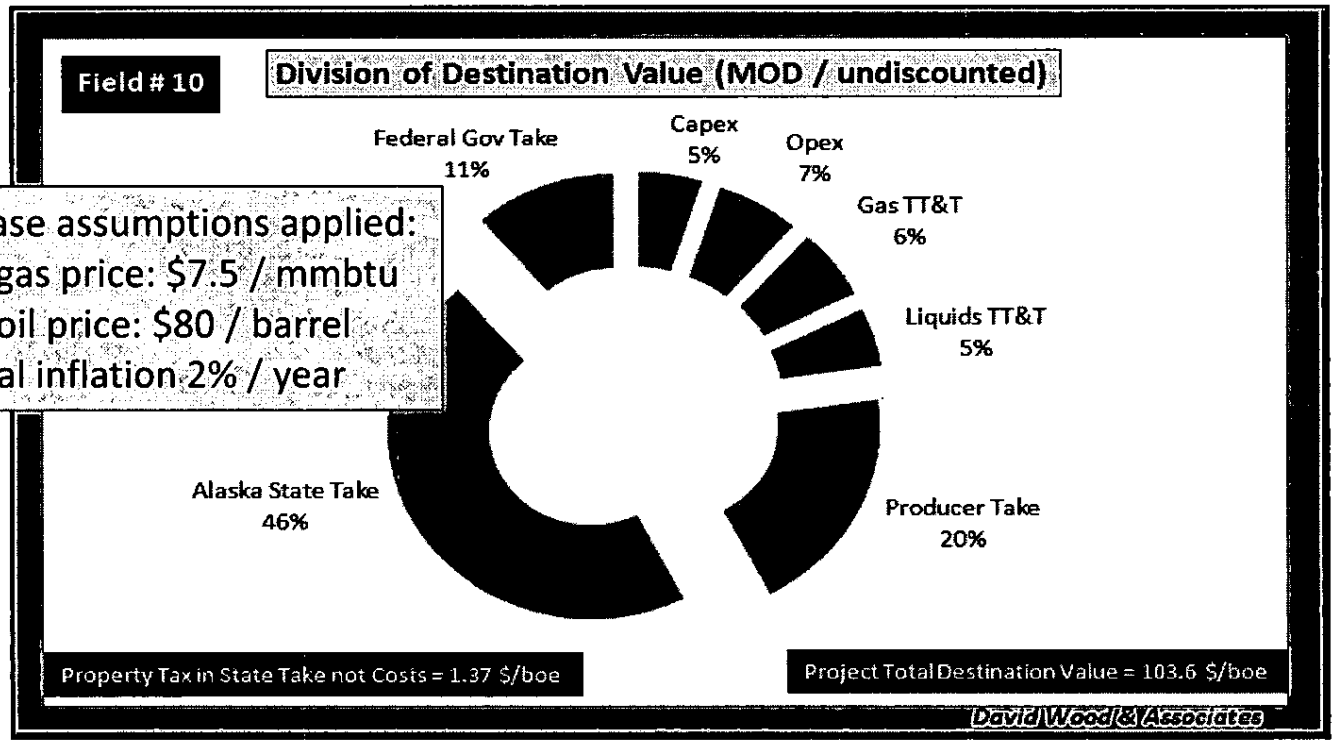
Large Gas Field: Division of Destination Value

For gas fields of various size (5 tcf shown here) gas TT&T takes the largest share of destination value. Alaska takes some 22% of destination value.



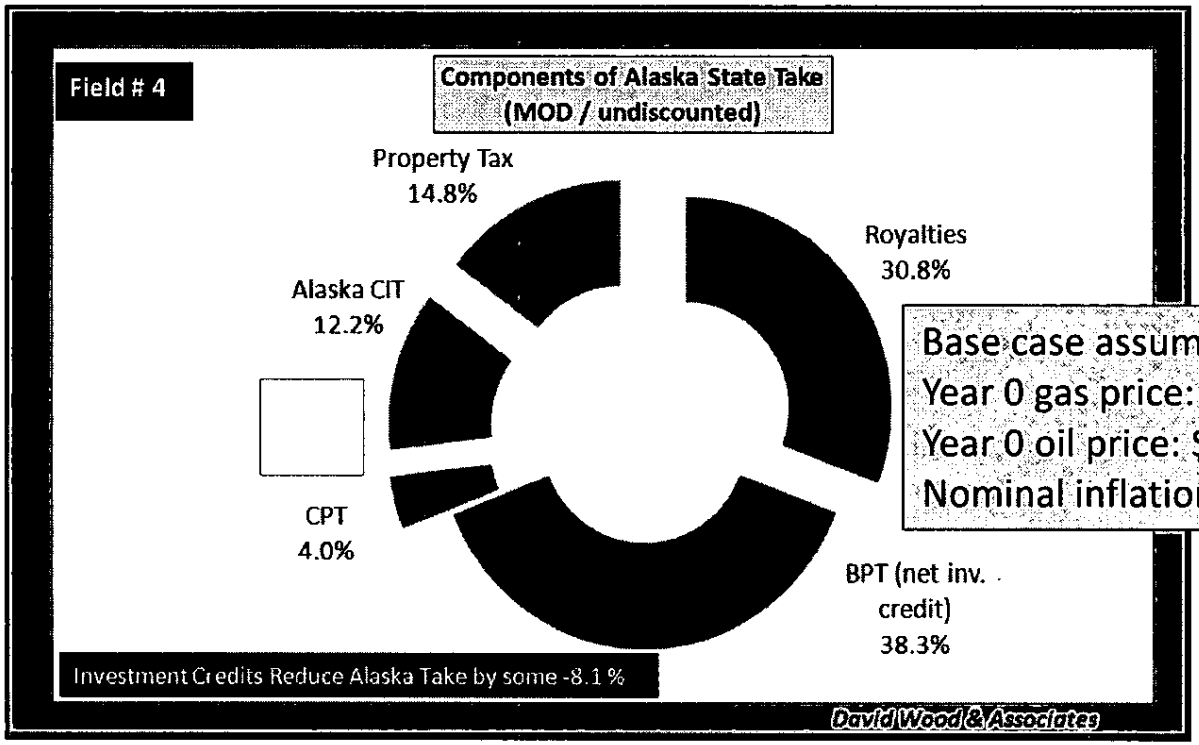
Large Oil Field: Division of Destination Value

For oil fields of various size (500 mmb shown here) costs are less significant than for gas. Alaska takes some 46% of destination value.



Components of Alaska State Take for Large Gas Field

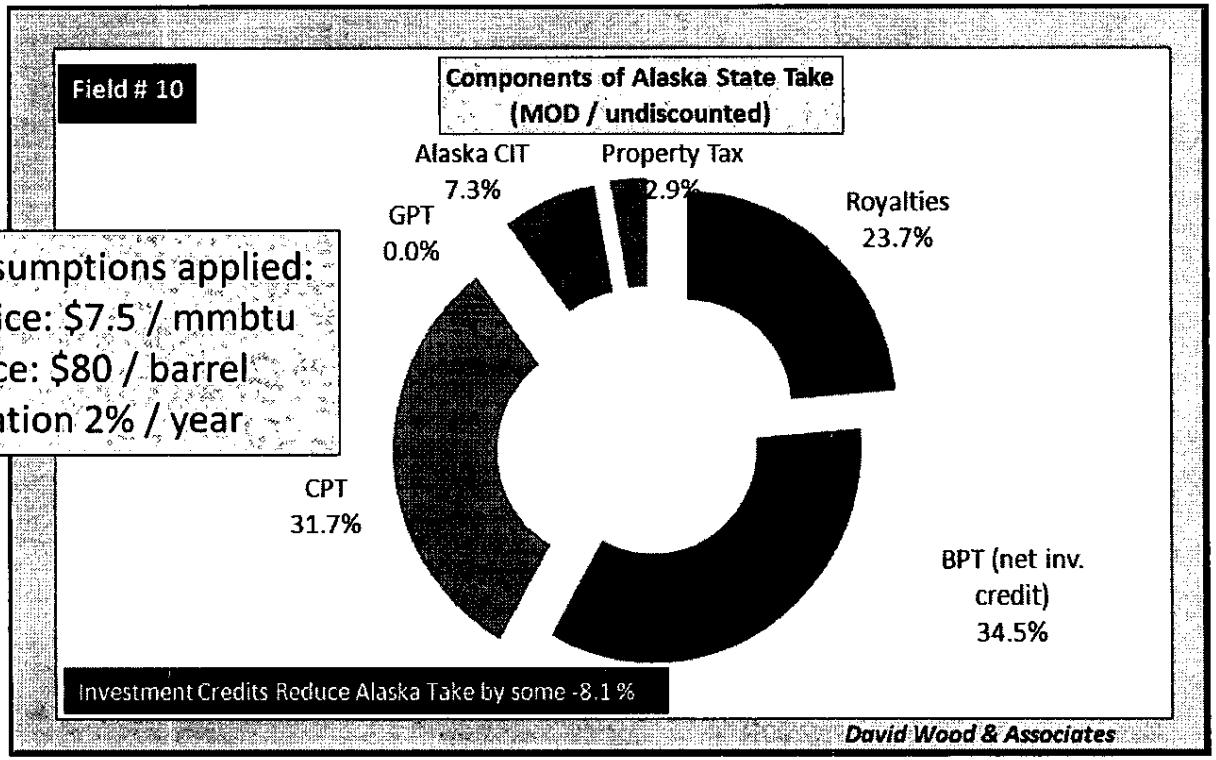
Royalties and basic production tax account for two-thirds of Alaska state take for this 5 tcf field. Base case price and cost assumptions applied.



Base case assumptions applied:
Year 0 gas price: $7.5 / mmbtu
Year 0 oil price: $80 / barrel
Nominal inflation 2% / year

Components of Alaska State Take for Large Oil Field

Basic production tax and combined progressivity tax account for two-thirds of Alaska state take for this 500 mmb oil field.

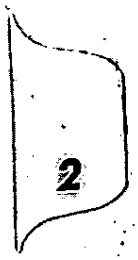


Conclusions & Recommendations

Approaches to Fiscal Design that Can Improve Performance & Credibility

The following are selected recommendations for Alaska from my December 2008 report for the Legislature:

- Develop a clear statement of fiscal strategy and objectives
- Focus on a simple, flexible and progressive fiscal design
- Some level of fiscal stability important to secure investment
- Such designs could be more effective than contractual guarantees
- *Drive progressivity fiscal elements for gas with gas PTV (not boe)*
- Consider return on investment drivers for progressivity taxes
- Combine progressivity tax with allowances to offset regressive elements
- Aim to clarify and optimize fiscal revenue streams from NGLs
- Consider state equity involvement in strategic infrastructure projects
- Promote cost disclosure and control with some fiscal incentives
- Apply time constraints to new leases to develop resources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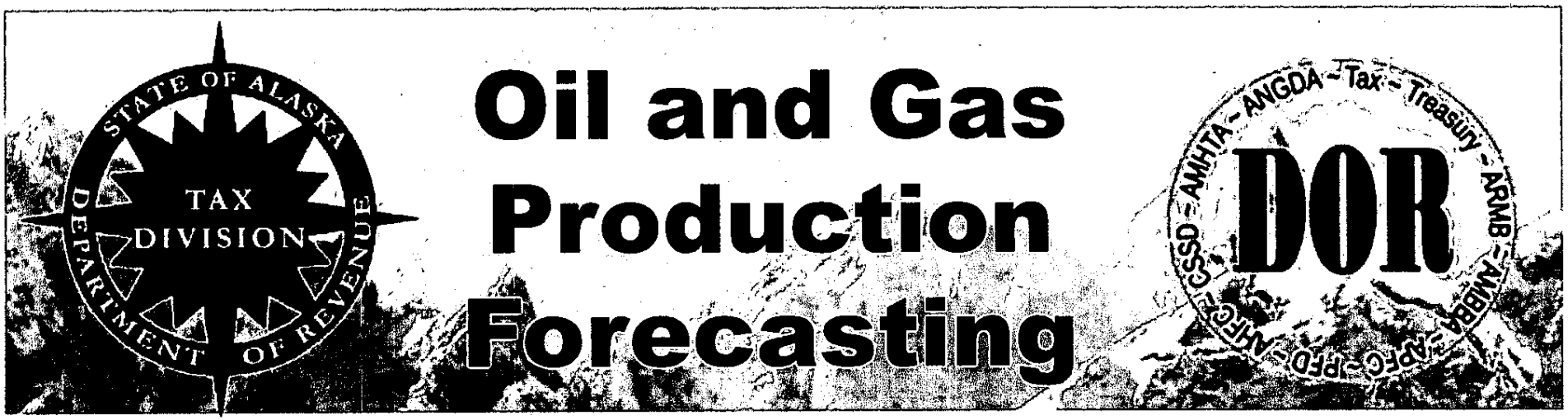
2010 Oil & Gas Production Tax Review

Index



Presentation to the Senate Finance Committee February 16, 2010 Alaska Department of Revenue

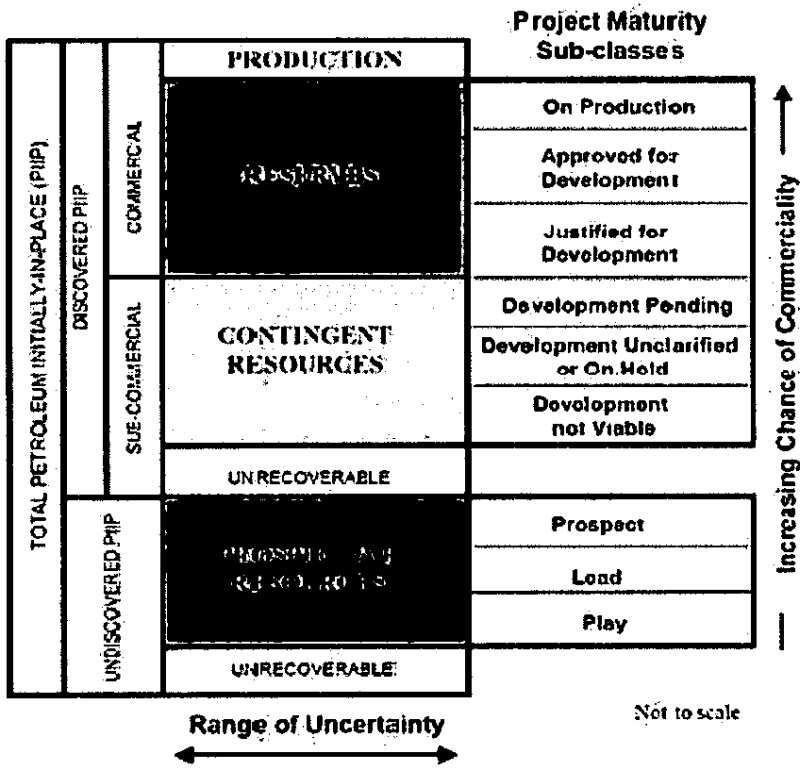
Jennifer Duval
Petroleum Economist

Frank Molli, P.E.
President, Molli Computer Services Inc.

Outline for Presentation

- **What do we forecast and why?**
- **Factors that affect forecast**
- **Review of Alaska North Slope production profiles**
- **Fall 2009 forecast methodology**
  - **Decline Curve Analysis**
  - **Demonstration**

What Do We Forecast? Reserves vs. Resources



http://www.spe.org/spe-site/spe/spe/industry/reserves/

Three Categories of Forecasted Production

1) Currently Producing- Includes base production and enhanced recovery production from investment in rate enhancing activities (perforations, stimulations, well workovers, gas and water injection support).
2) Currently under Development- New projects that are currently funded or awaiting project sanction in near future.

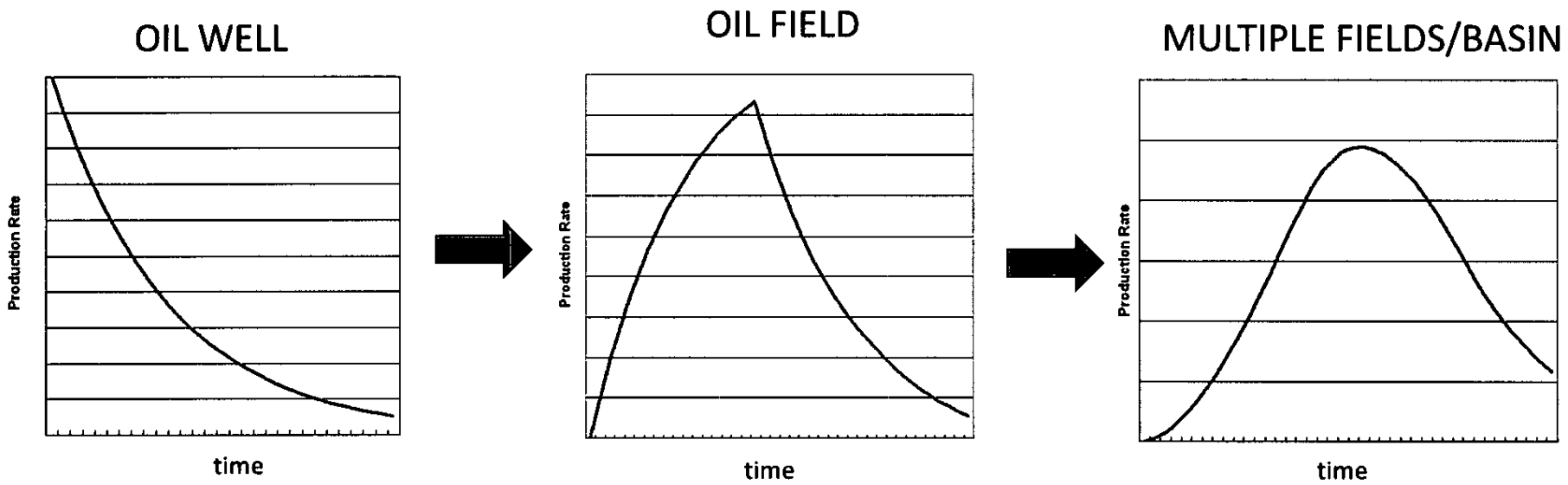
Three Categories of Forecasted Production

3) <u>Currently Under Evaluation</u>- Includes technically viable projects in the "pencil sharpening" stage where engineering, cost, risk and reward are being actively evaluated. Unfunded but are considered to have a high chance of being brought to fruition.

Factors That Affect Production Forecasting

1. **GEOLOGY**
   - Rock type and formation characteristics
   - Depth, thickness, pressure
   - Oil & gas characteristics (oil gravity, viscosity, water content, etc.)
2. **DEVELOPMENT PLAN**
   - Well density and development rate
   - Well bore size and completion technique
   - Artificial lift and enhanced oil recovery
   - Facilities & surface operations
3. **COMMERCIAL**
   - Project economics
   - Oil price and market conditions
   - Government Policy: access, regulation, taxation
4. **PRODUCTION PROFILE**
   - History, stage of depletion
   - Use production profile to extrapolate trends
5. **TIMING!**

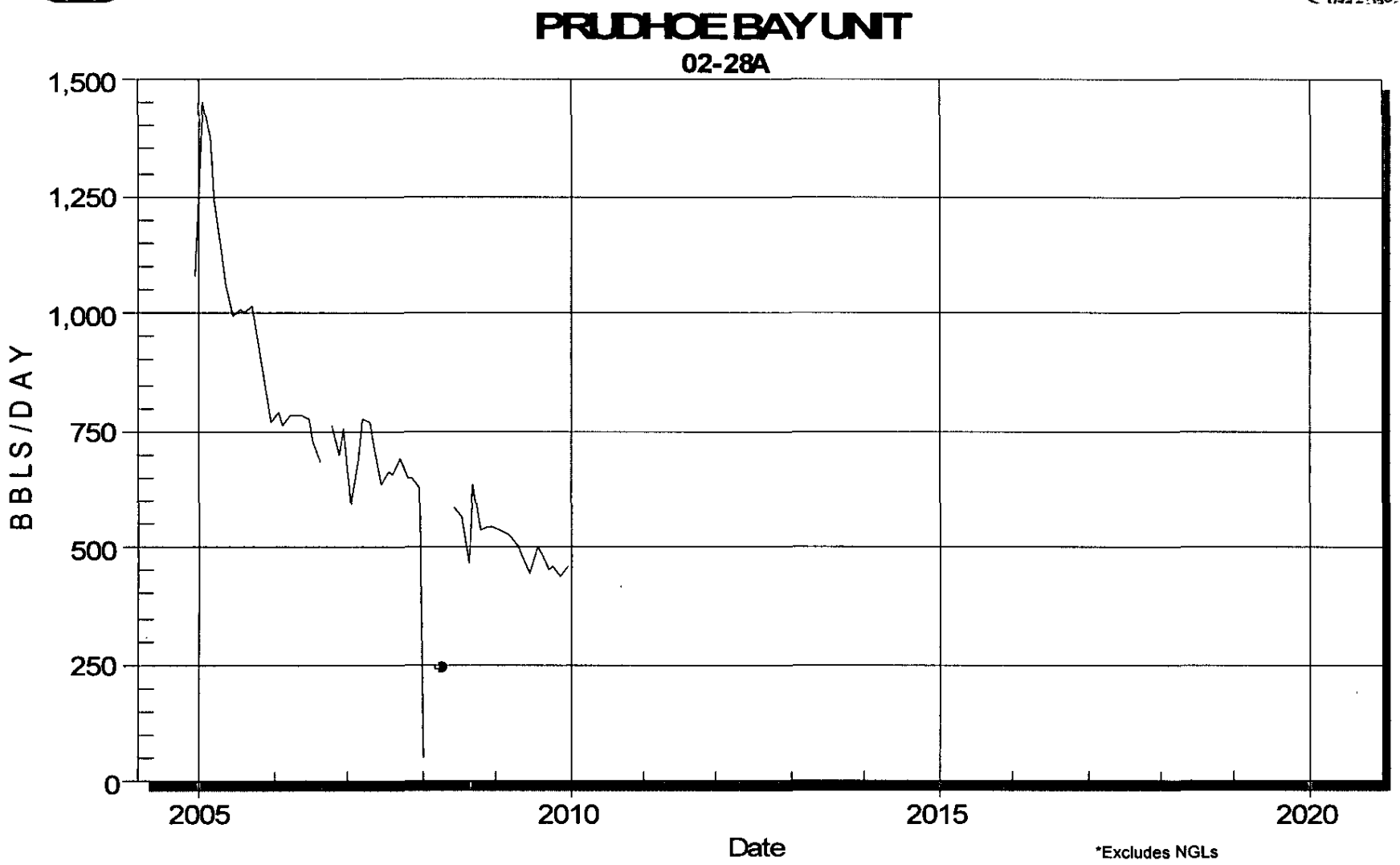
Typical Production Profile



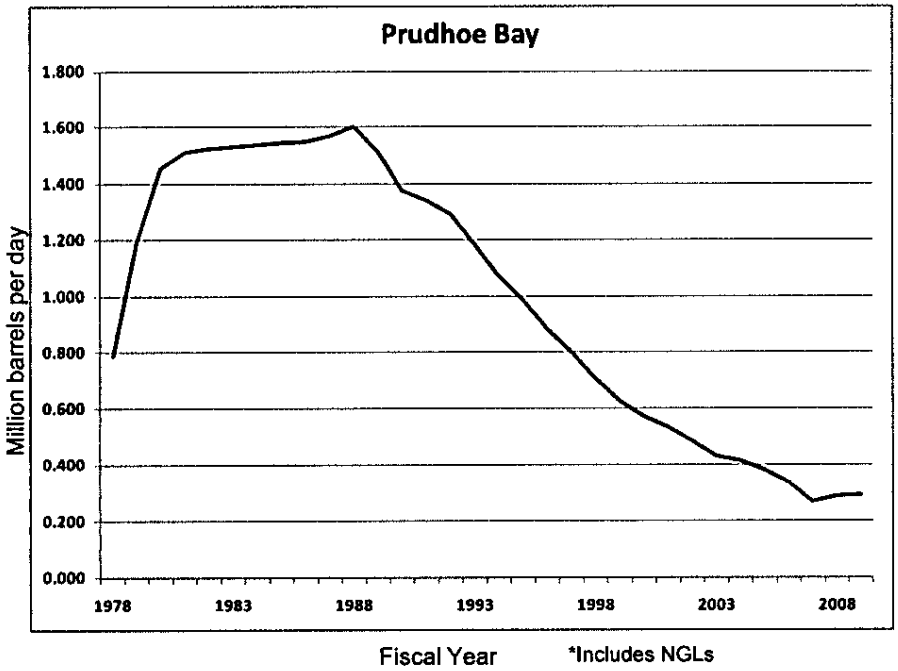
Production increases at first, reaches a peak, then declines. The decline rate typically levels off in later years.

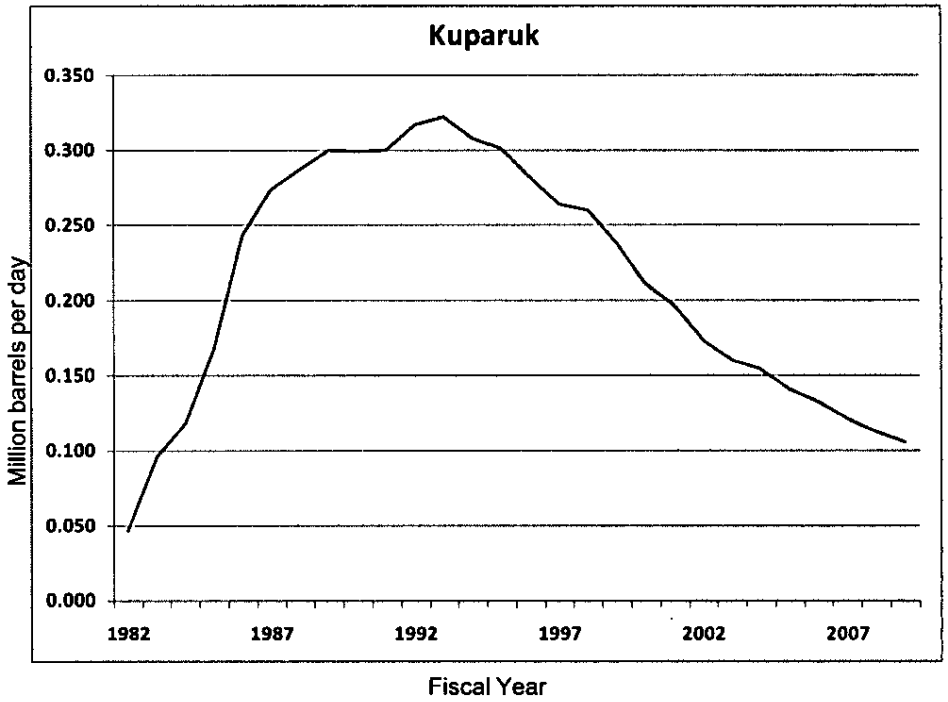
The field's geology, operator's development plan, and commercial factors, all influence the shape of the curve.

Production Profile of a Prudhoe Well

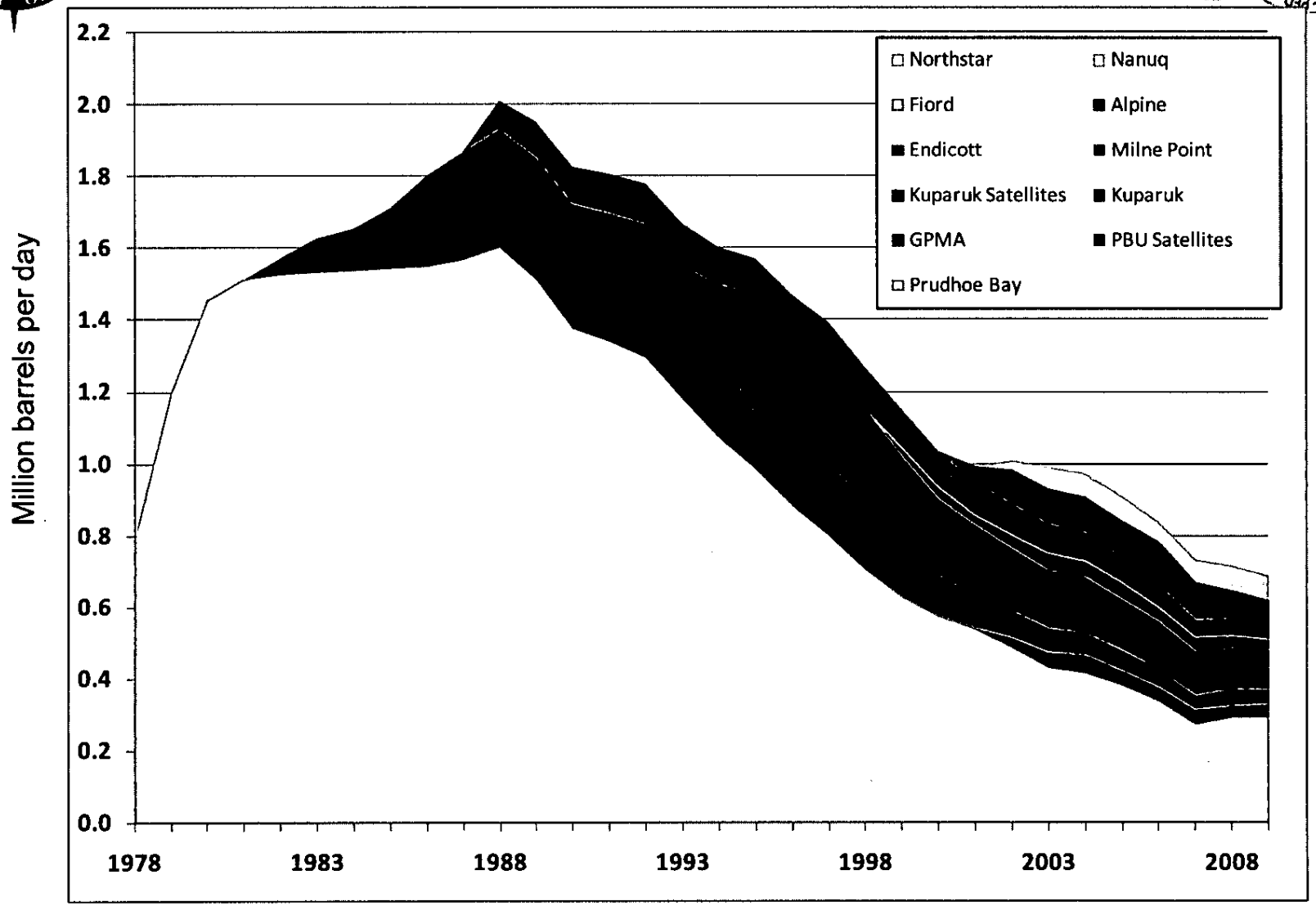


Production Profile at Field Level: Prudhoe & Kuparuk





Alaska North Slope History



*Includes NGLs

North Slope Production Decline

FY 1988: production peak → 2.01 million barrels per day (bpd).

FY 2009: production → 693,000 bpd, a 66% decline since peak.

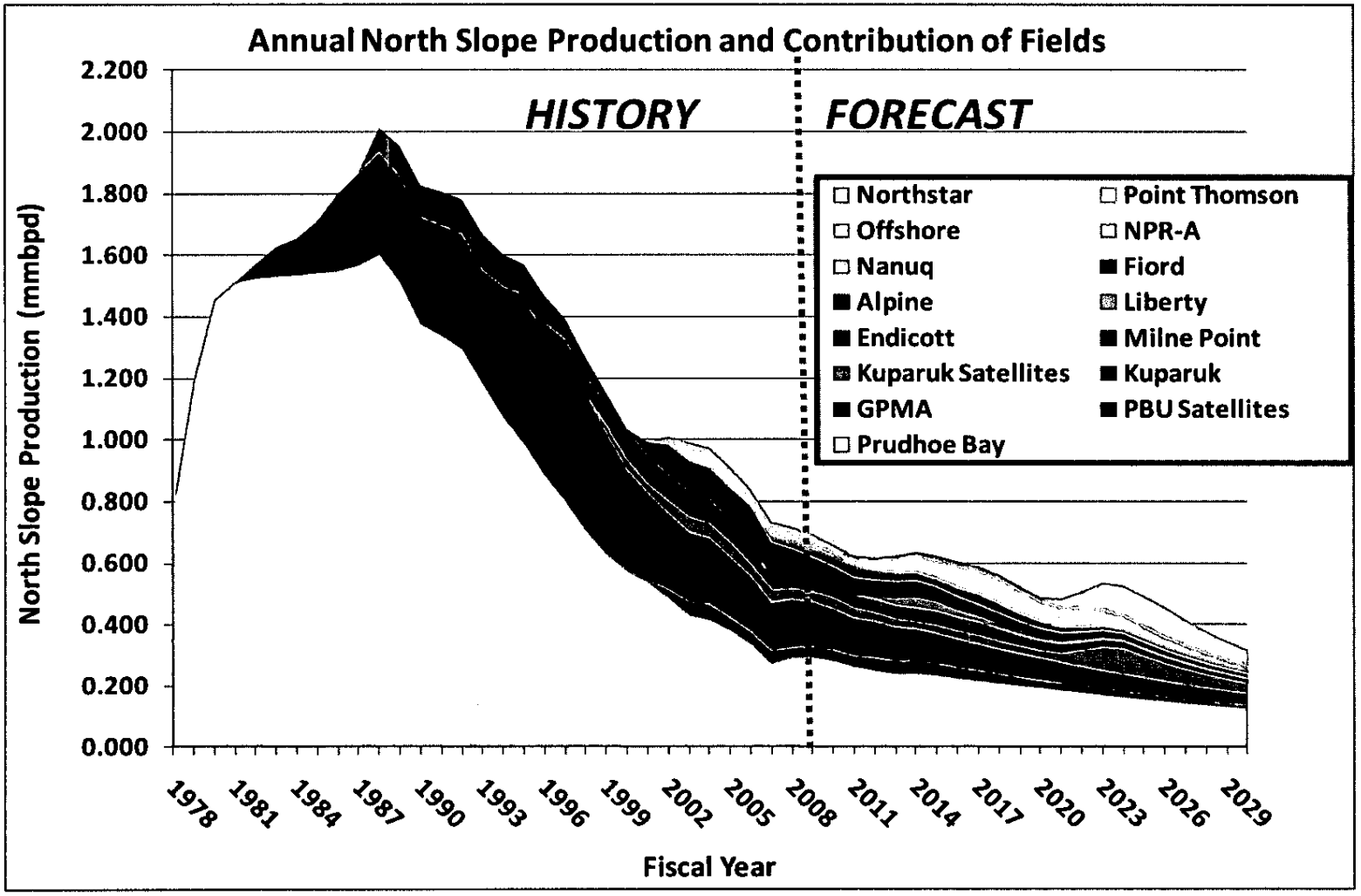
FY 1988 to date: production decline rate → 4.9% per year, on average.

Over the last 10 years, production decline rate = 4.8% per year, on average.

***Excluding 2007, 4.0% decline on average**

We expect the decline rate to flatten out to 3.6% per year, on average, through FY 2030.

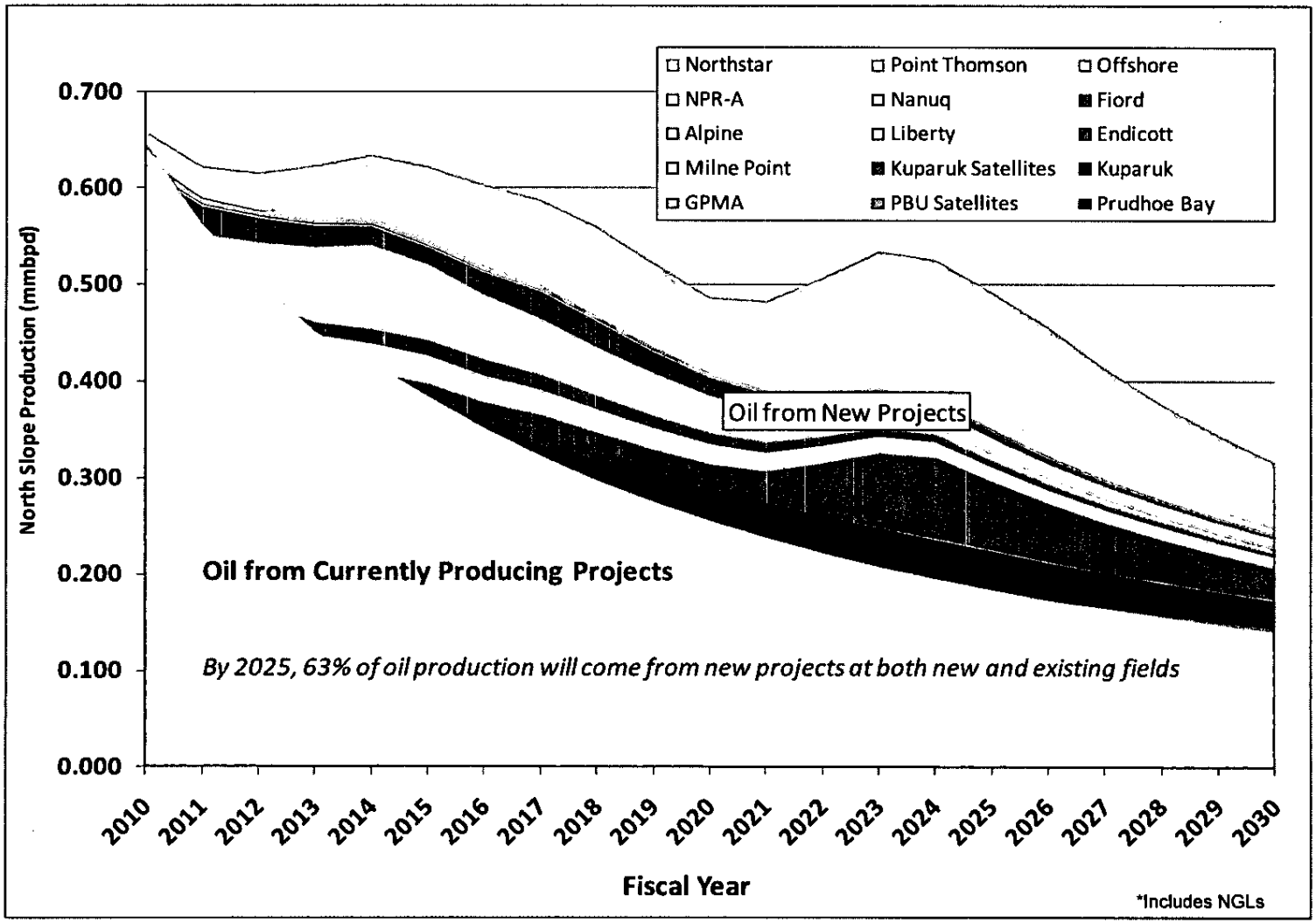
ANS Production History & Forecast



*Includes NGLs

Source: Fall 2009 Revenue Sources Book

Forecasted ANS Production FY 2010 - 2030



Source: Fall 2009 Revenue Sources Book

Timing is Important!

DOR's FY 2010 forecasted total NS production:

Spring 1989- 104,000 bpd

Spring 1994- 583,000 bpd

Fall 2009- 659,000 bpd

Plans of Development and discussions with the operators help us forecast the timing.

***However, operators are not bound to what they provide to us. Budgets can change; partners may not approve projects.**

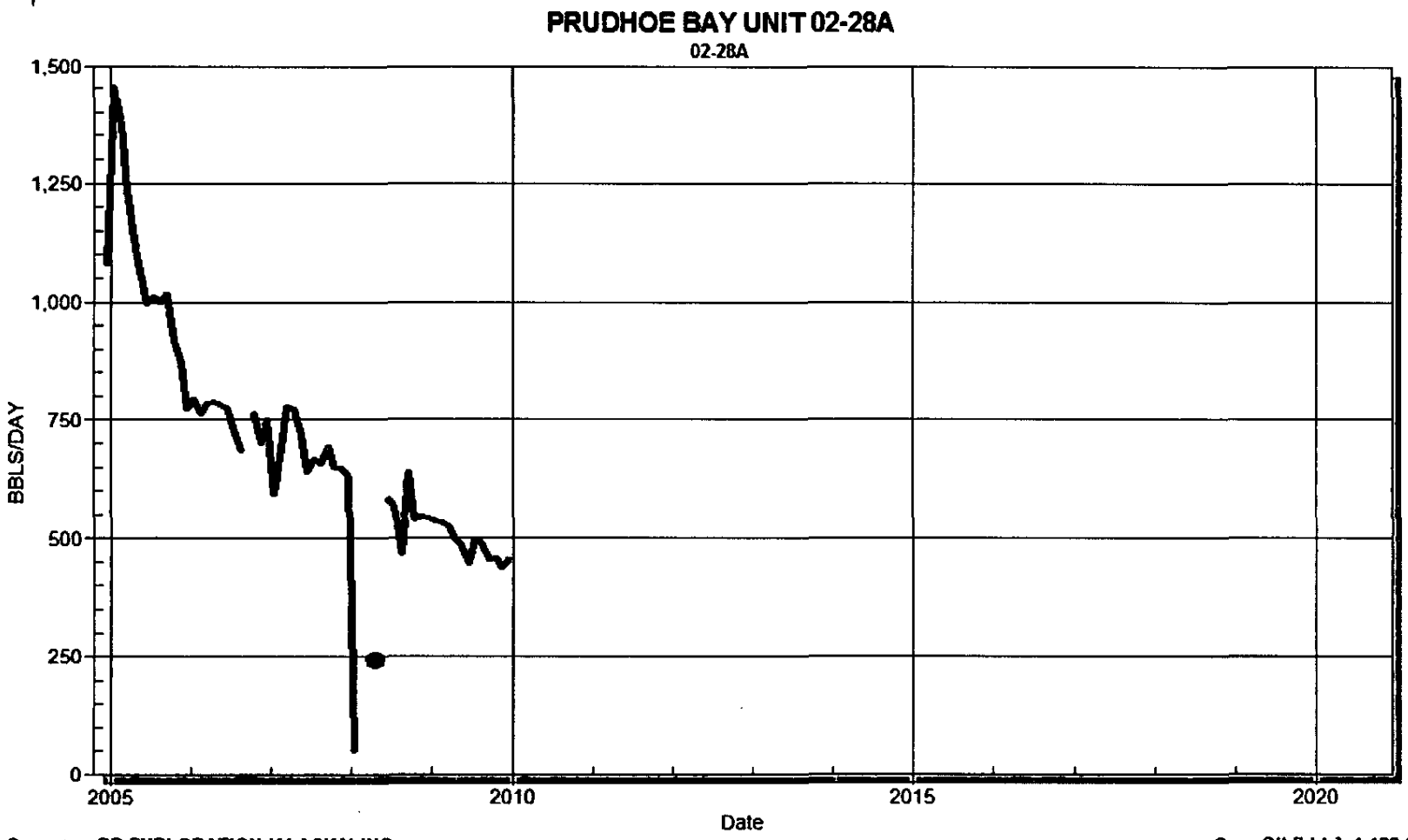
AOGCC

Monthly Production Data For Every Well

Decline Curve

What is a decline curve?

Data Plotted On A Linear Scale

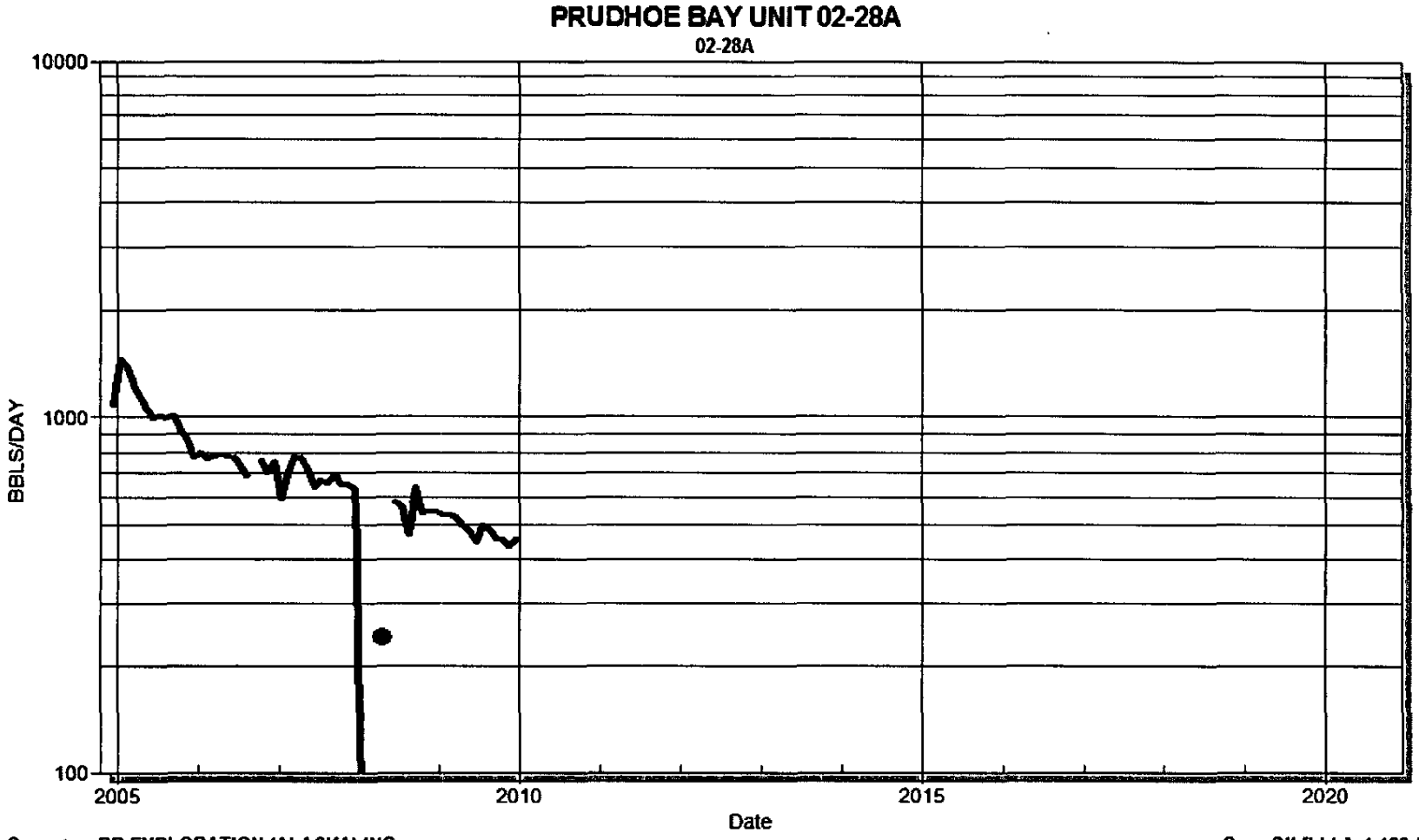


Operator: BP EXPLORATION (ALASKA) INC
Field: 640150 PRUDHOE BAY
Reservoir: PRUDHOE OIL

Cum Oil [bbls]: 1,122,583
Cum Gas [mcf]: 15,544,283
Cum Water [bbls]: 18,780
*Excludes NGLs

1667

Data Plotted on a Log Scale



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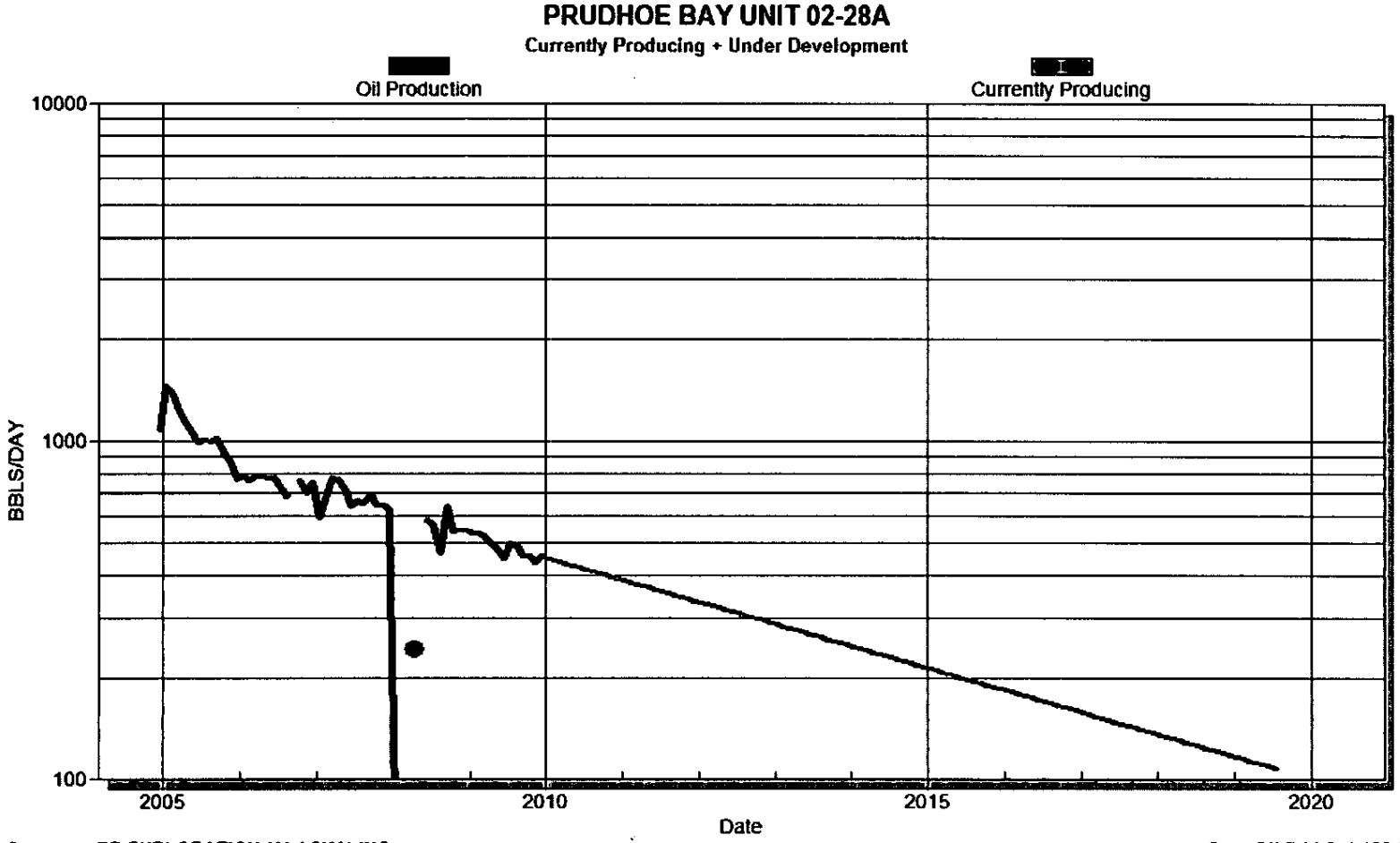
Cum Gas [mcf]: 15,544,283
Cum Water [bbls]: 18,780

*Excludes NGLs

2/25/2010

Decline Curve Extrapolates Trend



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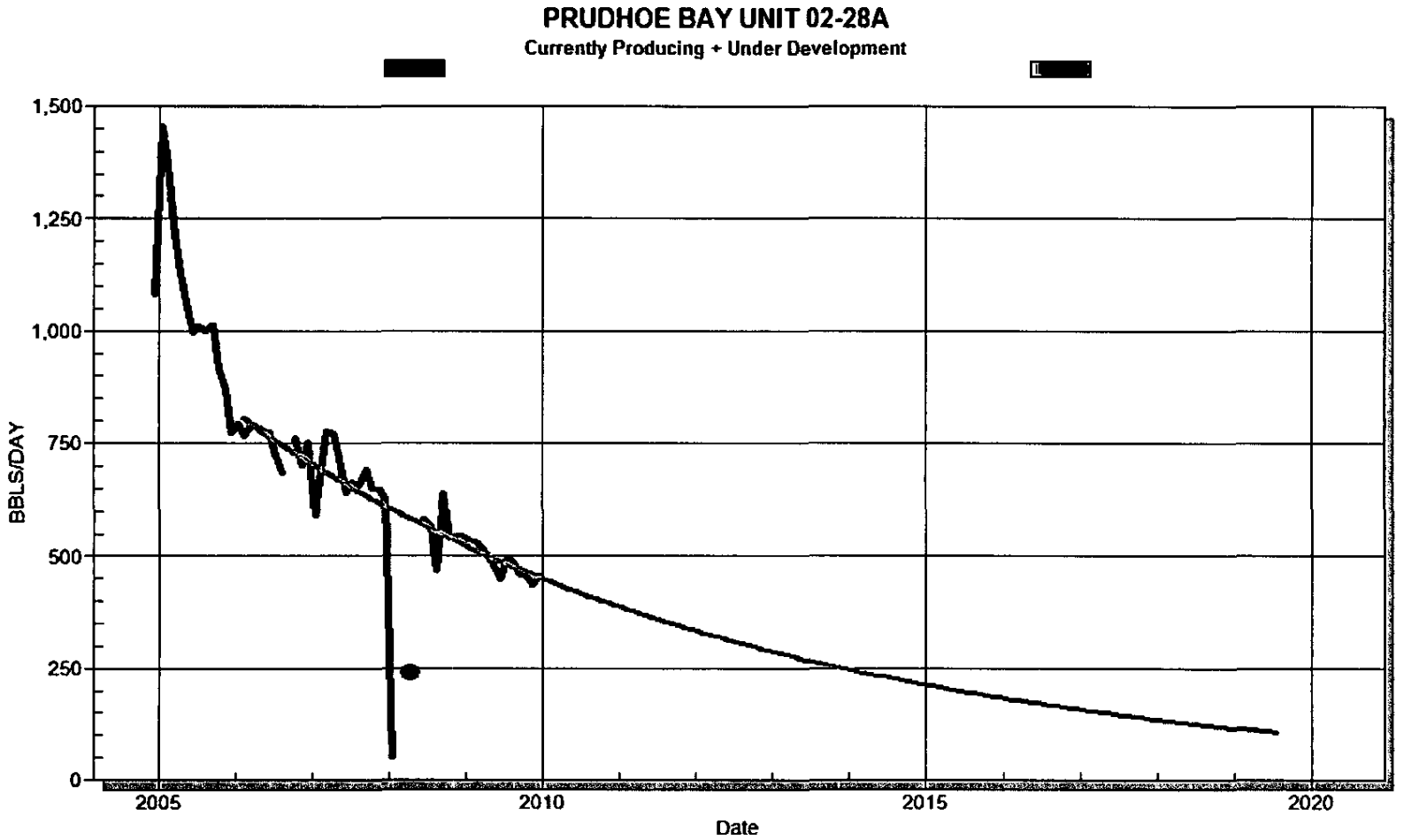
*Excludes NGLs

Trend (linear scale)



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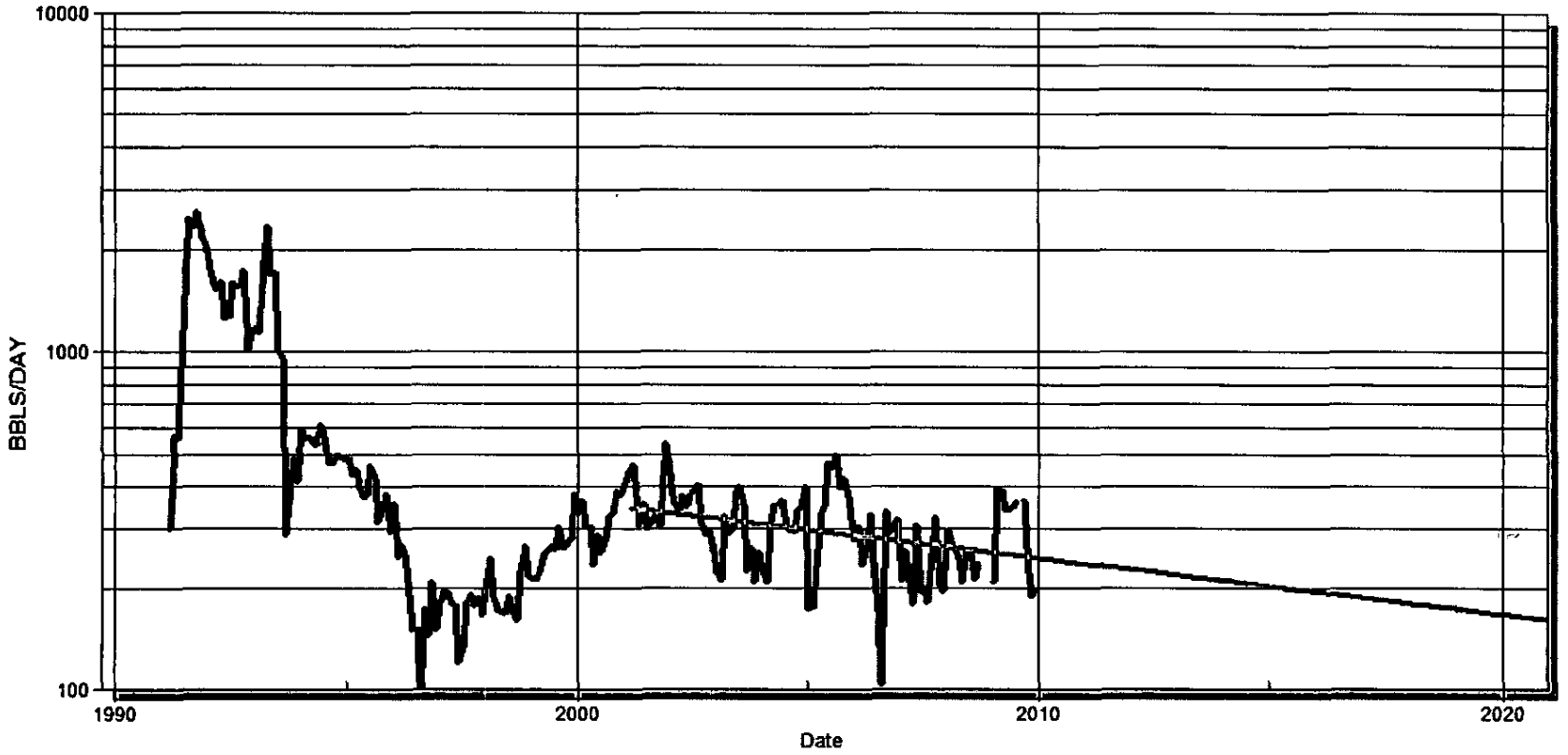
Cum Gas [mcf]: 15,544,283
Cum Water [bbls]: 18,780

*Excludes NGLs

Another Prudhoe Bay Decline Curve

PRUDHOE BAY UNIT P-16

Currently Producing + Under Development

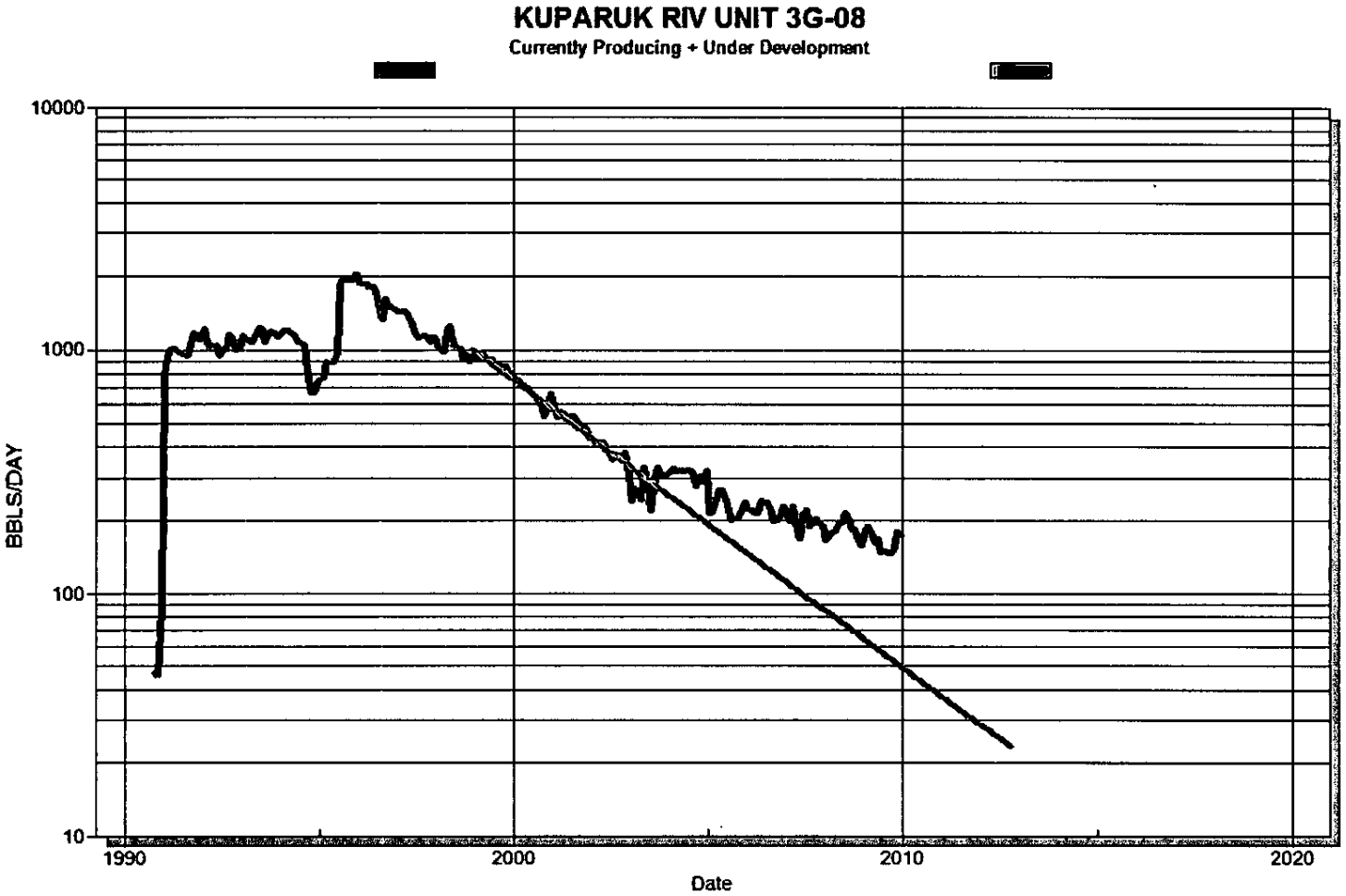


Operator: BP EXPLORATION (ALASKA) INC
Field: 640150 PRUDHOE BAY
Reservoir: PRUDHOE OIL

Cum Oil [bbls]: 2,998,630
Cum Gas [mcf]: 4,851,252
Cum Water [bbls]: 6,517,122

*Excludes NGLs

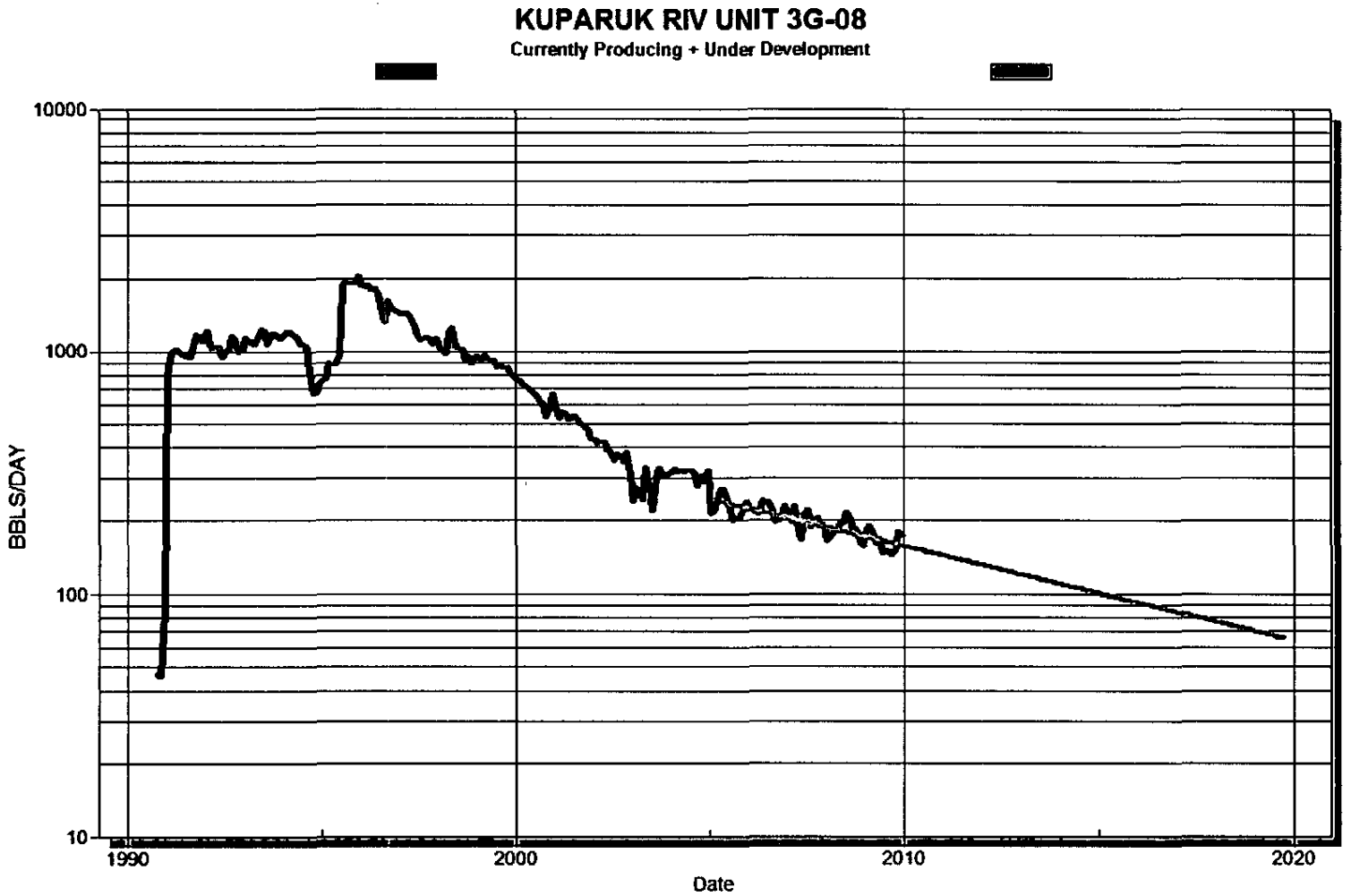
KRU Well Decline Curve At The End Of 2002...



Operator: CONOCOPHILLIPS ALASKA INC
Field: 490100 KUPARUK RIVER
Reservoir: KUPARUK RIV OIL

Cum Oil [bbls]: 4,930,933
Cum Gas [mcf]: 3,372,126
Cum Water [bbls]: 1,924,543

Kuparuk River Unit Well Decline Curve



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Field: 490100 KUPARUK RIVER
Reservoir: KUPARUK RIV OIL

Cum Oil [bbls]: 4,930,933
Cum Gas [mcf]: 3,372,126
Cum Water [bbls]: 1,924,543

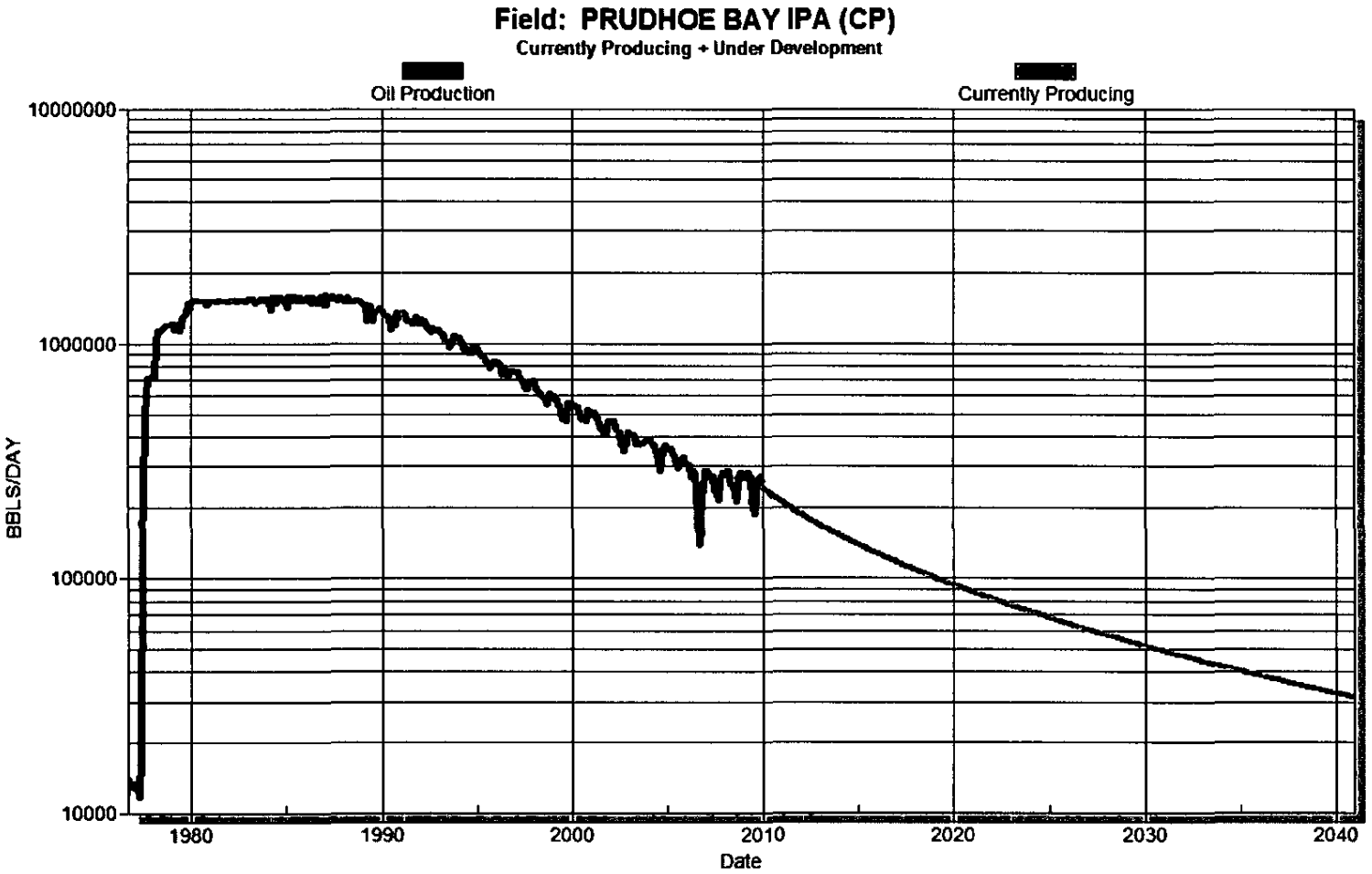
To Generate A Field Forecast:

1. Upload production history from AOGCC into database

2. Apply a decline curve to every well with recent production history data

3. Sum all of the production history and forecasts

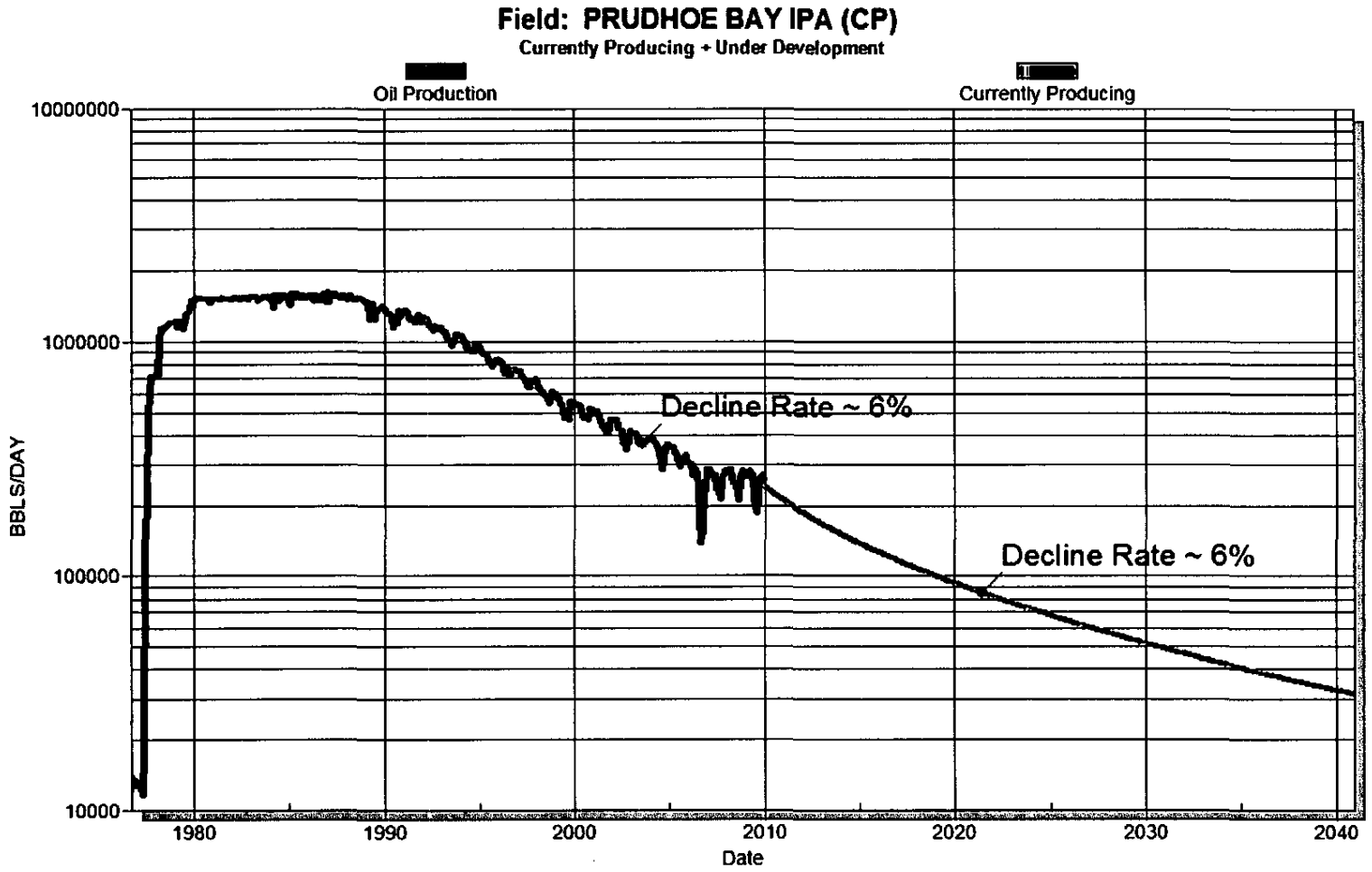
Prudhoe Bay
Currently Producing Wells



Operator: BP EXPLORATION (ALASKA) INC
Field: PRUDHOE BAY (IPA)
Reservoir: PRUDHOE OIL

Cum Oil [bbls]: 11,192,937,517
Cum Gas [mcf]: 61,452,931,005
Cum Water [bbls]: 9,021,006,529
*Excludes NGLs

Prudhoe Bay
Currently Producing Wells



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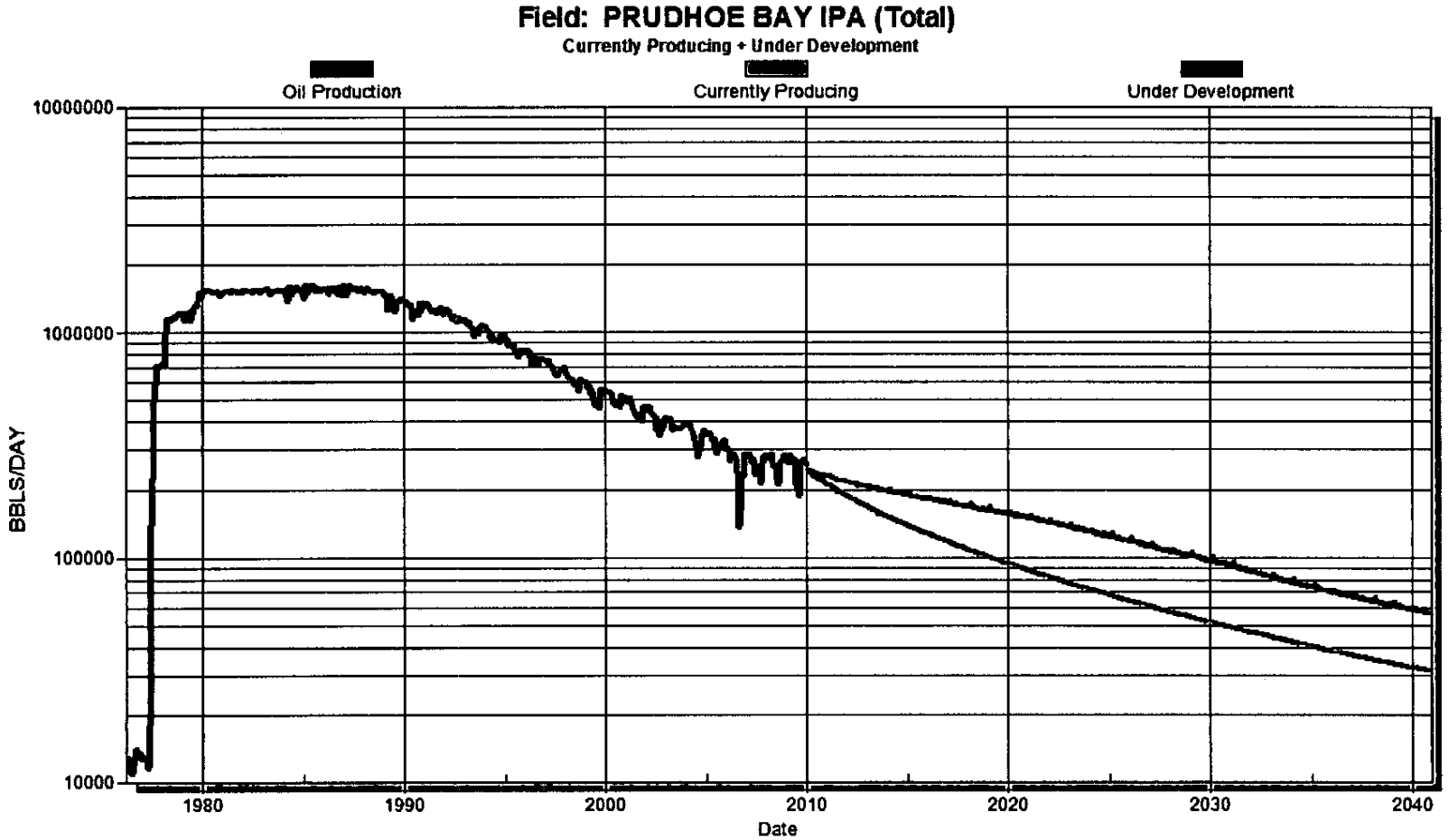
Cum Gas [mcf]: 61,452,931,005
Cum Water [bbls]: 9,021,006,529

*Excludes NGLs

Prudhoe Bay
Currently Producing + Under Dev



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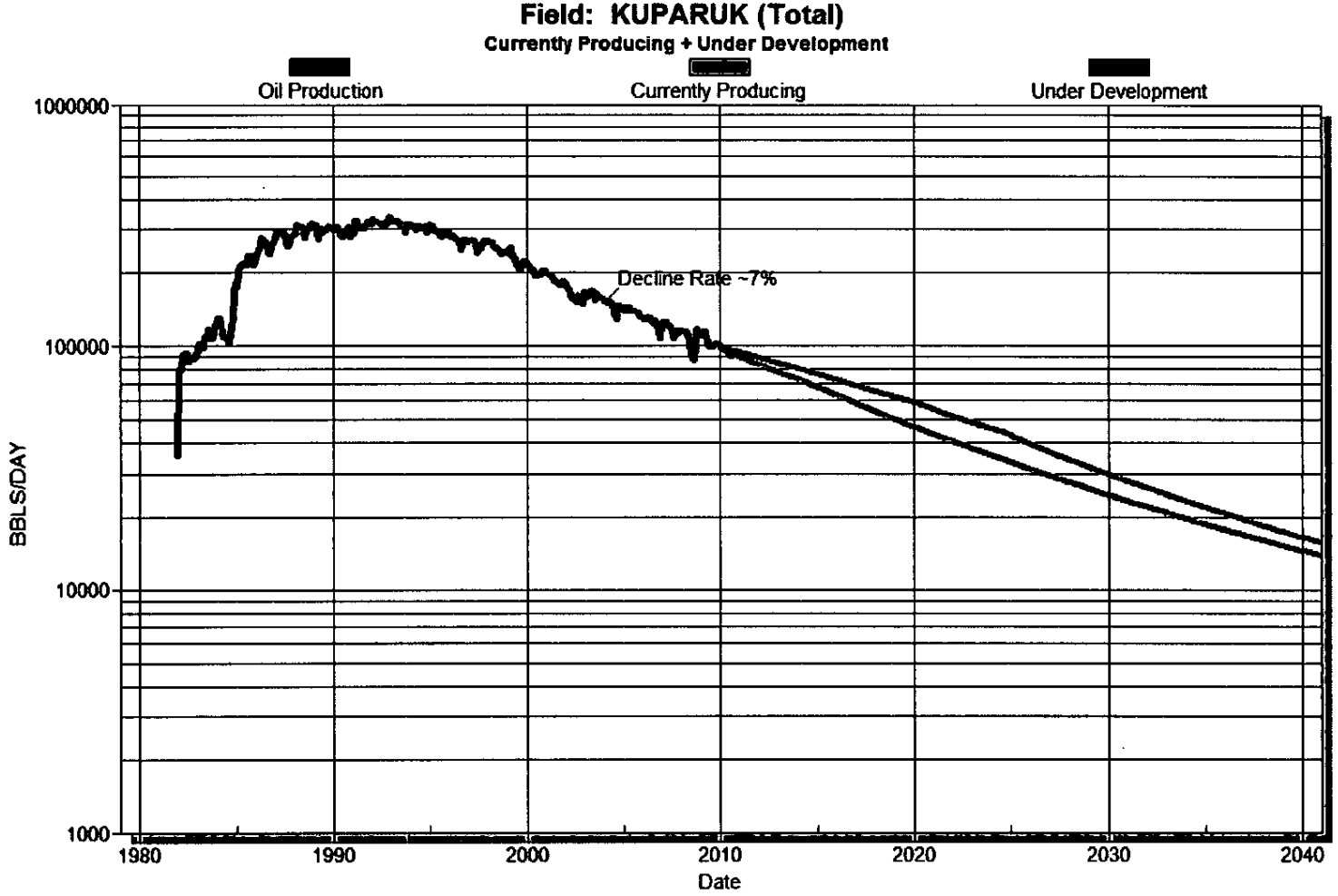
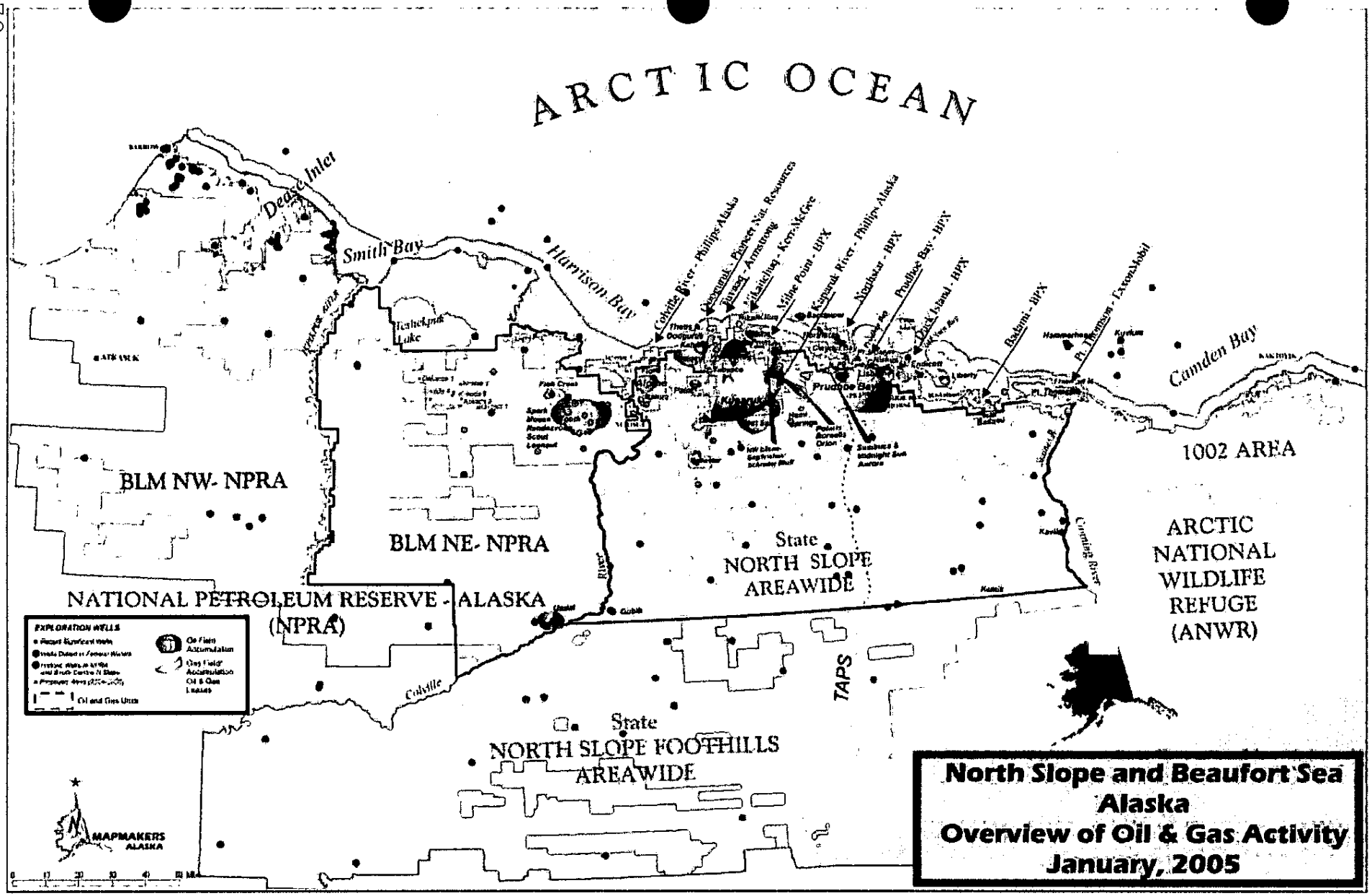
*Excludes NGLs

Kuparuk
Currently Producing + Under Dev

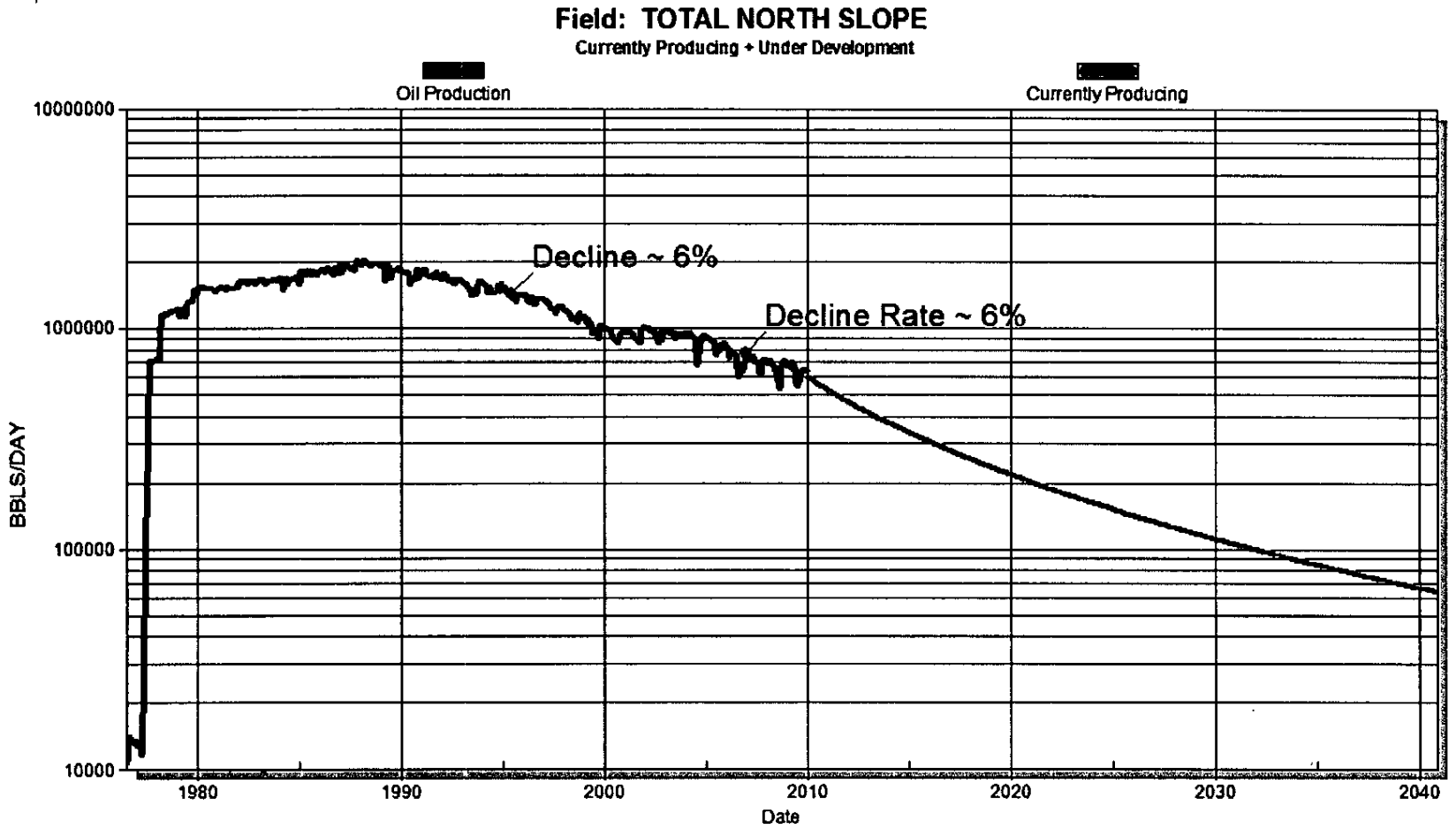


Operator: CONOCOPHILLIPS ALASKA INC
Field: KUPARUK RIVER
Reservoir: KUPARUK RIVER OIL

Cum Oil [bbls]: 2,187,540,707
Cum Gas [mcf]: 2,848,697,633
Cum Water [bbls]: 3,405,683,198


ARCTIC OCEAN
Dease Inlet
Smith Bay
Harrison Bay
Colville River - Phillips Alaska
Tarn - Pioneer Nat. Resources
Tarung - Armstrong
Alpine Point - BPX
Kuparuk River - Phillips Alaska
Meltwater - BPX
Prudhoe Bay - BPX
Duck Island - BPX
Badami - BPX
Pt. Thomson - ExxonMobil
Camden Bay
Teshekpuk Lake
Prudhoe Bay
BLM NW- NPRA
BLM NE- NPRA
NATIONAL PETROLEUM RESERVE - ALASKA (NPRA)
State NORTH SLOPE AREAWIDE
1002 AREA
ARCTIC NATIONAL WILDLIFE REFUGE (ANWR)
TAPS
Colville
State NORTH SLOPE FOOTHILLS AREAWIDE
EXPLORATION WELLS
Oil Field Accumulation
Gas Field/ Accumulation Oil & Gas Leases
Oil and Gas Units
MAPMAKERS ALASKA
North Slope and Beaufort Sea
Alaska
Overview of Oil & Gas Activity
January, 2005

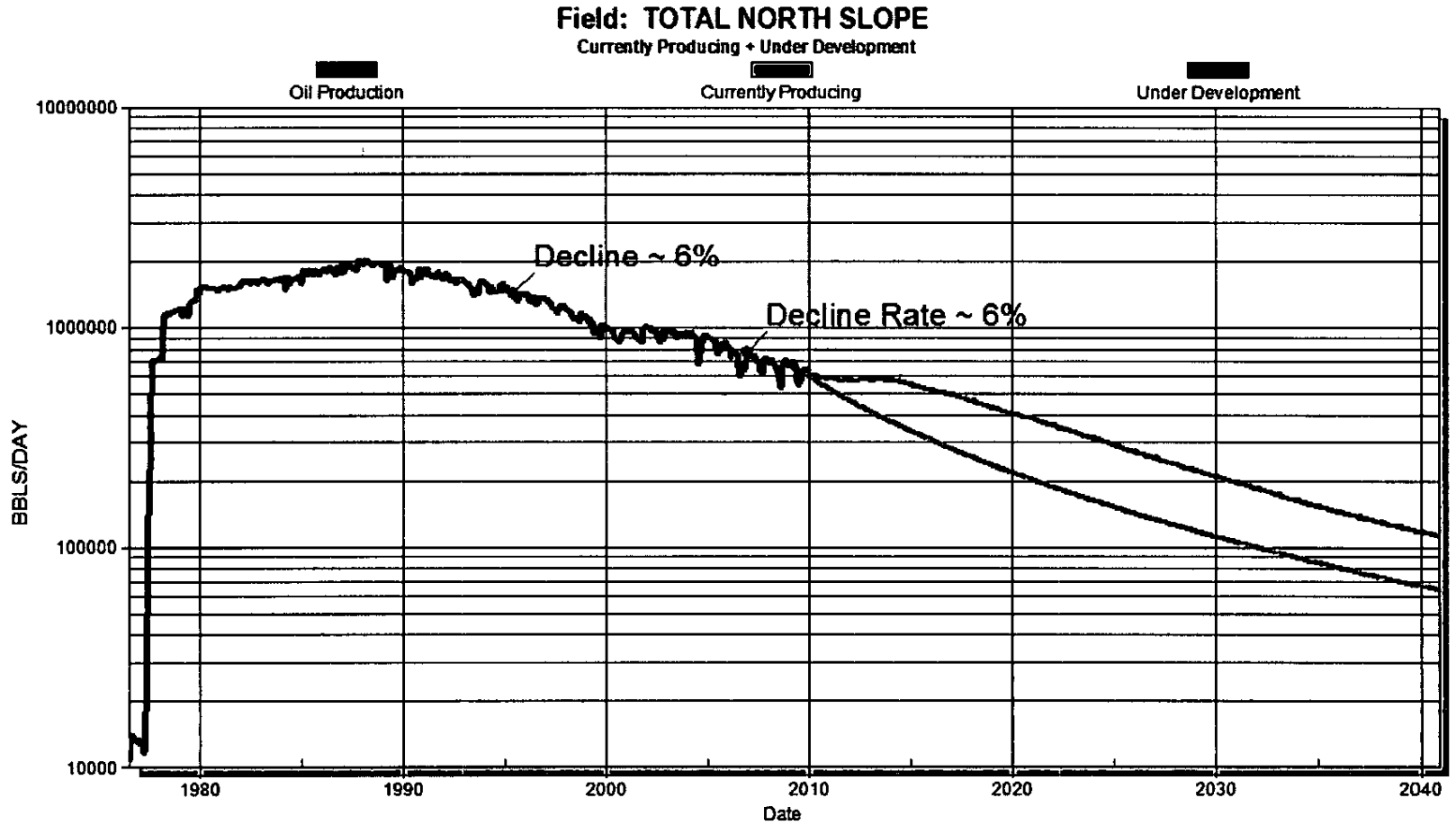
Total North Slope



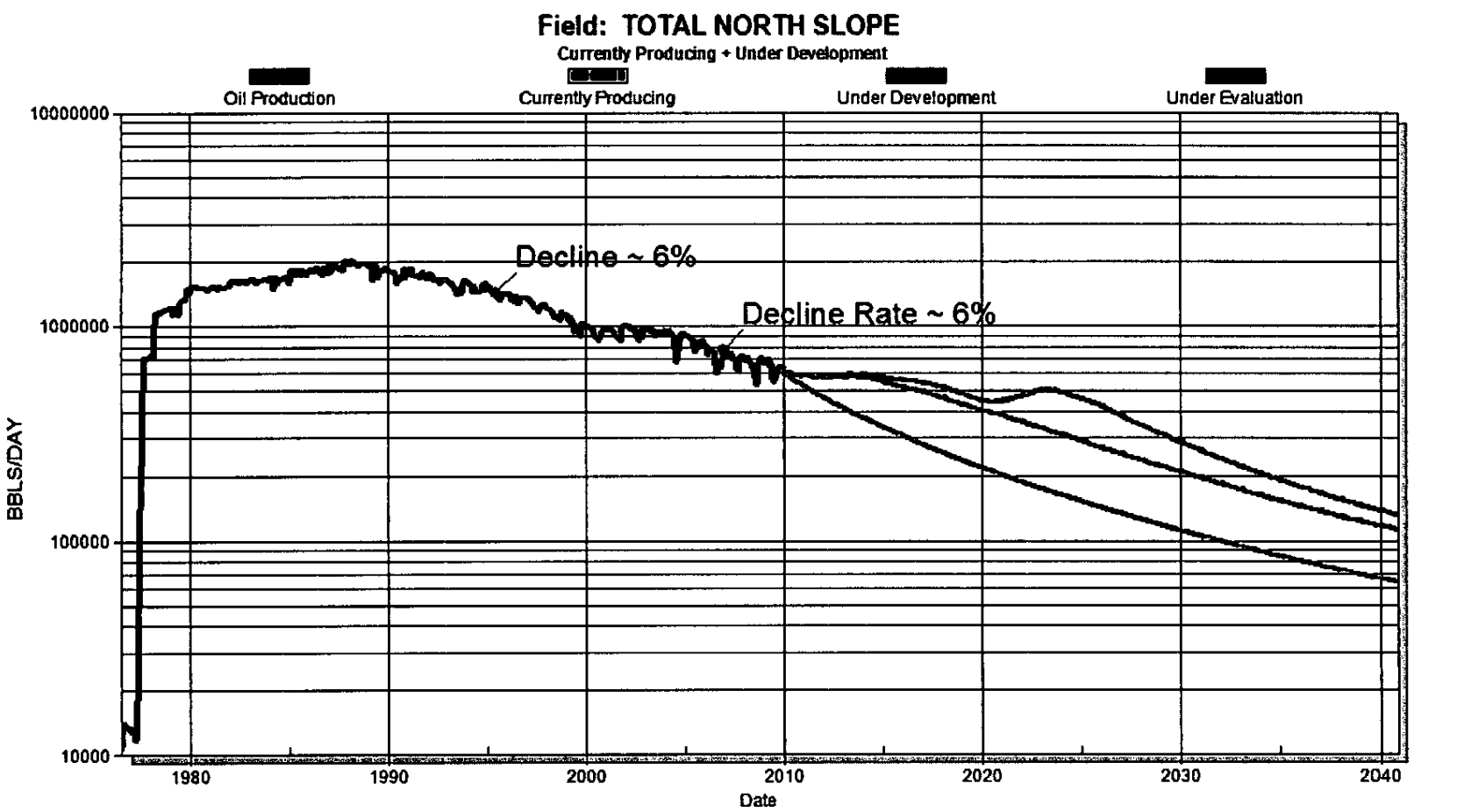
Operator:
Field:
Reservoir:

Cum Oil [bbls]: 15,603,233,666
Cum Gas [mcf]: 71,639,348,077
Cum Water [bbls]: 14,793,483,189
*Excludes NGLs

Total North Slope
Currently Producing + Under Dev.



Total North Slope
CP + UD + UE



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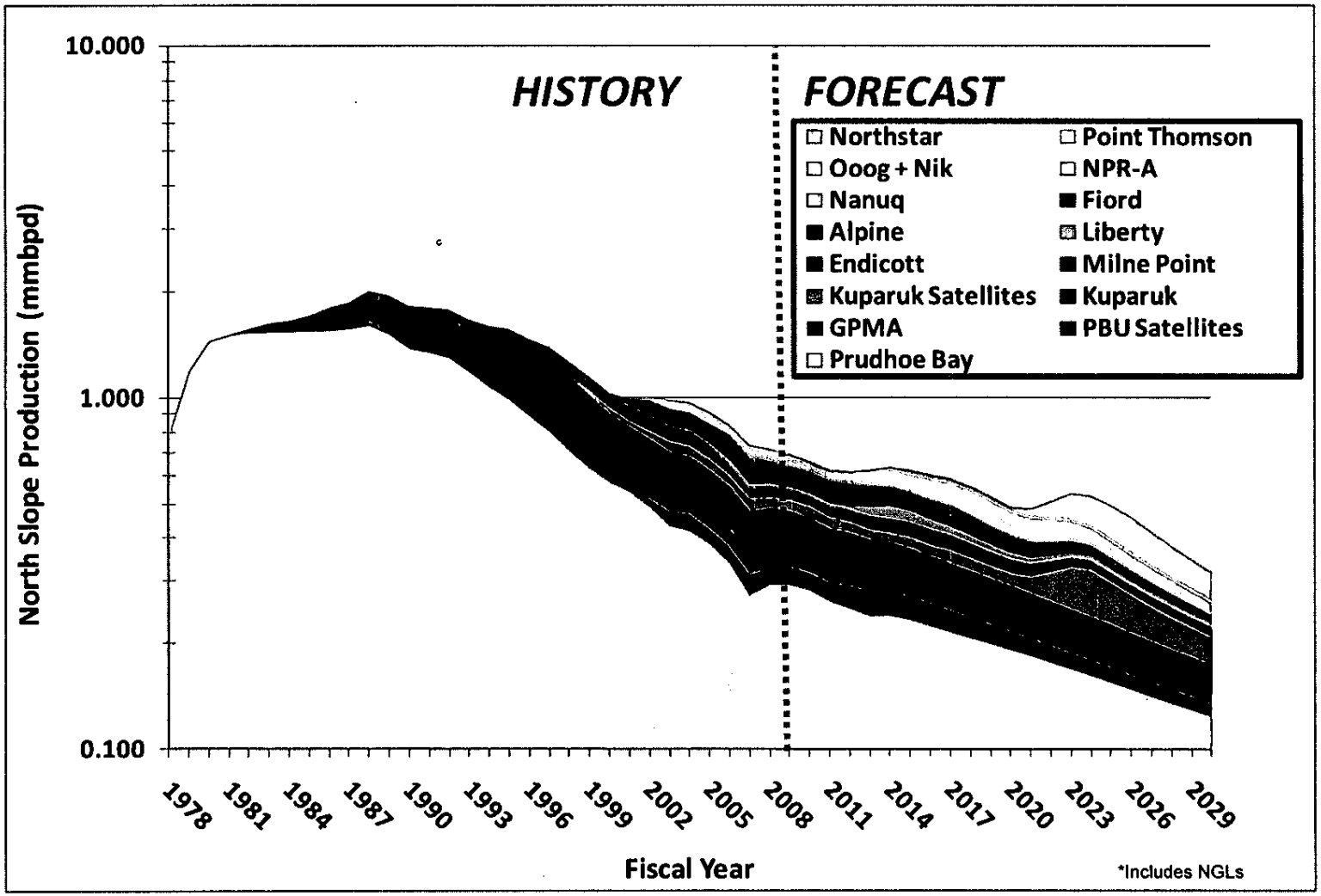
Fall 2009 Forecast: Log Scale



Conclusion

- Production forecasting requires consideration of each project's geology, development plans, commerciality, production profiles, decline curves and timing.

- Department uses extensive well and field specific data acquired from producers, AOGCC, and DNR

- Forecast is a roll up of fields that have been discovered that are currently producing, under development, and under evaluation.


3

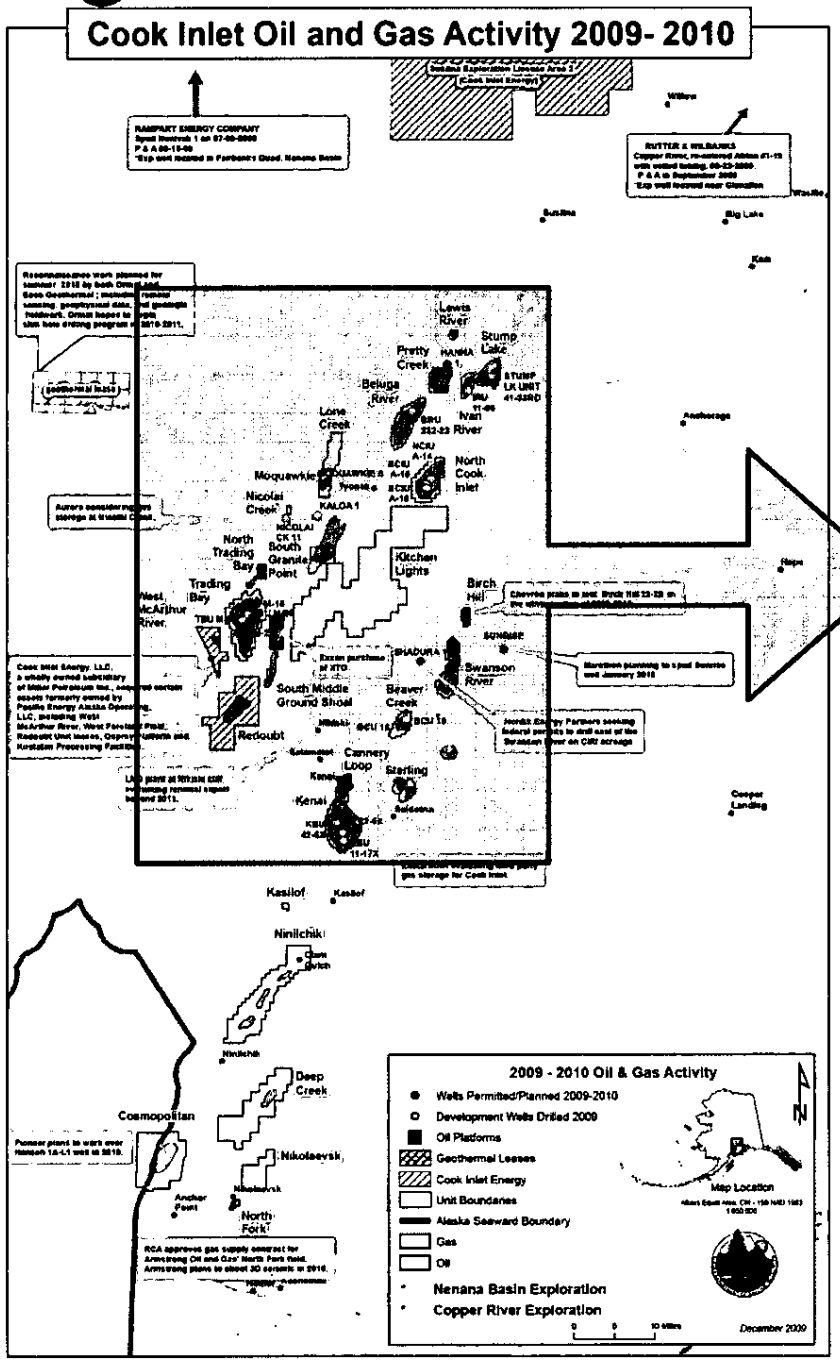
Oil and Gas Activity in Alaska 2009-2010

Senate Finance February 16, 2010

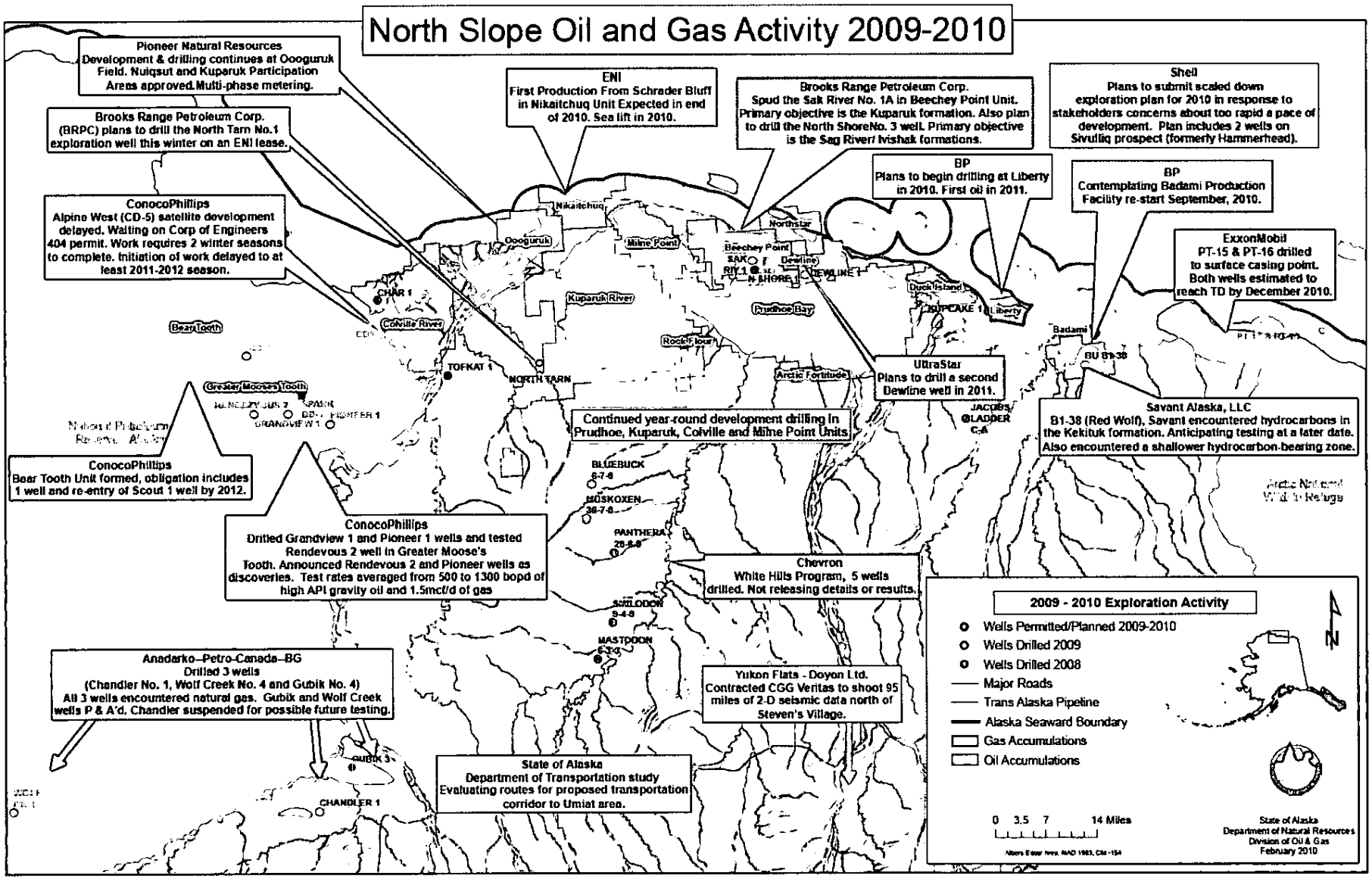
DNR: Division of Oil and Gas

Kevin Banks, *Director*

Cook Inlet Oil and Gas Activity 2009- 2010



North Slope Oil and Gas Activity 2009-2010



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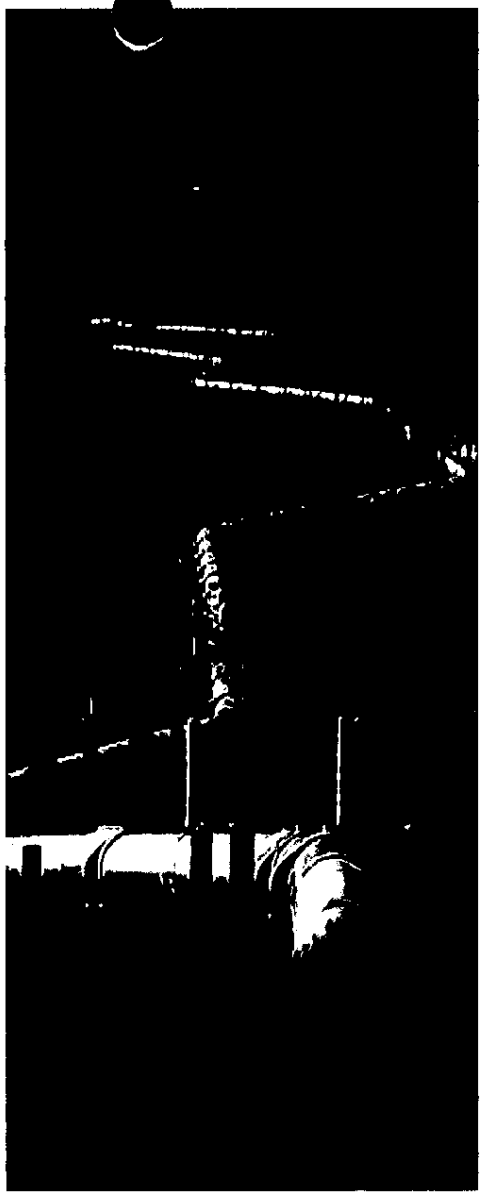


Alaska Department of Labor and Workforce Development

Oil Industry Employment, Unemployment and Resident Hire

Senate Finance Committee

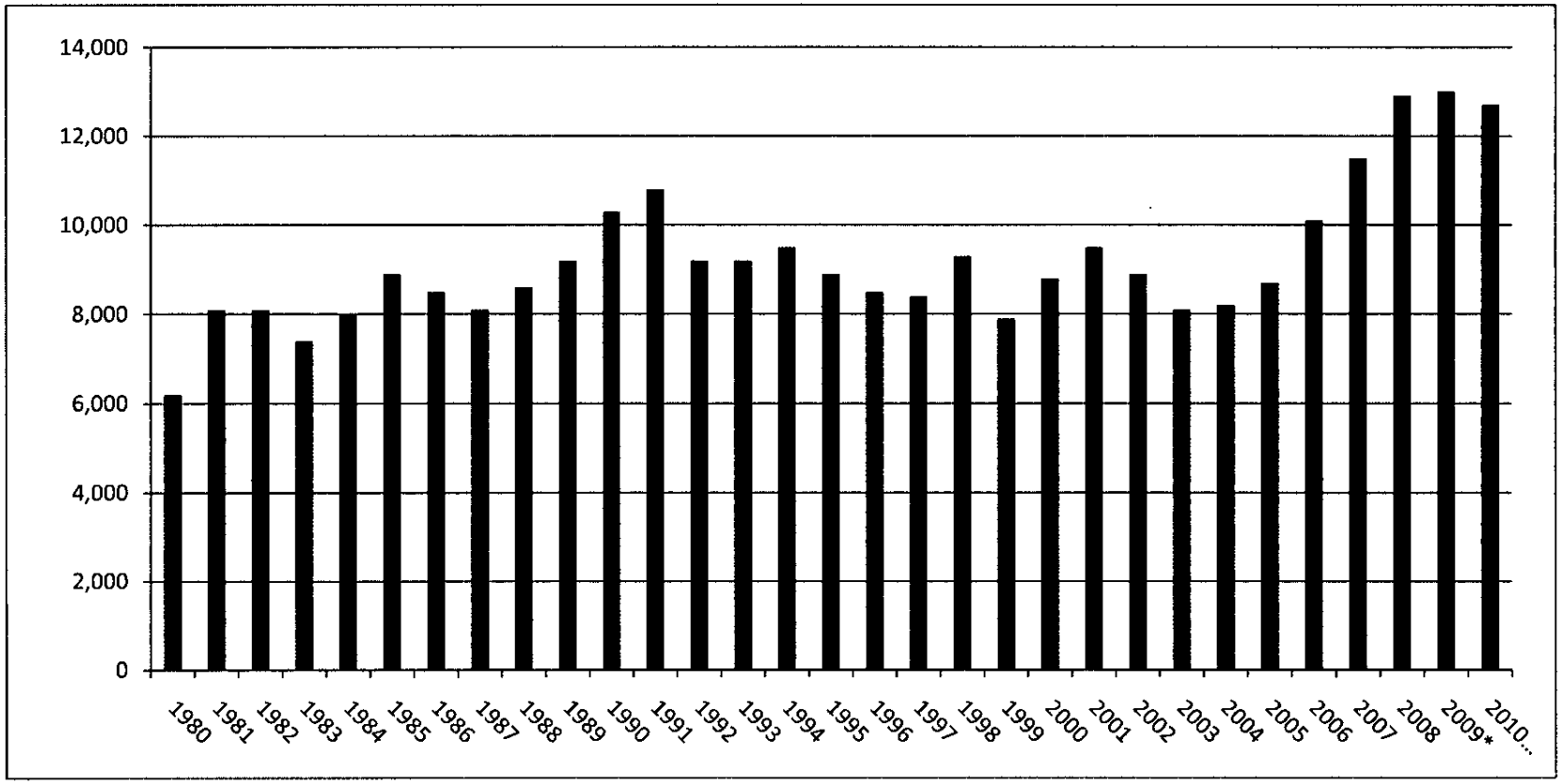
February 16, 2010

Jeff Hadland,

Economist and Research Program Supervisor

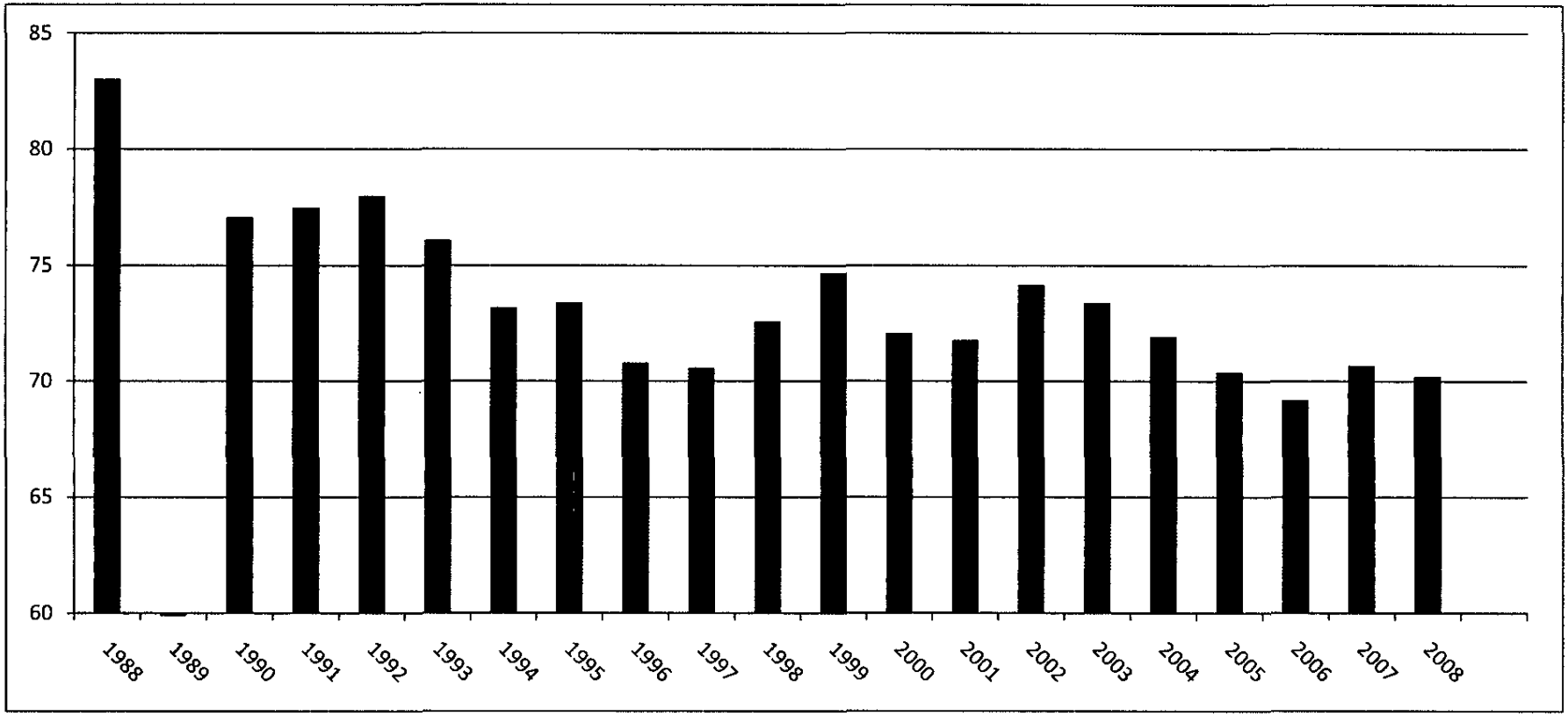
Alaska Department of Labor and Workforce Development, Research and Analysis Section

Alaska Oil and Gas Employment 1980-2010



Source: Alaska Department of Labor and Workforce Development, Research and Analysis Section

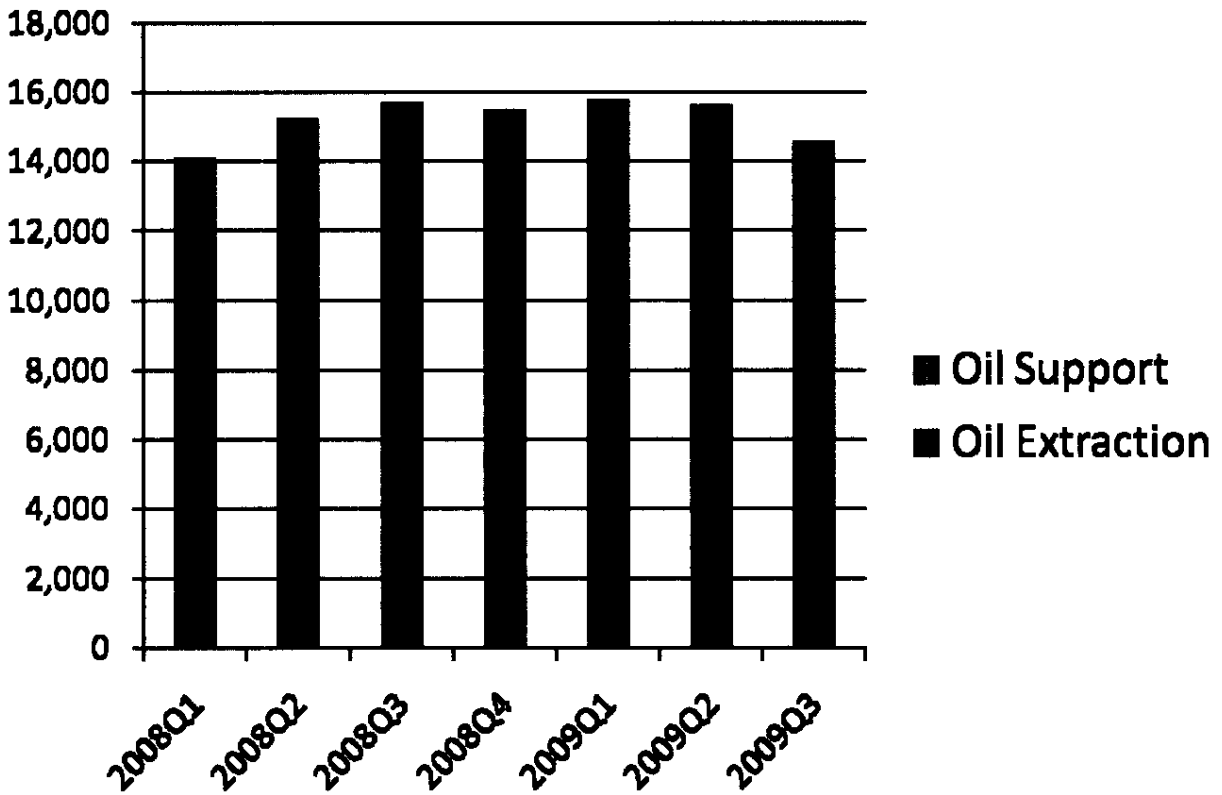
Percent Resident Workers in Oil and Gas Industry 1988-2008



Source: Alaska Department of Labor and Workforce Development, Research and Analysis Section

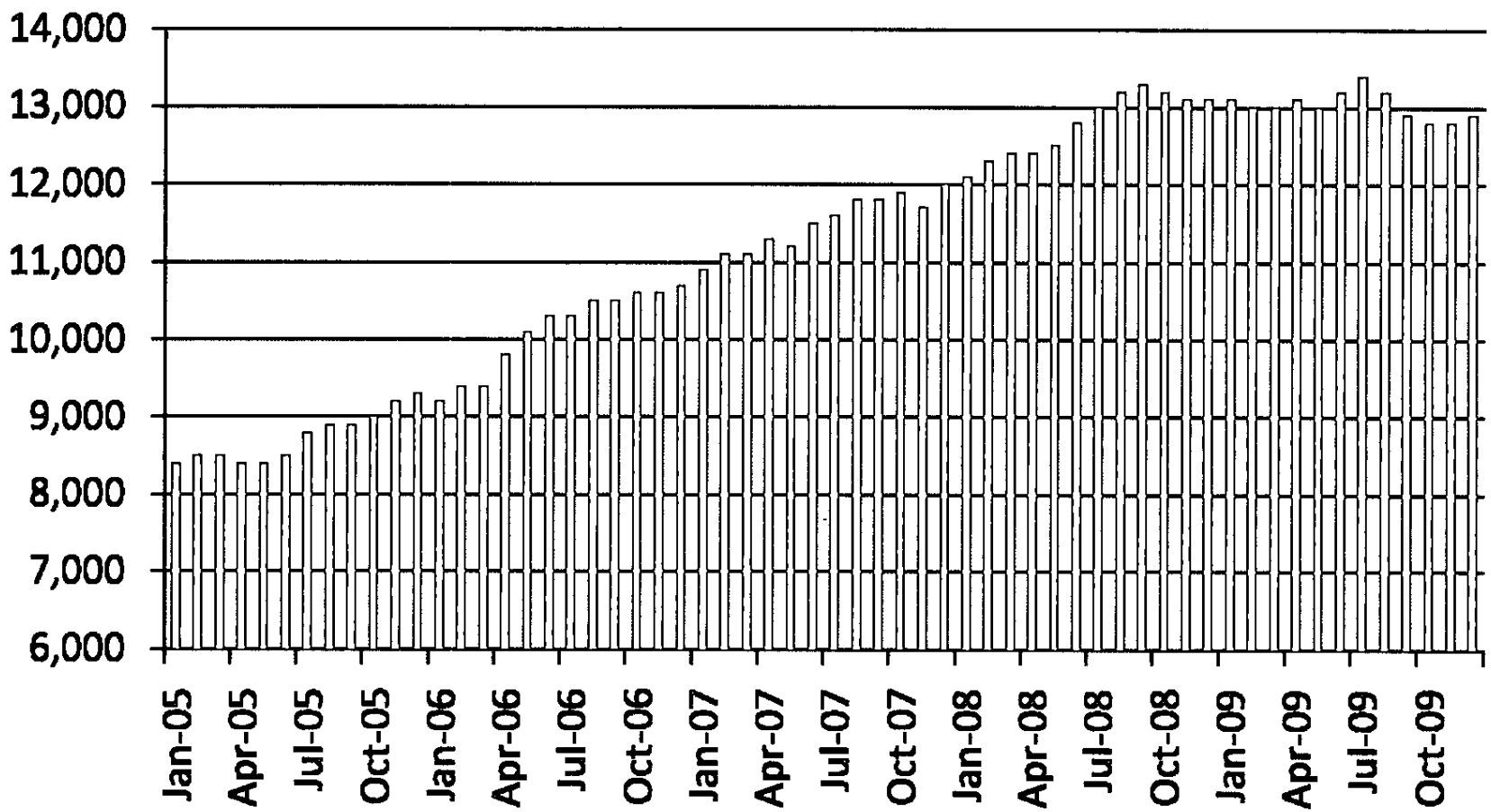
Total Workers (SSN's) Working by Quarter-Alaska Oil Industry

- Oilfield services worker count down 8.9% 2008Q3 to 2009Q3



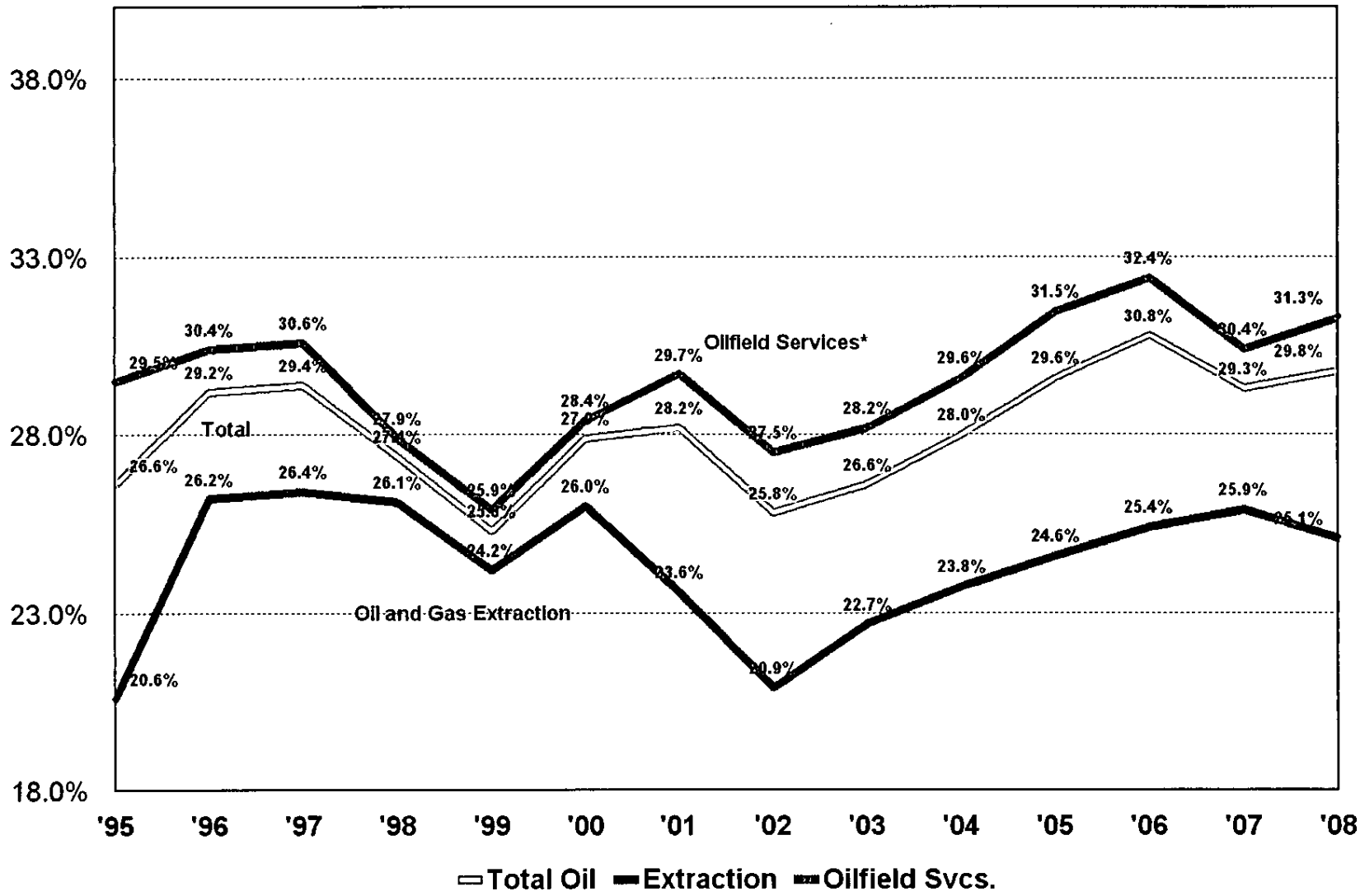
Source: Alaska Department of Labor and Workforce Development, Research and Analysis Section

Monthly Oil Industry Employment
Alaska 2005-2009



Source: Alaska Department of Labor and Workforce Development, Research and Analysis Section

Oil Industry
Percent Nonresident Workers
Alaska 1995-2008



* This industry category includes support activities for oil and gas drilling and related operations.
Note: Private Sector Only
Source: Alaska Department of Labor and Workforce Development, Research and Analysis Section

Unemployment Insurance Claimants

UI Claimants by Industry, CY2003-CY2009

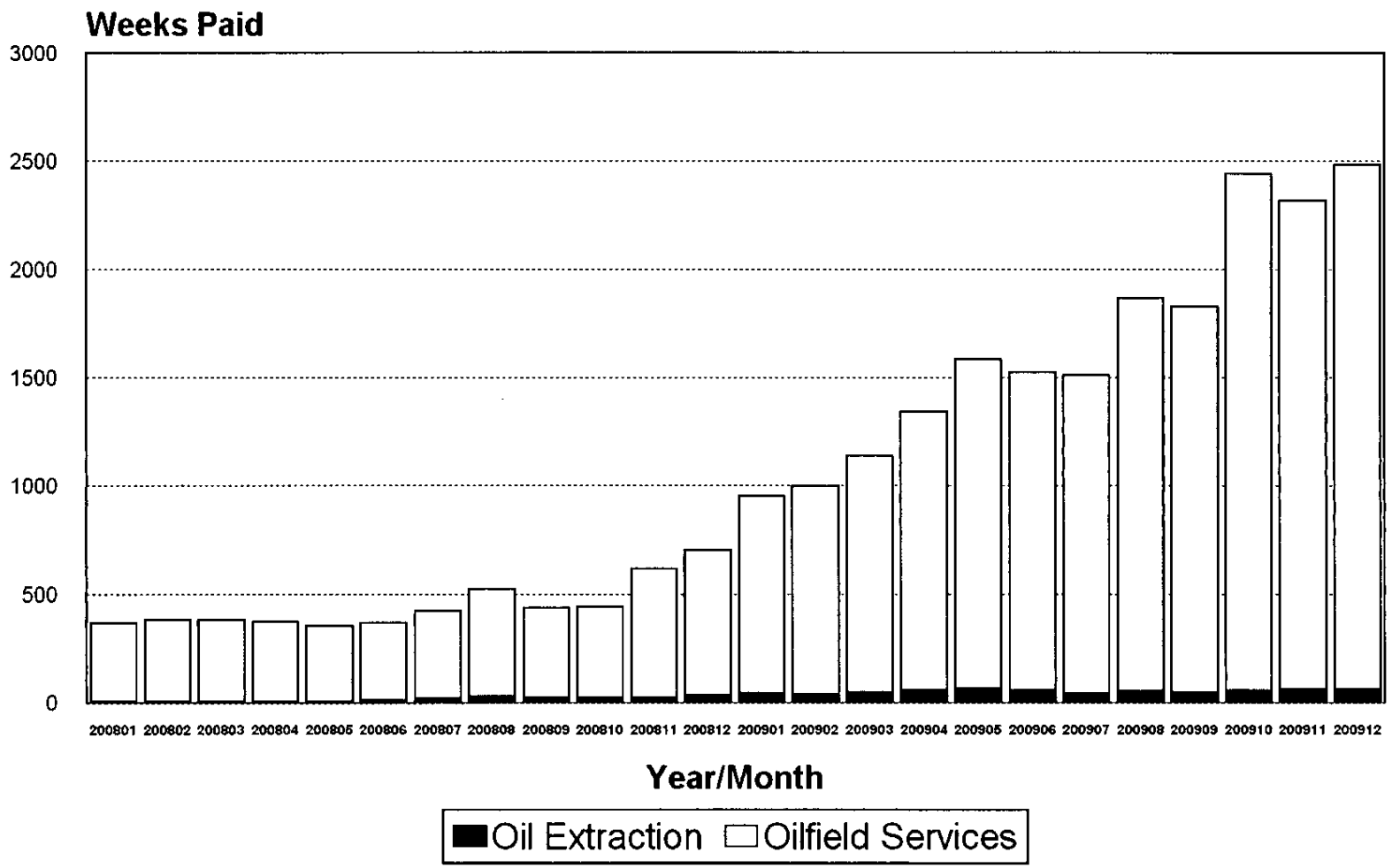
Sector Name	2003	2004	2005	2006	2007	2008	2009
All Oil and Gas Industry related employment	**2,827**	**1,732**	**1,199**	**906**	**1,084**	**1,362**	**2,844**
In-State Claimants	2,316	1,426	1,028	795	928	1,208	2,331
Inter-State Claimants	511	306	171	111	156	154	513
All Industries	**64,071**	**61,544**	**53,053**	**51,597**	**47,776**	**45,343**	**63,630**
In-State Claimants	53,084	51,045	44,194	43,156	39,999	38,189	52,371
Inter-State Claimants	10,987	10,499	8,859	8,441	7,777	7,154	11,259

Source: Alaska Department of Labor and Workforce Development, Research and Analysis Section.

UI Claimants are defined as a count of individuals that formerly worked for employers classified in the industry sector of note, who collected at least one (1) week of Unemployment Insurance durring the given year. This includes both In-state as well as Inter-state claimants, and no individual is counted twice within one year. All Industries totals may not equal the sum of individual industries as Unclassified claimants are not included in the Industry breakouts.

Alaska Unemployment Insurance Weeks Paid by Month
2008-2009

(Preliminary)



Source: Alaska Department of Labor and Workforce Development, Research and Analysis Section

Click Bishop
Commissioner
P.O. Box 111149
Juneau, AK 99811-1149
www.labor.alaska.gov

STATE OF ALASKA
DEPARTMENT OF LABOR
AND WORKFORCE DEVELOPMENT

Beth Leschper
Communications Director
907.465.2700
cell: 907.723.1321
beth.leschper@alaska.gov

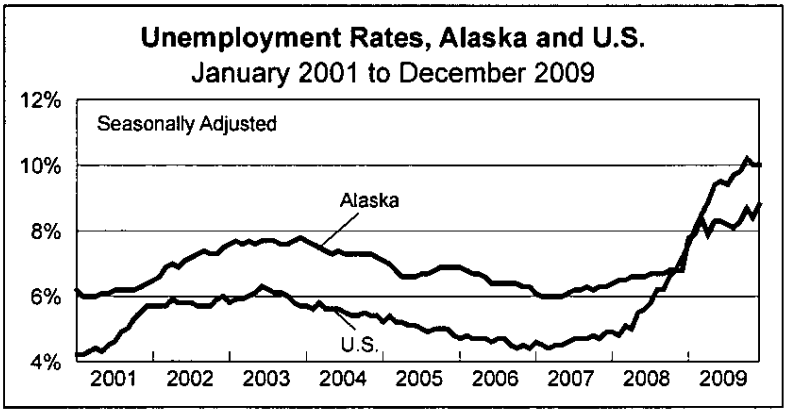
Press Release

COMMISSIONER'S OFFICE

January 22, 2010

No. 10-06

Unemployment rate at 8.8 percent in December



Alaska Nonfarm Payroll Employment[1]

	Preliminary 12/09	Revised 11/09	Revised 12/08	Changes from 11/09	Changes from 12/08
Total Nonfarm Employment[2]	306,500	310,500	309,200	-4,000	-2,700
Mining and Logging	15,100	15,200	15,700	-100	-600
Oil and Gas	12,900	12,800	13,100	100	-200
Construction	14,000	15,000	15,200	-1,000	-1,200
Manufacturing	6,600	9,500	7,200	-2,900	-600
Seafood Processing	3,300	5,000	3,400	-1,700	-100
Trade, Transportation and Utilities	61,900	61,700	63,200	200	-1,300
Retail Trade	35,500	35,500	36,500	0	-1,000
Information	6,800	6,800	7,100	0	-300
Financial Activities	14,200	14,300	14,600	-100	-400
Professional and Business Services	24,500	24,700	24,700	-200	-200
Educational[3] and Health Services	39,600	39,500	37,600	100	2,000
Health Care	28,700	28,600	27,300	100	1,400
Leisure and Hospitality	26,600	27,000	28,200	-400	-1,600
Accommodations	6,000	6,100	6,600	-100	-600
Food Svcs. and Drinking Places	16,800	17,000	17,800	-200	-1,000
Other Services	11,400	11,500	11,400	-100	0
Government[4]	85,800	85,300	84,300	500	1,500

[1] Not seasonally adjusted
[2] Excludes the self-employed, fishermen and other agricultural workers, and private household workers
[3] Private education only
[4] Includes public schools, the University of Alaska and federally recognized tribal entities

Unemployment Rates, Seasonally Adjusted

	12/09	11/09	12/08
Alaska	8.8%	8.4%	6.8%
U.S.	10.0%	10.0%	7.4%

Sources for graph and tables: Alaska Department of Labor and Workforce Development, Research and Analysis Section; and U.S. Bureau of Labor Statistics

Alaska's December seasonally adjusted unemployment rate was 8.8 percent. November's preliminary rate was revised down three-tenths of a percentage point to 8.4 percent.

The comparable national unemployment rate for December was 10.0 percent.

That marks the 12th month Alaska's rate has remained below the nation's. The last time that happened was in the early 1980s when the U.S. was in the midst of a very deep recession and Alaska was in the middle of an economic boom.

All the state's regions saw higher over-the-year unemployment rates in December. In Southeast, the rates were higher because of employment losses in leisure and hospitality, construction and retail. In the Gulf Coast, it was losses in the oil, and leisure and hospitality industries. In the Northern region, declines in the oil industry took their toll. In the Interior and Anchorage/Mat-Su regions, a long list of industries contributed to higher unemployment.

Another factor contributing to the rising jobless rate is the growth in the number of job seekers. Because Alaska's relative employment picture remains better than most of the nation's, fewer Alaskans are leaving the state looking for employment prospects elsewhere in the country and more job seekers are coming north looking for employment opportunities.

In December, over-the-month and over-the-year wage and salary employment were down. The seasonal losses in December are typical, led by seasonal losses in seafood processing, construction, and leisure and hospitality.

December marks the ninth month in a row of over-the-year employment losses. As 2009 progressed, the number of industries with employment losses grew. By December only educational and health services – more specifically health care and social assistance – and government remained positive.

Contact: Neal Fried, Economist (907) 269-4861
Research and Analysis' Web site: laborstats.alaska.gov

Labor Force by Borough and Census Area, Not Seasonally Adjusted[1]

	Civilian Labor Force			Unemployed					
				Number			Rate		
	12/09P	11/09	12/08	12/09P	11/09	12/08	12/09P	11/09	12/08
Alaska Statewide	**354,603**	**355,153**	**356,301**	**31,842**	**29,275**	**27,051**	**9.0**	**8.2**	**7.6**
Anchorage/Mat-Su Region	199,925	199,402	200,875	15,383	14,368	12,715	7.7	7.2	6.3
Municipality of Anchorage	157,710	157,531	158,621	10,978	10,407	9,012	7.0	6.6	5.7
Matanuska-Susitna Borough	42,215	41,871	42,254	4,405	3,961	3,703	10.4	9.5	8.8
Gulf Coast Region	**36,205**	**36,603**	**35,764**	**4,559**	**4,113**	**3,752**	**12.6**	**11.2**	**10.5**
Kenai Peninsula Borough	25,944	25,881	25,308	3,191	2,901	2,524	12.3	11.2	10.0
Kodiak Island Borough	5,939	6,217	5,802	831	713	711	14.0	11.5	12.3
Valdez-Cordova Census Area	4,322	4,505	4,654	537	499	517	12.4	11.1	11.1
Interior Region	**52,081**	**52,458**	**53,277**	**4,760**	**4,381**	**4,194**	**9.1**	**8.4**	**7.9**
Denali Borough	846	824	927	162	150	144	19.1	18.2	15.5
Fairbanks North Star Borough	44,727	44,850	45,830	3,718	3,439	3,255	8.3	7.7	7.1
Southeast Fairbanks Census Area	3,586	3,723	3,666	416	365	365	11.6	9.8	10.0
Yukon-Koyukuk Census Area	2,922	3,061	2,854	464	427	430	15.9	13.9	15.1
Northern Region	**12,666**	**12,591**	**12,370**	**1,144**	**1,096**	**923**	**9.0**	**8.7**	**7.5**
Nome Census Area	4,133	4,133	4,010	487	460	413	11.8	11.1	10.3
North Slope Borough	5,553	5,468	5,376	279	286	199	5.0	5.2	3.7
Northwest Arctic Borough	2,980	2,990	2,984	378	350	311	12.7	11.7	10.4
Southeast Region	**38,078**	**37,682**	**38,123**	**3,627**	**3,191**	**3,197**	**9.5**	**8.5**	**8.4**
Haines Borough	1,091	1,122	1,102	142	127	134	13.0	11.3	12.2
Juneau Borough	18,077	17,861	18,238	1,187	1,114	1,087	6.6	6.2	6.0
Ketchikan Gateway Borough[2]	7,768	7,676	7,762	772	646	587	9.9	8.4	7.6
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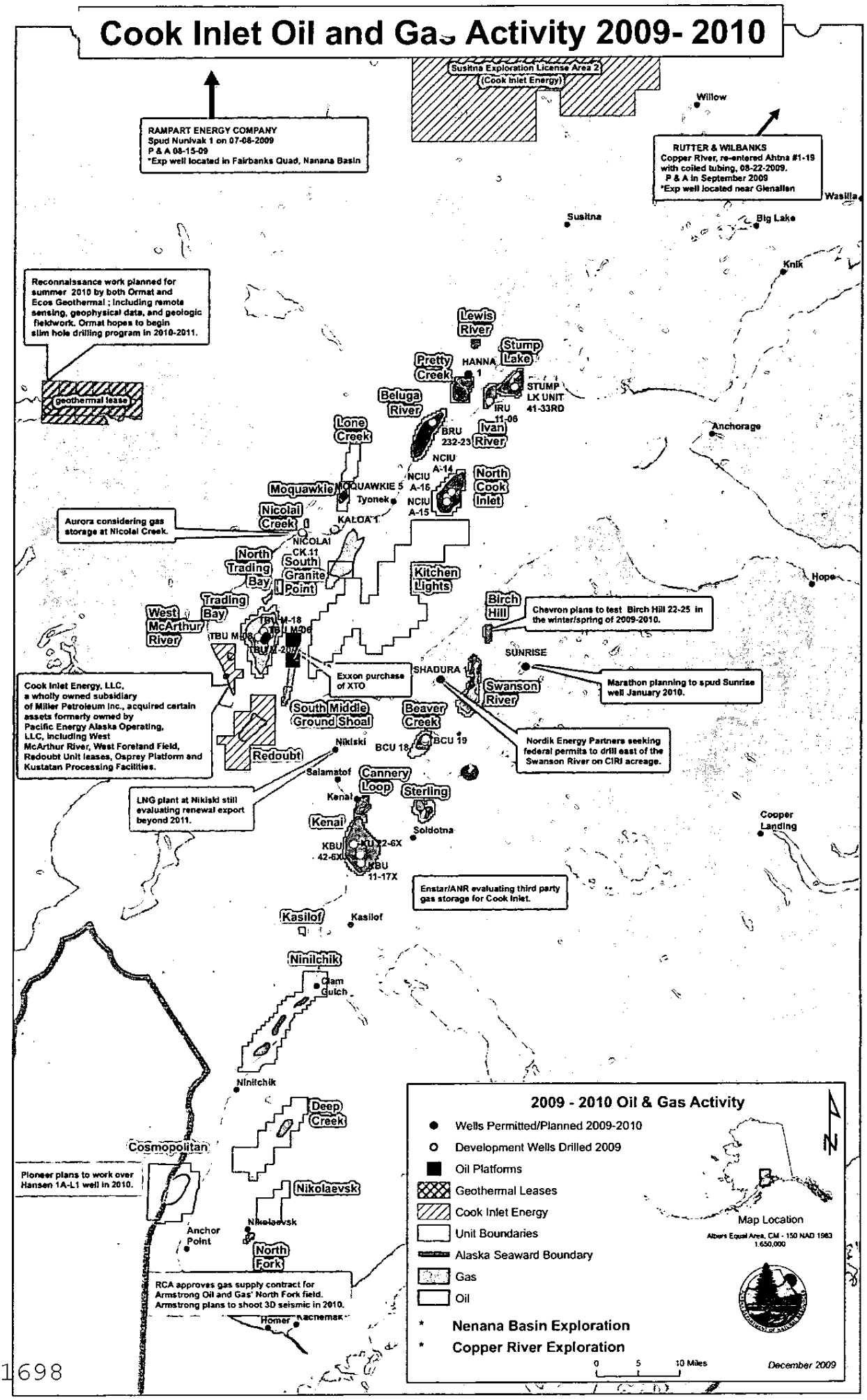
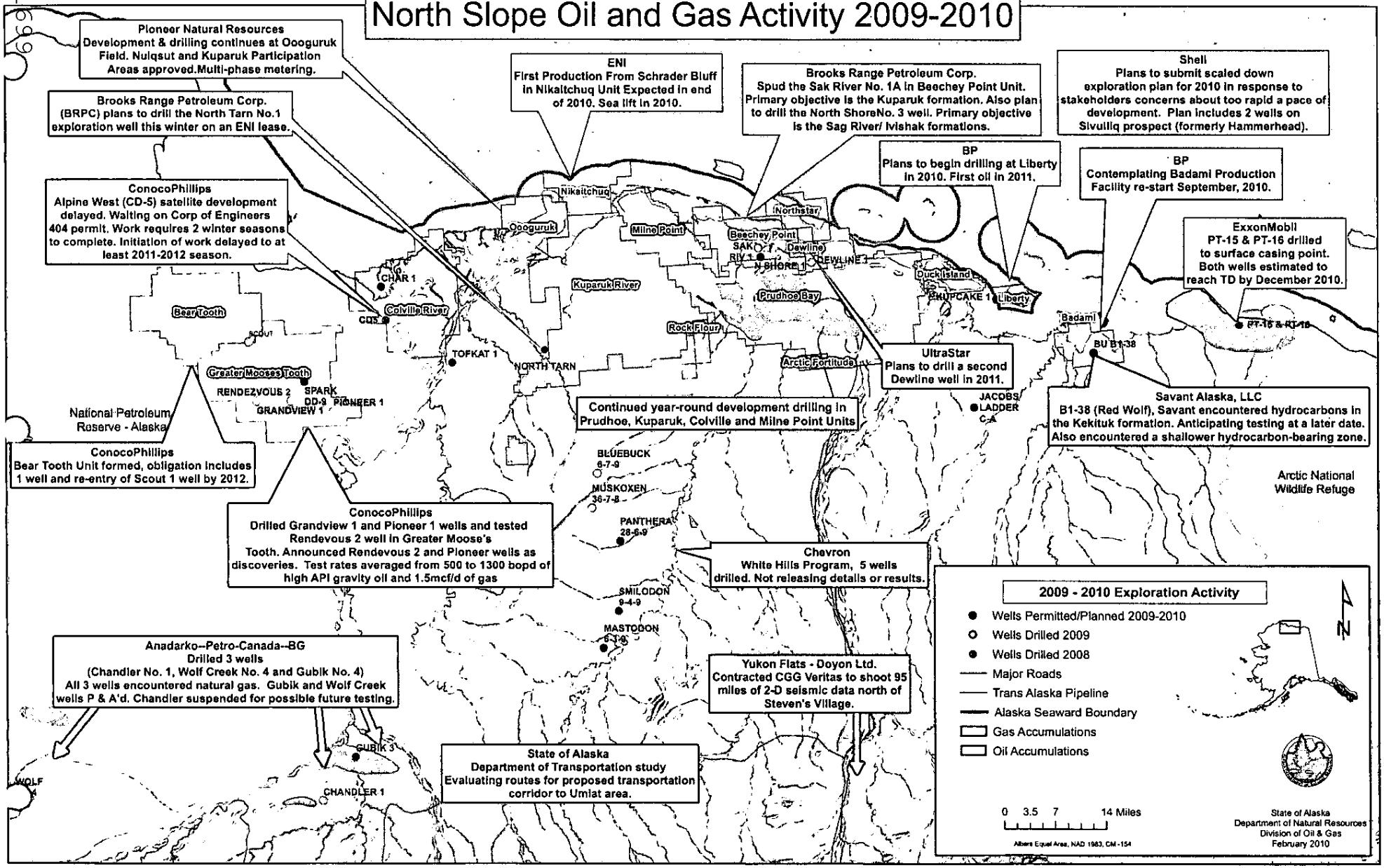

Cook Inlet Oil and Gas Activity 2009- 2010
Susitna Exploration License Area 2
(Cook Inlet Energy)
RAMPART ENERGY COMPANY
Spud Nunivak 1 on 07-08-2009
P & A 08-15-09
*Exp well located in Fairbanks Quad, Nanana Basin
RUTTER & WILBANKS
Copper River, re-entered Ahtna #1-19
with coiled tubing, 08-22-2009.
P & A in September 2009
*Exp well located near Glenallen
Willow
Wasilla
Susitna
Big Lake
Knik
Anchorage
Hope
Cooper Landing
Reconnaissance work planned for summer 2010 by both Ormat and Ecos Geothermal ; including remote sensing, geophysical data, and geologic fieldwork. Ormat hopes to begin slim hole drilling program in 2010-2011.
geothermal lease
Aurora considering gas storage at Nicolai Creek.
Cook Inlet Energy, LLC, a wholly owned subsidiary of Miller Petroleum Inc., acquired certain assets formerly owned by Pacific Energy Alaska Operating, LLC, including West McArthur River, West Foreland Field, Redoubt Unit leases, Osprey Platform and Kustatan Processing Facilities.
LNG plant at Nikiski still evaluating renewal export beyond 2011.
Exxon purchase of XTO
Chevron plans to test Birch Hill 22-25 in the winter/spring of 2009-2010.
Marathon planning to spud Sunrise well January 2010.
Nordik Energy Partners seeking federal permits to drill east of the Swanson River on CIRI acreage.
Enstar/ANR evaluating third party gas storage for Cook Inlet.
Pioneer plans to work over Hansen 1A-L1 well in 2010.
RCA approves gas supply contract for Armstrong Oil and Gas' North Fork field. Armstrong plans to shoot 3D seismic in 2010.
Lewis River
Stump Lake
Pretty Creek
HANNA 1
STUMP LK UNIT 41-33RD
Beluga River
IRU 11-06
Ivan River
Lone Creek
BRU 232-23
NCIU A-14
NCIU A-16
NCIU A-15
North Cook Inlet
Moquawkie
MOQUAWKIE 5
Tyonek
Nicolai Creek
KALOA 1
NICOLAI CK.11
North Trading Bay
South Granite Point
Kitchen Lights
Birch Hill
Trading Bay
West McArthur River
TBU M-18
TBU M-28
TBU M-20
TBU M-27
SUNRISE
SHADURA 1
Swanson River
South Middle Ground Shoal
Beaver Creek
Nikiski
BCU 18
BCU 19
Redoubt
Salamatof
Cannery Loop
Sterling
Kenai
Soldotna
KBU 42-6X
KU 22-6X
KBU 11-17X
Kasilof
Kasilof
Nanilchik
Clam Gulch
Ninilchik
Deep Creek
Cosmopolitan
Nikolaevsk
Nikolaevsk
Anchor Point
North Fork
Homer
Nachemak
2009 - 2010 Oil & Gas Activity
Wells Permitted/Planned 2009-2010
Development Wells Drilled 2009
Oil Platforms
Geothermal Leases
Cook Inlet Energy
Unit Boundaries
Alaska Seaward Boundary
Gas
Oil
* Nenana Basin Exploration
* Copper River Exploration
Map Location
Albers Equal Area, CM - 150 NAD 1983
1:650,000
0 5 10 Miles
December 2009

North Slope Oil and Gas Activity 2009-2010

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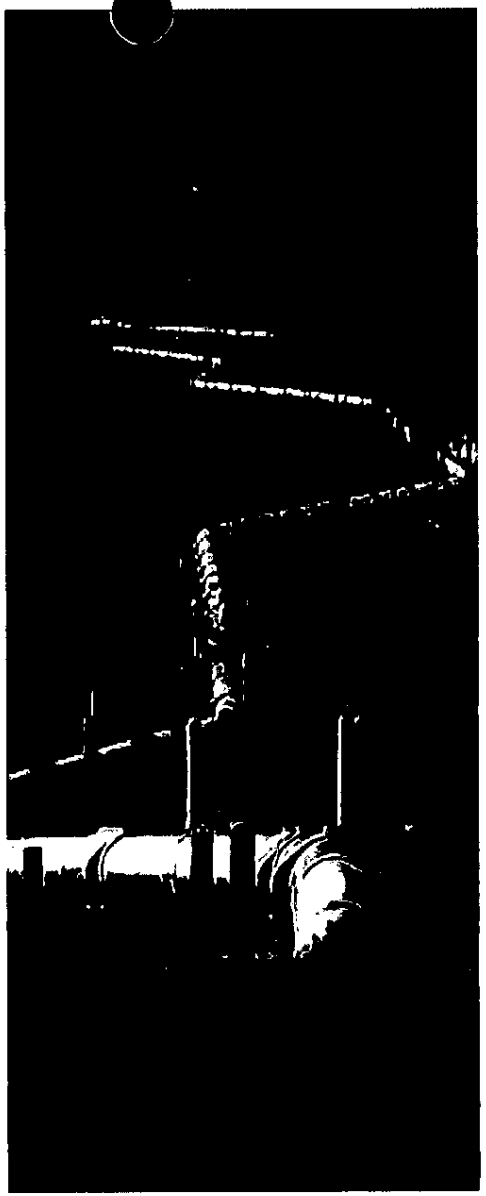


Alaska Department of Labor and Workforce Development

Oil Industry Employment, Unemployment and Resident Hire

Senate Finance Committee

February 16, 2010

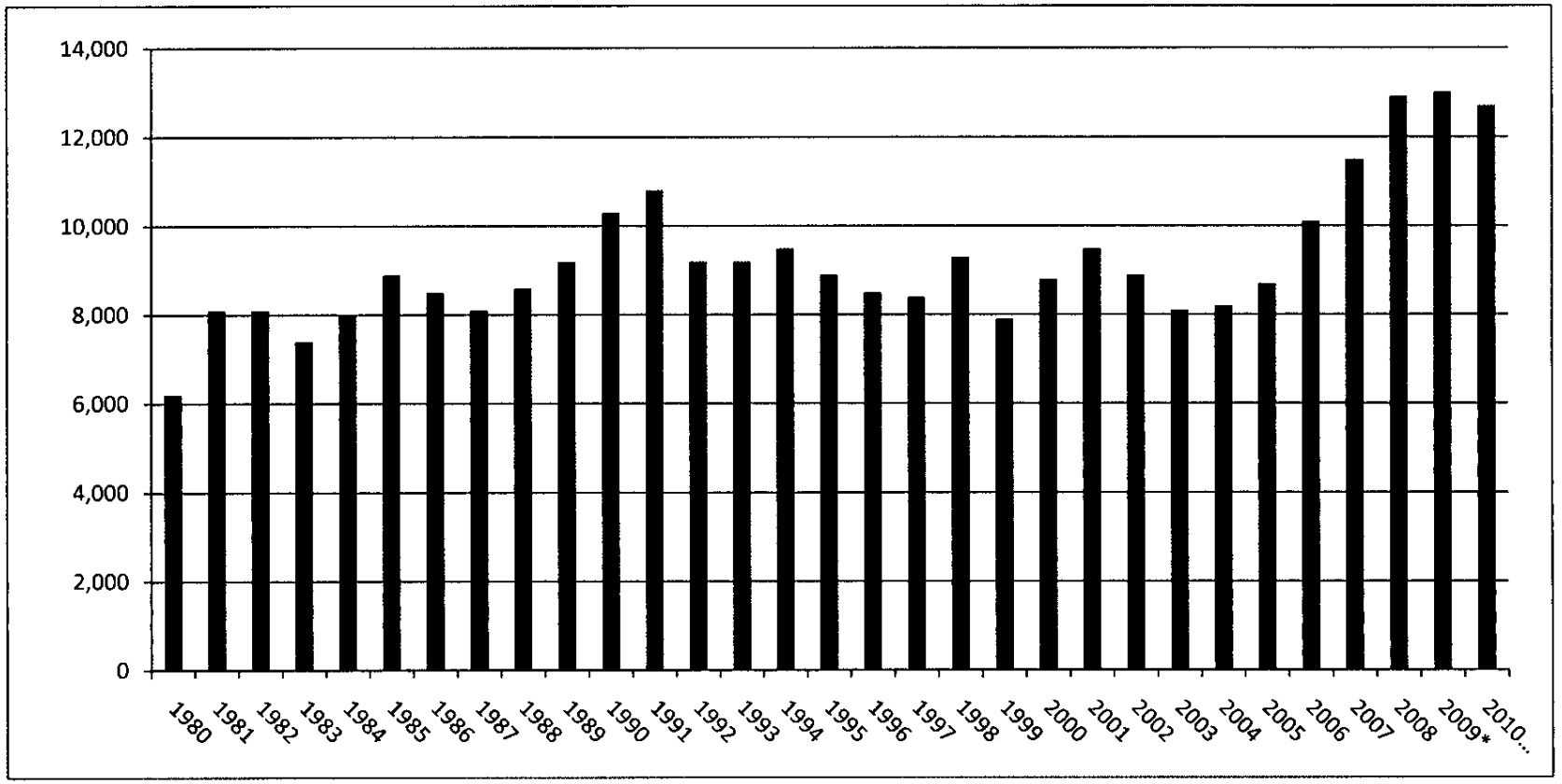
Jeff Hadland,

Economist and Research Program Supervisor

Alaska Department of Labor and Workforce Development, Research and Analysis Section

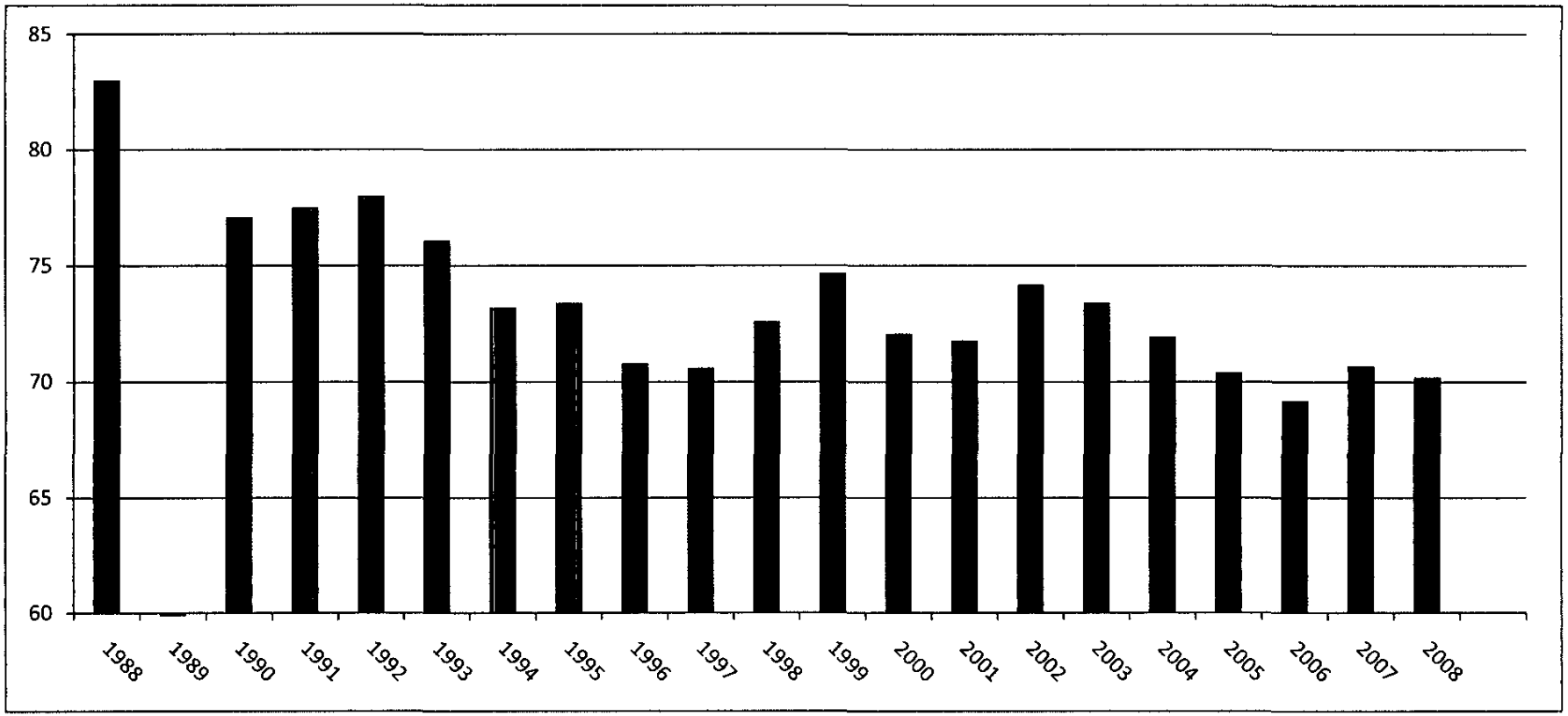
1702

Alaska Oil and Gas Employment 1980-2010



Source: Alaska Department of Labor and Workforce Development, Research and Analysis Section

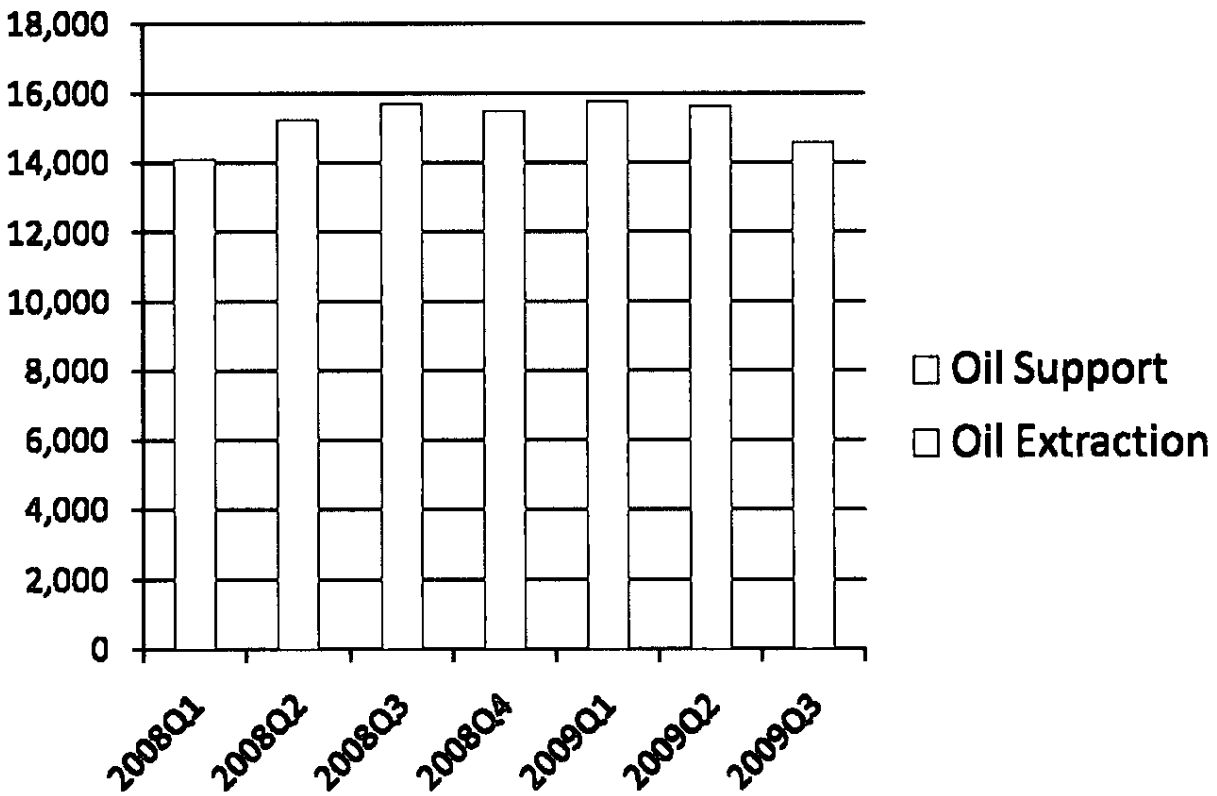
Percent Resident Workers in Oil and Gas Industry 1988-2008



Source: Alaska Department of Labor and Workforce Development, Research and Analysis Section

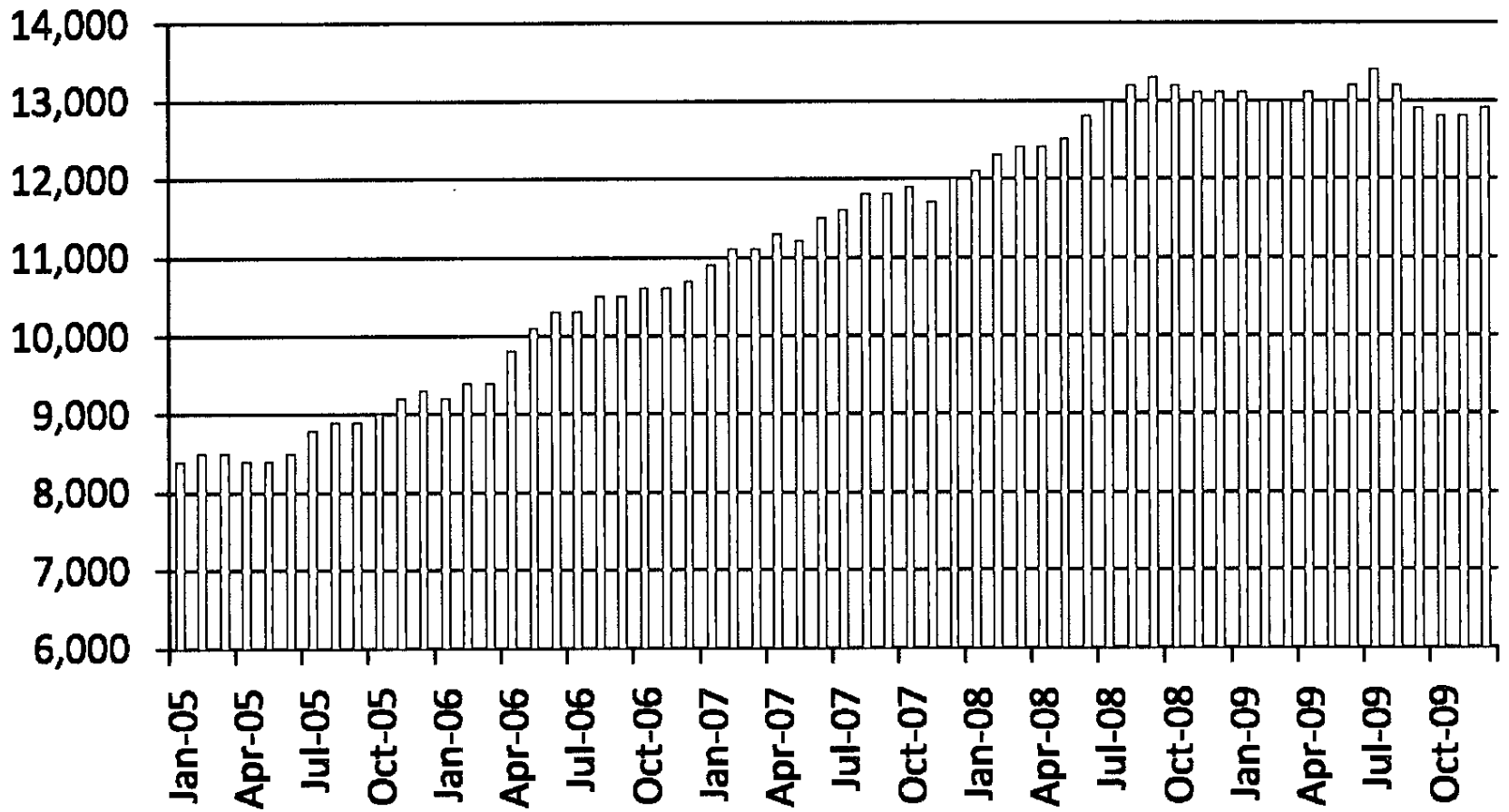
Total Workers (SSN's) Working by Quarter-Alaska Oil Industry

- Oilfield services worker count down 8.9% 2008Q3 to 2009Q3



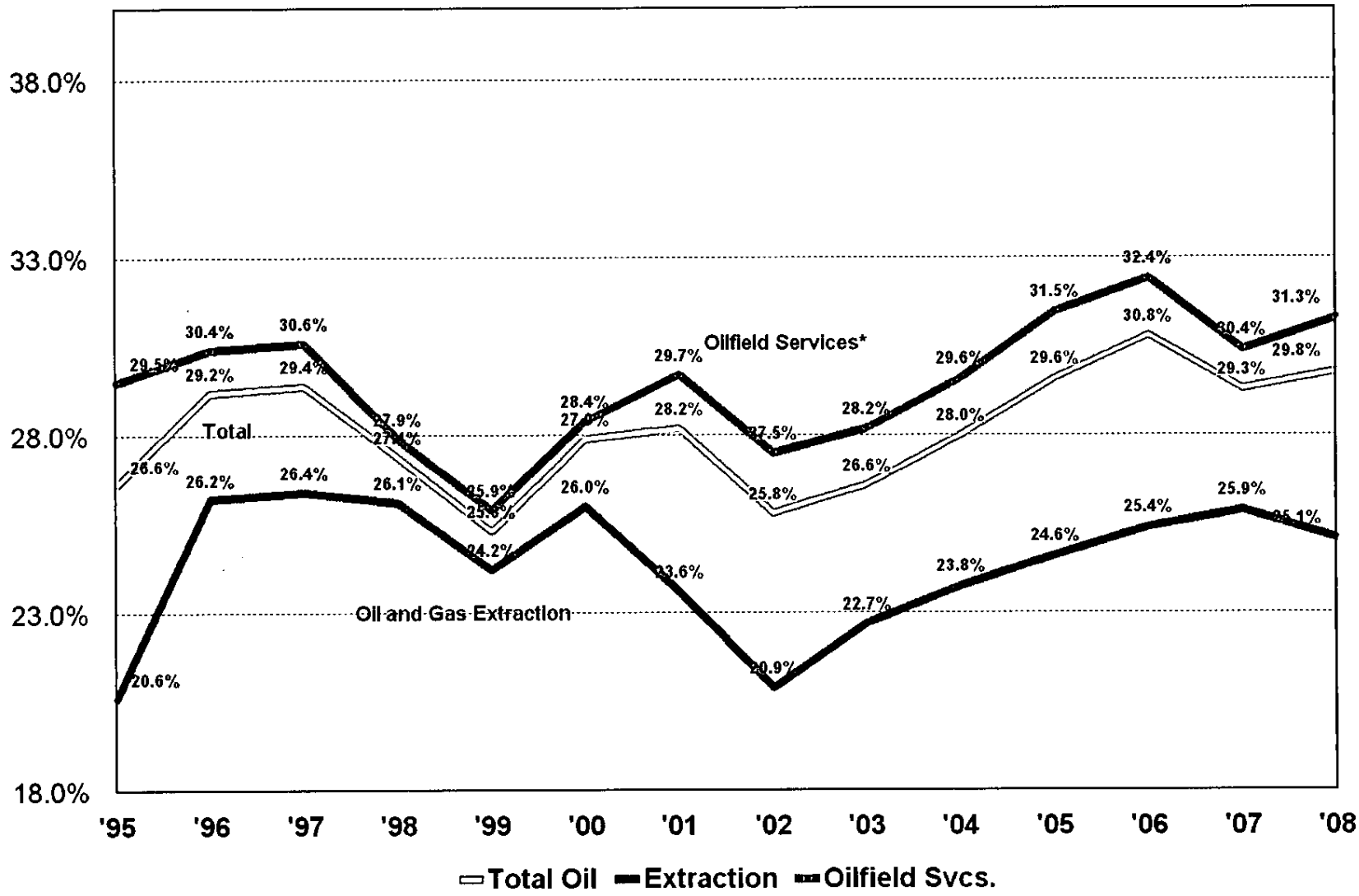
Source: Alaska Department of Labor and Workforce Development, Research and Analysis Section

Monthly Oil Industry Employment
Alaska 2005-2009



Source: Alaska Department of Labor and Workforce Development, Research and Analysis Section

Oil Industry
Percent Nonresident Workers
Alaska 1995-2008



* This industry category includes support activities for oil and gas drilling and related operations.
Note: Private Sector Only
Source: Alaska Department of Labor and Workforce Development, Research and Analysis Section

Unemployment Insurance Claimants

UI Claimants by Industry, CY2003-CY2009

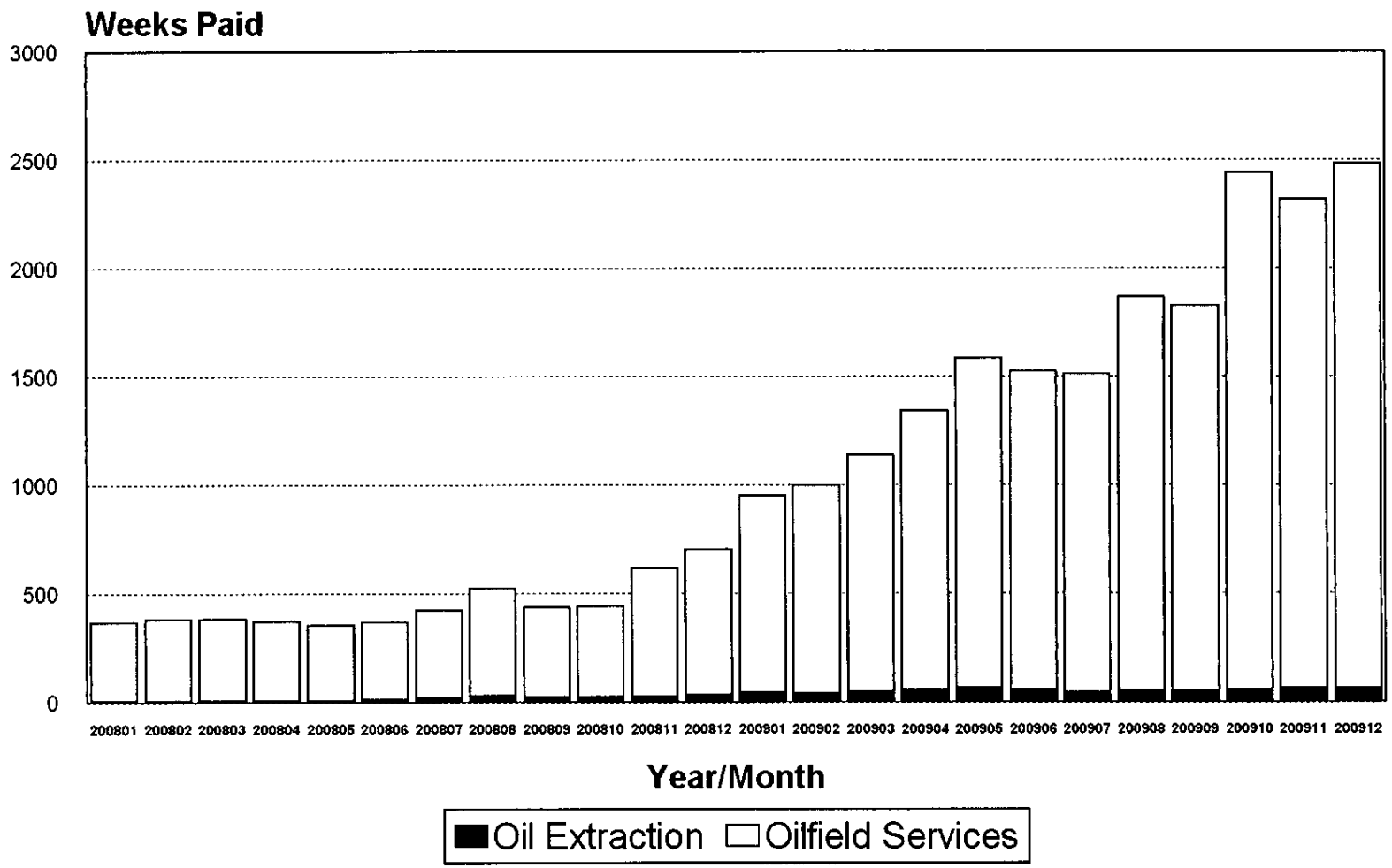
Sector Name	2003	2004	2005	2006	2007	2008	2009
All Oil and Gas Industry related employment	**2,827**	**1,732**	**1,199**	**906**	**1,084**	**1,362**	**2,844**
In-State Claimants	2,316	1,426	1,028	795	928	1,208	2,331
Inter-State Claimants	511	306	171	111	156	154	513
All Industries	**64,071**	**61,544**	**53,053**	**51,597**	**47,776**	**45,343**	**63,630**
In-State Claimants	53,084	51,045	44,194	43,156	39,999	38,189	52,371
Inter-State Claimants	10,987	10,499	8,859	8,441	7,777	7,154	11,259

Source: Alaska Department of Labor and Workforce Development, Research and Analysis Section.

UI Claimants are defined as a count of individuals that formerly worked for employers classified in the industry sector of note, who collected at least one (1) week of Unemployment Insurance durring the given year. This includes both In-state as well as Inter-state claimants, and no individual is counted twice within one year. All Industries totals may not equal the sum of individual industries as Unclassified claimants are not included in the Industry breakouts.

Alaska Unemployment Insurance Weeks Paid by Month
2008-2009

(Preliminary)



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STATE OF ALASKA
DEPARTMENT OF LABOR
AND WORKFORCE DEVELOPMENT

Beth Leschper
Communications Director
907.465.2700
cell: 907.723.1321
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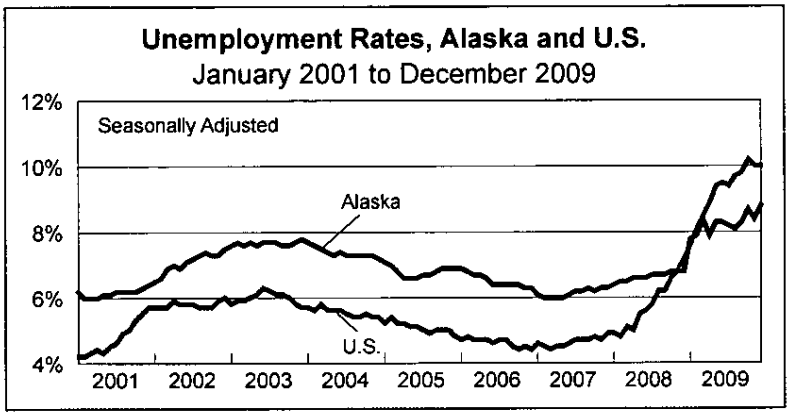
Press Release

COMMISSIONER'S OFFICE

January 22, 2010

No. 10-06

Unemployment rate at 8.8 percent in December



Alaska Nonfarm Payroll Employment[1]

	Preliminary 12/09	Revised 11/09	Revised 12/08	Changes from 11/09	Changes from 12/08
Total Nonfarm Employment[2]	306,500	310,500	309,200	-4,000	-2,700
Mining and Logging	15,100	15,200	15,700	-100	-600
Oil and Gas	12,900	12,800	13,100	100	-200
Construction	14,000	15,000	15,200	-1,000	-1,200
Manufacturing	6,600	9,500	7,200	-2,900	-600
Seafood Processing	3,300	5,000	3,400	-1,700	-100
Trade, Transportation and Utilities	61,900	61,700	63,200	200	-1,300
Retail Trade	35,500	35,500	36,500	0	-1,000
Information	6,800	6,800	7,100	0	-300
Financial Activities	14,200	14,300	14,600	-100	-400
Professional and Business Services	24,500	24,700	24,700	-200	-200
Educational[3] and Health Services	39,600	39,500	37,600	100	2,000
Health Care	28,700	28,600	27,300	100	1,400
Leisure and Hospitality	26,600	27,000	28,200	-400	-1,600
Accommodations	6,000	6,100	6,600	-100	-600
Food Svcs. and Drinking Places	16,800	17,000	17,800	-200	-1,000
Other Services	11,400	11,500	11,400	-100	0
Government[4]	85,800	85,300	84,300	500	1,500

[1] Not seasonally adjusted
[2] Excludes the self-employed, fishermen and other agricultural workers, and private household workers
[3] Private education only
[4] Includes public schools, the University of Alaska and federally recognized tribal entities

Unemployment Rates, Seasonally Adjusted

	12/09	11/09	12/08
Alaska	8.8%	8.4%	6.8%
U.S.	10.0%	10.0%	7.4%

Sources for graph and tables: Alaska Department of Labor and Workforce Development, Research and Analysis Section; and U.S. Bureau of Labor Statistics

Alaska's December seasonally adjusted unemployment rate was 8.8 percent. November's preliminary rate was revised down three-tenths of a percentage point to 8.4 percent.

The comparable national unemployment rate for December was 10.0 percent.

That marks the 12th month Alaska's rate has remained below the nation's. The last time that happened was in the early 1980s when the U.S. was in the midst of a very deep recession and Alaska was in the middle of an economic boom.

All the state's regions saw higher over-the-year unemployment rates in December. In Southeast, the rates were higher because of employment losses in leisure and hospitality, construction and retail. In the Gulf Coast, it was losses in the oil, and leisure and hospitality industries. In the Northern region, declines in the oil industry took their toll. In the Interior and Anchorage/Mat-Su regions, a long list of industries contributed to higher unemployment.

Another factor contributing to the rising jobless rate is the growth in the number of job seekers. Because Alaska's relative employment picture remains better than most of the nation's, fewer Alaskans are leaving the state looking for employment prospects elsewhere in the country and more job seekers are coming north looking for employment opportunities.

In December, over-the-month and over-the-year wage and salary employment were down. The seasonal losses in December are typical, led by seasonal losses in seafood processing, construction, and leisure and hospitality.

December marks the ninth month in a row of over-the-year employment losses. As 2009 progressed, the number of industries with employment losses grew. By December only educational and health services – more specifically health care and social assistance – and government remained positive.

Contact: Neal Fried, Economist (907) 269-4861
Research and Analysis' Web site: laborstats.alaska.gov

Labor Force by Borough and Census Area, Not Seasonally Adjusted[1]

	Civilian Labor Force			Unemployed					
				Number			Rate		
	12/09[P]	11/09	12/08	12/09[P]	11/09	12/08	12/09[P]	11/09	12/08
Alaska Statewide	**354,603**	**355,153**	**356,301**	**31,842**	**29,275**	**27,051**	**9.0**	**8.2**	**7.6**
Anchorage/Mat-Su Region	199,925	199,402	200,875	15,383	14,368	12,715	7.7	7.2	6.3
Municipality of Anchorage	157,710	157,531	158,621	10,978	10,407	9,012	7.0	6.6	5.7
Matanuska-Susitna Borough	42,215	41,871	42,254	4,405	3,961	3,703	10.4	9.5	8.8
Gulf Coast Region	**36,205**	**36,603**	**35,764**	**4,559**	**4,113**	**3,752**	**12.6**	**11.2**	**10.5**
Kenai Peninsula Borough	25,944	25,881	25,308	3,191	2,901	2,524	12.3	11.2	10.0
Kodiak Island Borough	5,939	6,217	5,802	831	713	711	14.0	11.5	12.3
Valdez-Cordova Census Area	4,322	4,505	4,654	537	499	517	12.4	11.1	11.1
Interior Region	**52,081**	**52,458**	**53,277**	**4,760**	**4,381**	**4,194**	**9.1**	**8.4**	**7.9**
Denali Borough	846	824	927	162	150	144	19.1	18.2	15.5
Fairbanks North Star Borough	44,727	44,850	45,830	3,718	3,439	3,255	8.3	7.7	7.1
Southeast Fairbanks Census Area	3,586	3,723	3,666	416	365	365	11.6	9.8	10.0
Yukon-Koyukuk Census Area	2,922	3,061	2,854	464	427	430	15.9	13.9	15.1
Northern Region	**12,666**	**12,591**	**12,370**	**1,144**	**1,096**	**923**	**9.0**	**8.7**	**7.5**
Nome Census Area	4,133	4,133	4,010	487	460	413	11.8	11.1	10.3
North Slope Borough	5,553	5,468	5,376	279	286	199	5.0	5.2	3.7
Northwest Arctic Borough	2,980	2,990	2,984	378	350	311	12.7	11.7	10.4
Southeast Region	**38,078**	**37,682**	**38,123**	**3,627**	**3,191**	**3,197**	**9.5**	**8.5**	**8.4**
Haines Borough	1,091	1,122	1,102	142	127	134	13.0	11.3	12.2
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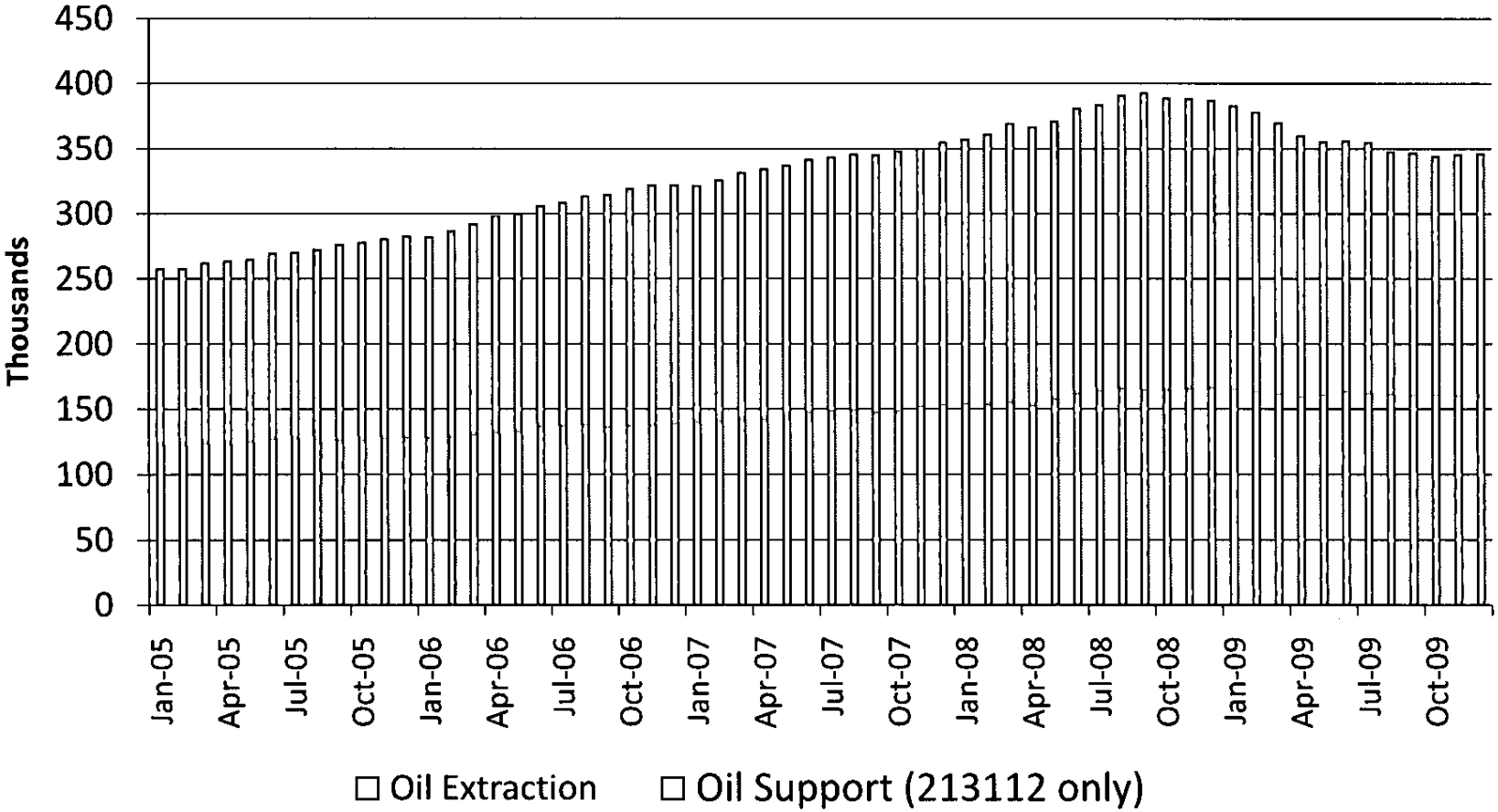
Monthly Oil Industry Employment US 2005-2009



Source: Alaska Department of Labor and Workforce Development, Research and Analysis Section and BLS.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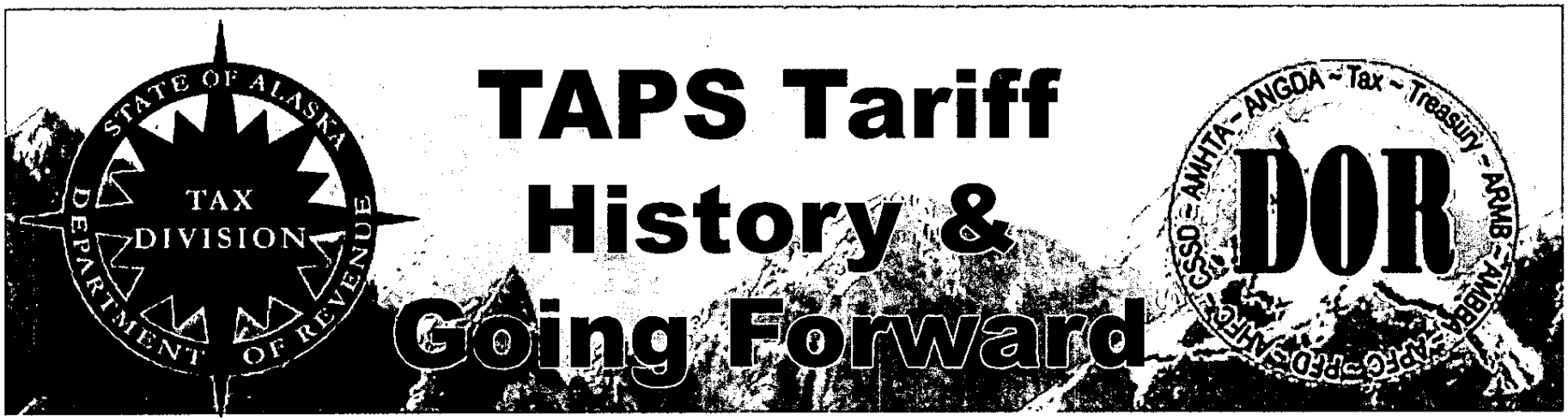


Presentation to the
Senate Finance Committee
February 16, 2010
Alaska Department of Revenue

Outline for Presentation

- **Netback Calculations**
- **Tariff History: 1978 to Present**
  - Challenges
  - Settlements
  - TSM
  - Opinion 502
- **Tariff Calculation & Drivers**
  - T Put
  - COS Components
- **Going Forward**

Production Tax and Royalty Calculation Based on Wellhead Value

- State oil and gas leases and production tax statutes calculate royalty and tax based on wellhead value
- Oil is primarily sold at west coast refineries
- Wellhead value is calculated through a net-back process that allows for deduction of transportation costs to point of sale

Transportation Costs

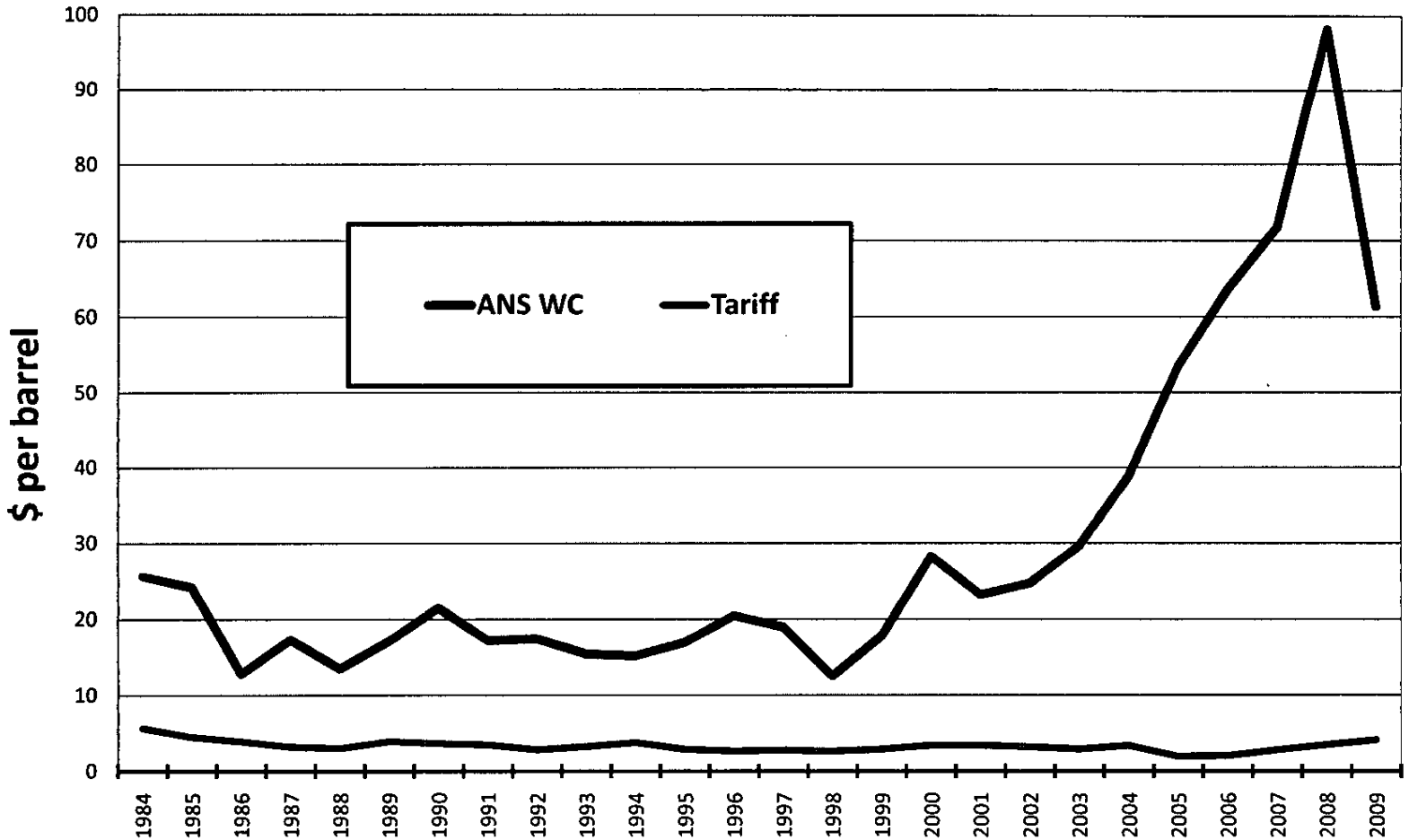
- Two primary transportation costs
  - pipeline tariffs
  - marine (tanker) costs
- Pipeline tariffs are set by state and federal regulators
- Intrastate rates set by Regulatory Commission of Alaska (RCA)
- Interstate rates set by Federal Energy Regulatory Commission (FERC)

ANS Netback Price

Estimated February 2010

West Coast Price	**$74.50**
Less	
Marine Costs	2.05
TAPS Tariff	4.10
Feeder Pipeline	.35
ANS Wellhead Price	**$68.00**

TAPS Tariff vs Crude Oil Price



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Initial TAPS Tariff

- TAPS began shipping oil in 1977
- Initial tariffs filed by TAPS Carriers charged over $6.00 per barrel
- Filed rates go into effect subject to refund until litigation completed

Initial TAPS Tariff Litigation

- State protested initial tariffs in 1977
  - FERC
  - APUC (RCA predecessor)
- In 1985 with no end to litigation in sight

  State and TAPS Carriers negotiated tariff settlement

TAPS Settlement Agreement (TSA)

- Formulaic method to calculate annual rates
- Annual true-up based on actual costs
- Settlement formula set rate ceiling
- State would not protest charged rate unless
  - ➢higher than those derived from the TSM methodology
  - ➢imprudent costs or otherwise inconsistent with the law

Other TSA Provisions

- Binds only State and TAPS Carriers
- Third party shippers free to challenge settlement rates anytime
- State could audit annual filings
- Could be terminated January 1, 2009
- Otherwise expire at the end of 2011

TAPS Intrastate Rate Protest

December 1996 Tesoro Alaska filed protest of the 1997 TAPS intrastate rates

2002 RCA issued Order 151 ruling

- 1997-2000 annual rates were not just and reasonable
- Established lower intrastate rate
- Ordered refunds

Interstate Rate Protests

- 2005 the State protested Carriers' interstate rates for unlawful discrimination
- Argued difference between the interstate and intrastate rates violated TSA and Interstate Commerce Act prohibitions
- Anadarko then protested 2005 rates as not "just and reasonable"
- State and Anadarko protested 2006, 2007 and 2008 TSA based annual rates when filed on same grounds

FERC Decision and Opinion 502

May 2007 the FERC ALJ issued an initial decision finding the TAPS 2005 and 2006 interstate rates were not just and reasonable

June 2008 FERC issued Opinion 502 affirming ALJ on all issues

- Ordered carriers to file new 2005 and 2006 rates based on current FERC regulatory formula (154-B methodology)
- Ordered refunds based on refiled rates
- Refunds for 2005-06 result in additional $600 million to State for adjusted production tax and royalty liabilities

2007– 2008 TAPS Rate Protests

- FERC ordered TAPS Carriers to recalculate and refile 2007 and 2008 annual rates based on Opinion 502 methodology
- Refunds for 2007-2008 result in additional $200 million to State for adjusted production tax and royalty liabilities

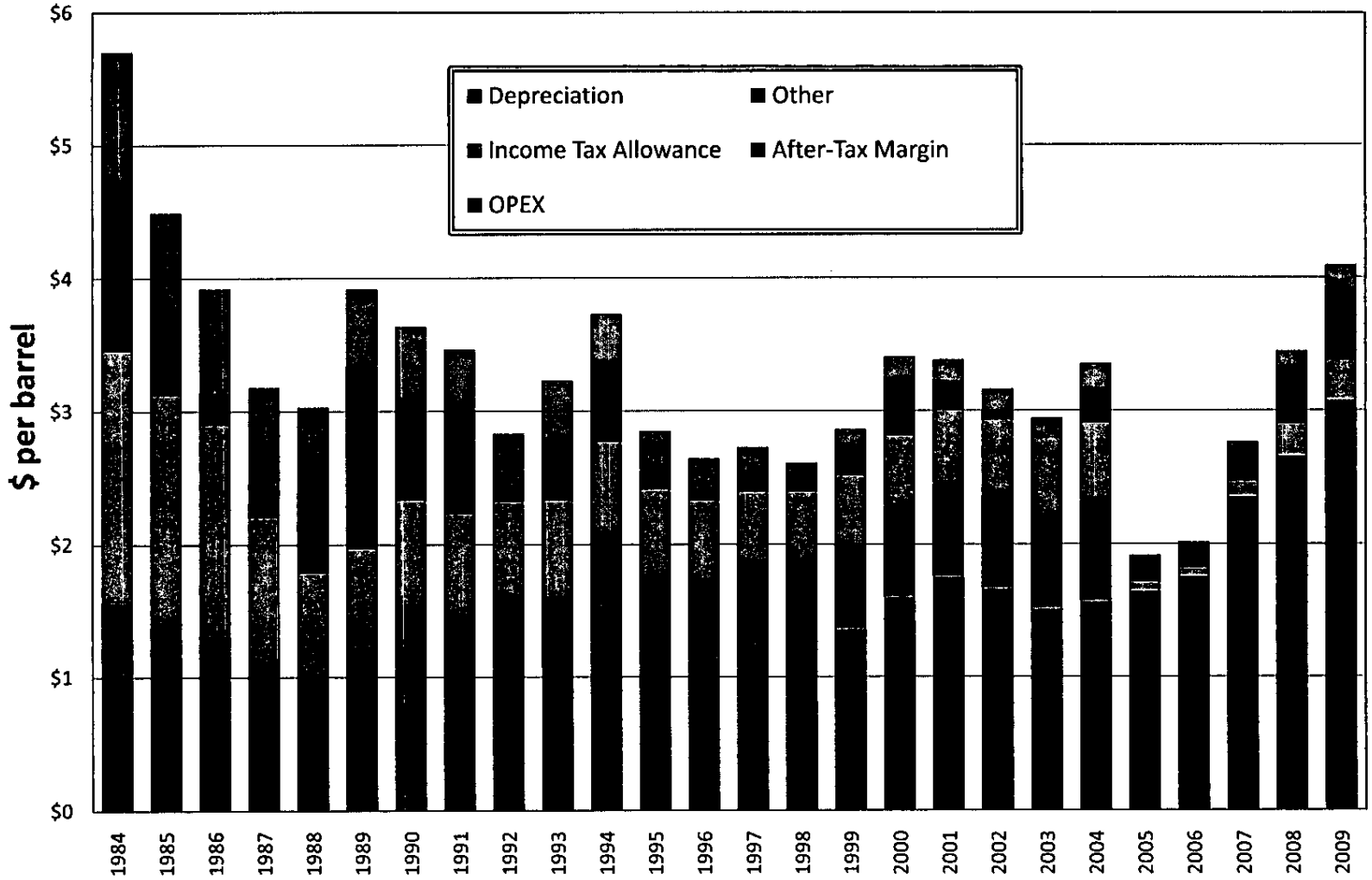
TAPS Settlement Terminated Effective January 1, 2009

- TSA allowed early termination before the December 31, 2011 expiration date
- State terminated settlement

Post-Settlement Rate Protests

- TAPS Carriers filed new intrastate rates at end of 2008 -early 2009
- TAPS Carriers filed new interstate rates in second half of 2009
- State and Anadarko protested those rate filings and new rate hearing is set at the FERC for October 2010

Components of TAPS Tariff



Cost of Service Components

Operating Expenses

+ Return **OF** Rate Base

+ Return **ON** Rate Base

+ AFUDC Amortization*

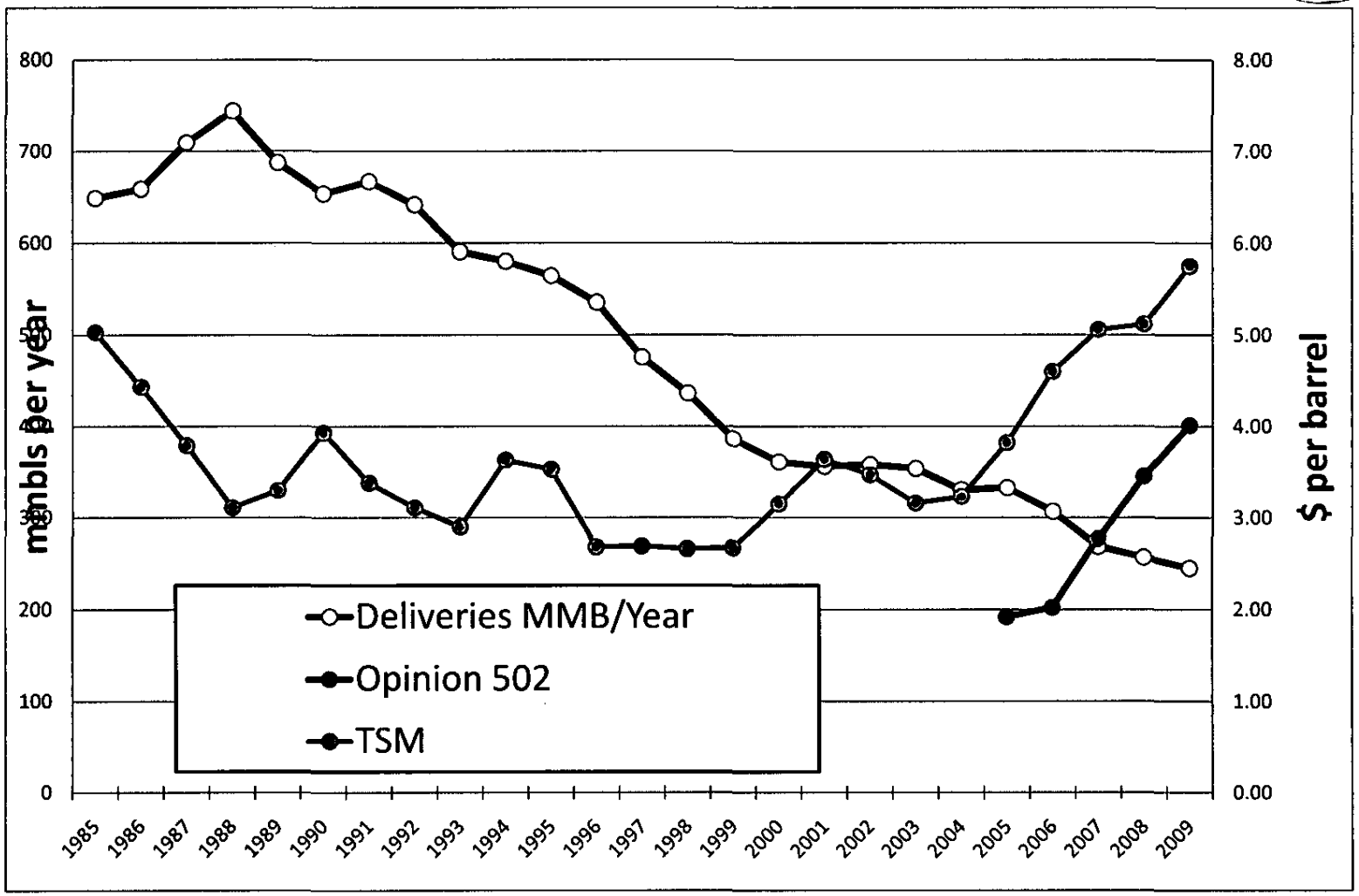
+ Income Tax Allowance

= COST OF SERVICE or

Total Revenue Requirement

*Allowance for Funds Used During Construction

TAPS Throughput and Tariff



Importance of Throughput

$$\text{Tariff} = \frac{\text{Total Revenue Requirement}}{\text{Throughput}}$$

Tariff increases if

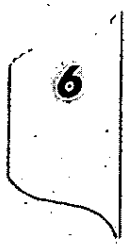
- Costs increase
- Throughput declines
- Combination of both

Throughput Required to Maintain 2010 Tariff Level

	Million Barrels Per Year			Thousands
	Forecast	Level Tariff	Diff	Per Day
2011	225	229	4	12
2012	226	231	5	13
2013	228	232	4	11
2014	228	234	6	16
2015	223	235	13	35
2016	217	237	20	54
2017	208	238	29	81
2018	197	239	42	115
2019	183	240	56	154

Tariff Going Forward

- Uniform rate
- Filed rate of $4.10
- No settlement agreement
- No access to data other than filings
- Stacked rate filings and protests
- FERC hearing October 2010
- Unresolved issues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PRODUCTION TAX LEASE EXPENDITURE REGULATIONS

Senate Finance Committee February 17, 2010

OVERVIEW

ACES passed 12/20/2007.

Regulatory Process governed by AS 44.62 – APA

DOR worked with the Department of Law in order to ensure the legality, constitutionality, and consistency with other regulations

All of our regulations are reviewed by the Department of Law as required. (AS 44.62.060)

Public Workshops

DOR shared outline of approach and then held "public workshops" to gain public input at early regulation design stage.

Significant changes were made as a result of comments received during workshops. If big changes on important issues, then additional workshops held.

Workshops were also teleconferenced.

APA – 30-Day Formal Notice

After Workshops, proposed regulation is put out for a minimum 30 day public comment under AS 44.62.190.

1) Published in a newspaper
2) furnished to every person who has filed for a request of proposed action ("Interested Parties")
3) Furnished to Dept. of Law
4) Provided to all incumbent State of Alaska legislators, committee chairs, and to the Legislative Affairs Agency.

APA – Notice of Proposed Action

The agency shall give each interested person an opportunity to present statements, arguments, or contention in writing, with or without opportunity to present them orally (AS 44.62.210(a))

Agency "shall consider all factual, substantive, and other relevant matter presented to it before adopting, amending, or repealing a regulation. (AS 44.62.210(b))

APA- Final Step

After considering public comment, regulation is either adopted, or put out for another public notice. Once regulation has been adopted:

- Regulation is put in final form
- Final review by Department of Law
- Submitted to Lt. Governor for review and signature
- Regulation effective 30 days after filing by Lieutenant Governor.

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Dec. 20, 2007 Workshop: Lease Expenditures & North Slope Gas Prevailing Value

1/2/2008 Production Tax Monthly Information Form

1/2/2008 Workshop Announcement, 1/14/2008

1/3/2008 Department of Revenue, Tax Division Notice of Public Workshop On Potential Changes to Oil and Gas Production Tax Regulations and Interim Monthly Reporting Form

Jan. 14, 2008 Workshop Tax Credits & Qualified Capital Expenditures under AS 43.55.023, AS 43.55.024 & AS 43.55.025, and interim form for reporting of monthly information

1/24/2008 Workshop announcement for 2-4-2008

1/30/2008 Draft Interim Form for Monthly Production Tax Information

1/30/2008 Request for Public Comments on Draft Interim Production Tax Information

1/31/2008 Discussion draft lease expenditures and overhead

Feb. 4, 2008 – Workshop – Transportation costs under AS 43.55.150, Lease Expenditures and Overhead under AS 43.55.165, and excluded costs from lease expenditures under AS 43.55.165(e).

2/5/2008 Comments on Discussion Draft Lease Expenditures extended to February 12

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- 2/14/2008 Request for Public Comment Draft Annual Report Form
- 2/28/2008 DOR Interim Annual Information Report Forms - Now Online
- 2/28/2008 Draft of proposed changes 15 AAC 55.520 - Reporting
- 2/28/2008 Public Notice of Proposed Oil & Gas Production Tax Regulations
- 2/29/2008 Draft Text of Proposed Oil & Gas Production Tax Regulations
- 2/29/2008 Public Workshop March 12, 2008 Interim Annual Reporting Form and Lease Expenditures
- 3/3/2008 Supplemental Public Notice Proposed Oil & Gas Tax Regulations 15 AAC 55.520
- 3/5/2008 Draft Interim Monthly Information Report
- 3/7/2008 Supplemental Notice for Workshop Scheduled March 12, 2008
- 3/12/2008 Agenda for 3-12-2008 Workshop
- March 12, 2008 – Workshop Annual Reporting Form and Lease Expenditures and overhead, Mid-year changes, Civil Penalties, lease expenditures for Cook Inlet and gas used in state, credit provisions for Cook Inlet gas and gas used in state, North Slope Gas Prevailing Value.

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- 3/18/2008 Draft lease expenditure and overhead regulations
- 3/18/2008 2007 Interim Annual Information Reporting Form
- 3/19/2008 2007 Revised Interim Annual Reporting Form - Second Half VERSION 2
- 3/19/2008 2007 Revised Interim Annual Reporting Form - First Half VERSION 2
- 3/21/2008 Correction in general instructions for DOR Interim Annual Information Reports 2007
- 3/24/2008 Advisory Bulletin 2008-01
- 3/24/2008 Request for Public Comment Draft Transportation Regulations
- 3/24/2008 A Proposed Model to Compute the Cost of Capital Allowance for Pipeline Facilities under 15 AAC 55.195(i)
- 3/27/2008 DOR Public Workshop April 8, 2008 Draft Transportation Regulations and Cost of Capital Model
- 3/28/2008 DOR Public Workshop April 8, 2008 Draft Transportation Regulations and Sample Capital Allowance for Pipelines
- 3/28/2008 Revised Draft Transportation Regulations
- April 8, 2008 – Workshop – Transportation and cost of capital allowance
- 4/8/2008 Comment Period Extended to 4/15/08 for Draft Transportation Regulations

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4/21/2008 Public Notice: Midyear Changes, North Slope PV, and Cook Inlet & Gas Allocations

4/21/2008 Proposed Regulations: Mid-year Changes, North Slope PV, and Cook Inlet & Gas Allocations

5/8/2008 Notice of Adopted Changes in the Regulations dealing with the Oil and Gas Production Tax and Required Monthly Filings

5/8/2008 Adopted Regulation 15 AAC 55.520

5/9/2008 DOR Public Workshop June 4, 2008 Draft Transportation Regulations V2 & Cost of Capital Model V2

5/9/2008 Draft Transportation Regulations Version 2

5/9/2008 Sample Cost of Capital Model for Pipelines Version 2

May 16, 2008 – Public Hearing – Prevailing Value, Mid-year changes, lease expenditures for Cook Inlet gas and gas used in state, and credits for Cook Inlet gas and gas used in state.

5/19/2008 DOR Monthly Information Report Notice

5/19/2008 DOR Monthly Information Reporting Form - Final

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June 4, 2008 – Workshop – Transportation and cost of capital

6/30/2008 Advisory Bulletin 2008-03, Taxability of Waste Oil Streams

8/5/2008 Public Notice: Regulation Changes Related to AS 43.55.025, Alternative Tax Credits for Oil & Gas Exploration

8/5/2008 Proposed Regulations Text: Changes to AS 43.55.025

Sept. 3, 2008 – Public Hearing – Alternative Tax Credits for Oil & Gas Exploration

9/9/2008 Lease Expenditure & Overhead Workshop 9/23/08 - draft proposed regulations – Text

9/9/2008 Lease Expenditure & Overhead Workshop, 9/23/08 – Notice

9/10/2008 Post-Filing Notice AS 43.55.173

9/19/2008 Lease Expenditure & Overhead Workshop RESCHEDULED from 9/23/08 to 10/7/08

9/19/2008 Proposed Mid-year and Conforming Changes Text, Public Hearing 10/09/2008

9/19/2008 Public Notice - Midyear & Conforming Changes Public Hearing 10/09/08

10/6/2008 Supplemental Topic October 7, 2008 Workshop, Adjustments to Lease Expenditures under AS 43.55.170

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Oct. 7, 2008 – Workshop – Lease expenditures and overhead, credits for qualified capital expenditures, and adjustments to lease expenditures under AS 43.55.170

Oct. 9, 2008 – Public Hearing – Mid-year and conforming changes, civil penalties, lease expenditures for Cook Inlet gas and gas used in state, and credits for Cook Inlet gas and gas used in state

11/28/2008 12/9/08 Workshop: Reimbursements Under AS 43.55.170 and Credits Under AS 43.55.023(a)&(b)

11/28/2008 12/9/08 Workshop Discussion Draft: Proposal for Reimbursements Under AS 43.55.170

11/28/2008 12/9/08 Workshop Discussion Draft: Proposed Credit Safeguard Regulation

12/5/2008 Input Requested on Proposed Forms for Monthly and Annual Reporting

12/5/2008 DOR Proposed Monthly Reporting Information to Calculate Gross Value at the Point of Production

12/5/2008 DOR Proposed Annual Information and Tax Calculation Form

Dec. 9, 2008 – Workshop – Reimbursements under AS 43.55.170, and tax credits under AS 43.55.023

12/22/2008 Comment Period Extended for AS 43.55.170 Reimbursements and Credit Safeguard Regulation for AS 43.55.023(a)&(b)

12/22/2008 Monthly Electronic Reporting: New Process & Format Workshops January 20 & 27, 2009

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Dec. 9, 2008 – Workshop – Reimbursements under AS 43.55.170, and tax credits under AS 43.55.023

12/22/2008 Comment Period Extended for AS 43.55.170 Reimbursements and Credit Safeguard Regulation for AS 43.55.023(a)&(b)

12/22/2008 Monthly Electronic Reporting: New Process & Format Workshops January 20 & 27, 2009

12/24/2008 Text of Proposed Draft Regulations for Public Notice: Lease Expenditures & Overhead

12/24/2008 Public Notice: Proposed Lease Expenditure & Overhead Regulations

1/13/2009 WORKSHOP CANCELLATION: January 20 & 27 Revised Electronic Submission Process and Format of Monthly Information Reporting Form

1/13/2009 Sample Cost of Capital Model for Pipelines - Version 3 1/27/09 Workshop

1/13/2009 Transportation Costs Workshop: Tuesday, January 27, 2009

1/14/2009 Transportation Workshop 1/27/09 Discussion Draft Proposed Regulations

1/16/2009 Supplemental Announcement Transportation Workshop

1/16/2009 Supplemental Topic Transportation Workshop Proposed Definition of "affiliated" AS 43.55.150(b)

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1/16/2009 SUPPLEMENTAL AND CORRECTED NOTICE: Lease Expenditures & Overhead Public Hearing Comment Period Extended from February 4 to February 23, 2009 and Corrected Call-in Number for Teleconference

Jan. 21, 2009 – Public Hearing – Lease Expenditures and overhead

1/26/2009 Agenda for January 27, 2009 Transportation Workshop

1/26/2009 Discussion Topic for 1/27/09 Transportation Workshop: Determining How to Apply Lower of Actual or Reasonable Costs

Jan. 27, 2009 – Workshop – Transportation – How to apply lower of actual or reasonable costs under AS 43.55.150

1/28/2009 Proposed Transportation Regulations: Example Section 181(g).xls

1/28/2009 Proposed Transportation Regulations: Example Section 195(m).xls

1/29/2009 How to Access Audio Recording for Lease Expenditure & Overhead January 21, 2009 Public Hearing

2/10/2009 Advisory Bulletin 2009-01, gas "used in the state"

2/26/2009 Reimbursements under AS 43.55.170 Proposed 15 AAC 55.280 Revised Draft

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2/27/2009 Workshop Announcement Reimbursements under AS 43.55.170 Proposed 15 AAC 55.280 Revised Draft 2/27/09

March 17, 2009 – Workshop – Reimbursements and adjustments to lease expenditures under AS 43.55.170

5/4/2009 Announcement Regarding Revised Economic Monthly Information Report

5/4/2009 Instructions for Economic Monthly Reporting Data Delivery Process

5/18/2009 Revision to Monthly Information Report Form.

5/20/2009 Notice Regarding Suspension of the Revised Economic Monthly Information Report posted May 4 and Second Revision posted May 14, 2009

6/9/2009 Supplemental Public Notice AS 43.55.025 Alternative Tax Credit Proposed Regulations

6/9/2009 Text of Proposed Regulations for AS 43.55.025 Alternative Tax Credits

June 23, 2009 – 2nd Public Hearing – Alternative Tax Credits under AS 43.55.025

7/17/2009 Workshop Announcement: Proposed 15 AAC 55.280, Reimbursements Under AS 43.55.170, July 28, 2009

7/17/2009 Workshop Draft: Proposed 15 AAC 55.280, Reimbursements Under AS 43.55.170

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July 28, 2009 – Workshop – Reimbursements and adjustments to lease expenditures under AS 43.55.170

7/30/2009 Summary of Changes, Proposed 15 AAC 55.280 as Discussed March 17 to July 28, 2009 Public Workshops

9/22/2009 Adopted Regulations Text for Mid-year and Conforming Changes

9/22/2009 Adoption Notice Mid-year and Conforming Regulation Changes

9/29/2009 Advisory Bulletin 2009-02, State Purchase of Transferable Tax Credit Certificates

10/16/2009 Public Notice Proposed Regulations 15 AAC 55.280 Adjustments to Lease Expenditures, 55.320 Transferable Tax Credit Certificates, and 55.810 and 55.811 Heating Value of Gas

10/16/2009 Text of Proposed Regulation 15 AAC 55.810 and 55.811 Heating Value of Gas

10/16/2009 Text of Proposed Regulation 15 AAC 55.320 Credit Safeguard

10/16/2009 Text of Proposed Regulation 15 AAC 55.280 Facility Sharing

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11/5/2009 Reporting Form Draft Sample Company Credit Forms (pdf)

11/5/2009 Reporting Form Draft Sample Company Test Data Set II Excel 2003 ver.xls

11/5/2009 Reporting Form Draft Tax Return Sample Company Nov 2 2009 Excel 2003 ver.xls

11/5/2009 Reporting Forms Workshop Wednesday November 25, 2009

11/9/2009 Reporting Form Draft Tax Return Sample Company November 2 2009.xlsx

11/9/2009 Reporting Form Draft Sample Company Test Data Set II.xlsx

Nov. 10, 2009 – Public Hearing – Reimbursements and adjustments to lease expenditures under AS 43.55.170; transferable tax credit certificates under AS 43.55.023, and Btu heating value of gas.

11/13/2009 Advisory Bulletin 2009-03 Third Party Purchasers of AS 43.55.023 Tax Credit Certificates

11/17/2009 Second Reporting Forms Workshop Wednesday, December 2, 2009

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11/30/2009 Adoption Notice for Alternative Tax Credits

11/30/2009 Adopted Regulations for Alternative Tax Credits

12/17/2009 2009 Tax Summary Form in Excel

12/17/2009 Instructions for 2009 Tax Summary Form

12/17/2009 Delayed Implementation Proposed Reporting Form

1/27/2010 Public Notice: Proposed Regulation Changes Location Differential 15 AAC 55.171

1/27/2010 Proposed Language Location Differential Under 15 AAC 55.171

1/29/2010 Forms Announcement

1/29/2010 Tax Return Sample Company Jan 28 2010 version "xlsx"

1/29/2010 Tax Return Sample Company Jan 28 2010 Excel 2003 version "xls"

2/2/2010 Adoption Notice Lease Expenditures and Overhead

2/2/2010 Adopted Regulations for Lease Expenditures and Overhead

What remains?

46 of the approximate 70 production tax regulations we anticipate writing or revising have been adopted and signed into law by the Lt. Governor. Of those remaining, 17 relate to transportation and AGIA issues, 4 relate to facility sharing and BTU heating value.

Public Hearing for facility sharing and Btu heating value has been held and the written comment period has also been closed. The department is currently evaluating comments received.

Transportation and AGIA related Regulations distributed for public comment February 9, 2010

Unplanned Production Interruption regulations – Second workshop to be scheduled this spring.

Statutory Directions on Allowable Costs

AS 43.55.165(a)(1)(B) provides that, "[a] producer's lease expenditures for a calendar year are costs that meet the following three requirements:

(i) The costs must be incurred upstream of the point of production of oil and gas
(ii) The costs must be ordinary and necessary costs of exploring for, developing, or producing, as applicable, oil or gas deposits; and
(iii) The costs must be direct costs of exploring for, developing, or producing, as applicable, oil or gas deposits"

Statutory Directions on Allowable Costs

AS 43.55.165(b) further delineates lease expenditures as including:

(i) Direct cost of an asset even if it is capitalized for accounting or IRS purposes

(ii) Payments of property, sales, use, motor fuel, and excise taxes

(iii) Activity where the costs incurred do not are not on or near the oil and gas lease

Statutory Directions on Allowable Costs

- AS 43.55.165(b)(3) and (i) authorize the department to use as guidance:

(1) Typical industry practices and standards under operating agreements in effect before December 5, 2005 among multiple owners;

(2) DNR standards used to determine allowable costs under net profit leases

(3) Incorporation of concepts, regulations and guidance issued under IRS Code 482 for income and deduction allocation among taxpayers.

Lease Expenditure Regulations

- 15 AAC 55.250 - provides standards for the types of activities and purposes for which costs will be allowed, other than overhead.

- 15 AAC 55.260 - defines the direct charges that will be allowed as lease expenditures for the activities and purposes described in 15 AAC 55.250.

Lease Expenditure Regulations (Cont.)

- Types of activities and purposes allowed under 15 AAC 55.250:
  - Exploration costs, including mobilization of a drilling rig, crew costs, drilling, processing & interpreting data, and completion, abandonment, or suspension costs
  - Development & production costs, including designing, constructing, operating, or maintaining an oil or gas production facility or equipment
  - Support activities, such as camps, roads, bridges and similar transportation, communications systems, medical, security, and emergency facilities.

Lease Expenditure Regulations (Cont.)

- Direct costs under 15 AAC 55.260 for activities described in 15 AAC 55.250:
  - On-site labor
  - Technical labor whether on-site or remote location
  - Third-party contractor costs
  - Stand-by costs for a drilling rig
  - Property taxes and payments in lieu-of
  - Regulatory and permitting costs
  - Transportation costs of fluids used for reservoir maintenance and recovery.

State Regulations vs. IRS Rules

We align with the IRS Code in several instances:

- The Department uses IRS Code 263(c) to determine whether a cost is a qualified capital expenditure under AS 43.55.023(l).
- "Ordinary and necessary" costs defined by IRS code 162
- Incorporation of concepts, regulations and guidance issued under IRS Code 482 for income and deduction allocation among taxpayers.

We are directed to disregard the IRS code rules in some instances:

- We allow the deduction of a direct cost of an asset even if it is capitalized for IRS purposes .

Comments from Industry

"[W]e applaud the iterative process the Department has followed in developing these regulations and others in which it has offered its preliminary thoughts up for public comment (including industry's and has then used that feedback to revise and improve its drafts, which it then offered for further public comment. This consultative or collaborative public process is both prudent and wise. But because this takes more time than rule-making by simple fiat, it is important to recognize the more difficult path the Department has chosen for developing the ACES regulations has resulted in improvements to the earliest drafts that justify the greater time and effort that have been required. There is an old quip about never having enough time to do something right, but always time to do it over. Here the Department has avoided falling into this quip, which is no small feat and deserves recognition. "

Marilyn Crockett, Executive Director, AOGA, November 19, 2009

Comments from Industry

"Without clear regulatory guidance from the Department, AS43.55.170 may be interpreted in a manner which artificially inflates the costs associated with facility sharing in the state; and acts as a disincentive to future third-party facility access agreements.

....

Thanks to this collaborative effort and the Department's hard work, the proposed regulation largely addresses the concerns Pioneer has expressed over the past year, and in doing so, removes barriers to future facility sharing opportunities in the state."

Patrick Foley, Manager, Pioneer Natural Resources Alaska November 19, 2009

Conclusion

Tax Division's Regulations Process has ensured maximum meaningful input from industry and public.

When final public comment period begins, involved parties have had opportunity to critique proposed regulations and Division has had opportunity to fully understand how the regulations will impact industry and been able to address ambiguity and problems.

Industry input and dialogue with the Department has never been greater than in the implementation of the AS 43.55 regulations.