ALASKA LEGISLATURE COMMITTEE FILES 2007-2008 SRES 12707

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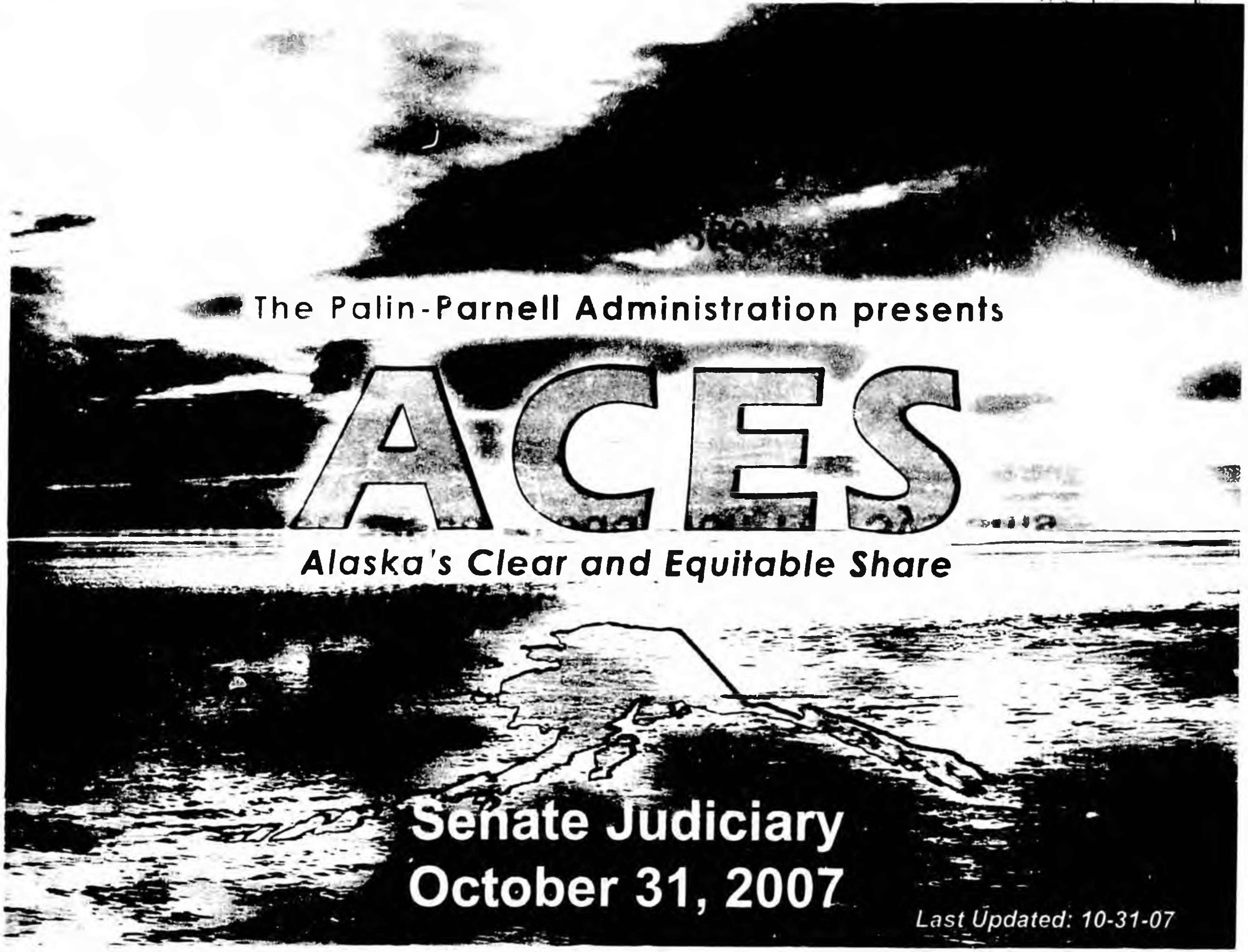
ADMIN.


The Palin-Parnell Administration presents
ACES
Alaska's Clear and Equitable Share
Senate Judiciary
October 31, 2007
Last Updated: 10-31-07

ACES

Alaska's Clear and Equitable Share

Comparison of Gross Based and Net Based Production Tax Systems

Pat Galvin

October 31, 2007

Pro's and Con's of Gross Tax and Net Tax

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Gross Tax

- Pro's
  - More Transparent
  - Less Audit/Litigation Burden
  - Less risk to revenue projection
- Con's
  - Creates a "one size fits all" problem for varying project economics
  - Errors in assumptions can stifle investment
  - To protect project economics, may have to accept less revenue

Net Tax

- Pro's
  - Investment climate "self corrects" to adjust to changes in costs
  - Provides more attractive investment climate
- Con's
  - Less Transparency
  - Greater Audit/Litigation Burden
  - Errors in assumptions can reduce revenue

Balancing Act

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Revenue

Investment Climate

Transparency

Economic Flexibility

Incumbents

New Entrants

Revenue from "Legacy" Fields

Exploration & New Field Development

Audit Risk

Investment Challenge

Factors to Consider

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- "Audit Risk"
- Revenue to the State
- Investment Climate

"Audit Risk"

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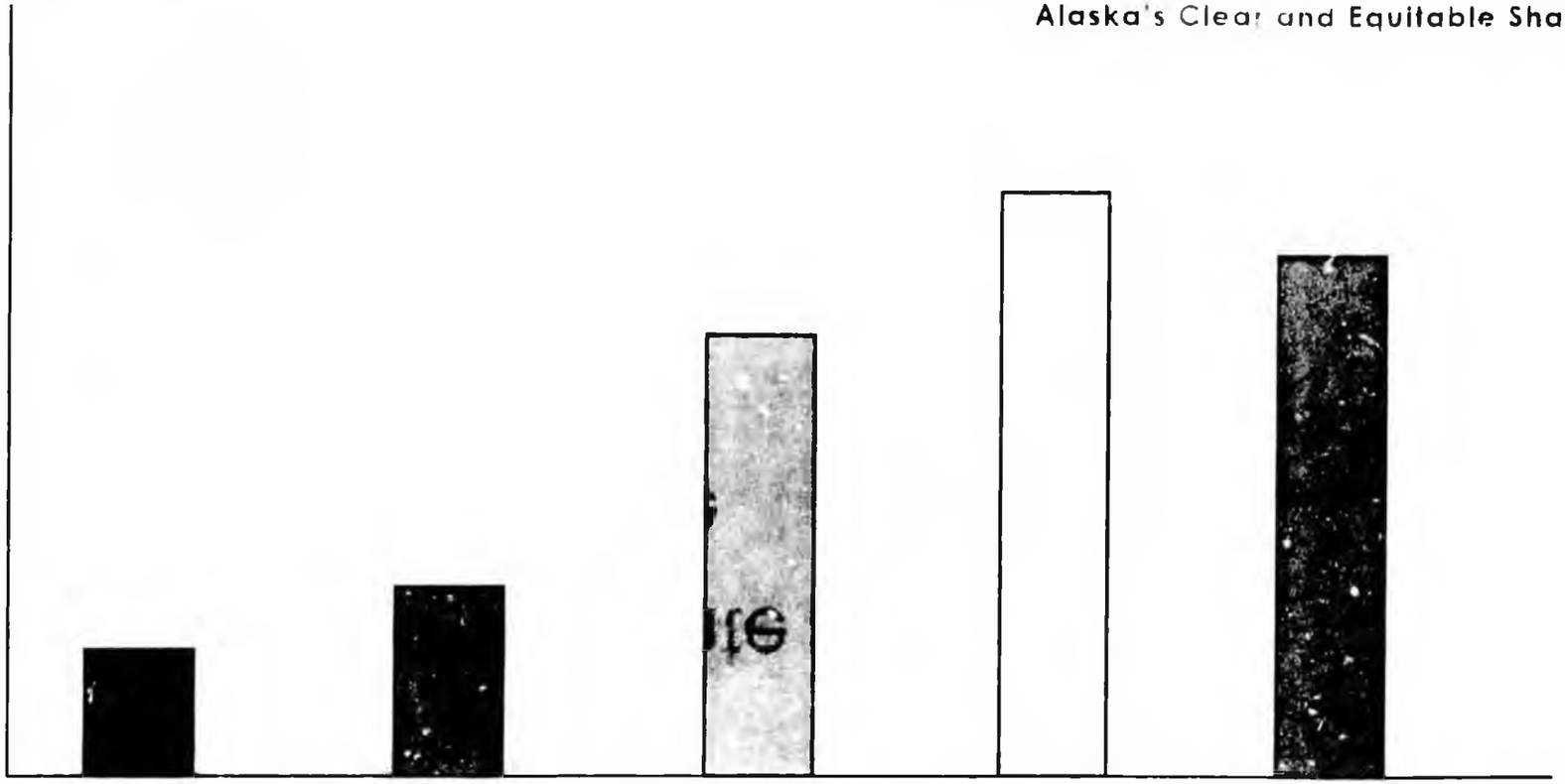

"Audit Risk"
How Do You Measure It?

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- Experience of Other Jurisdictions
  - No Record of Someone Going from Net to Gross due to frustration over "audit risk" — Double Auditors
- Similar Experiences In Alaska
  - Analogous to royalty disputes?
  - Net Profit Share Leases?
  - Distinction between contract and tax disputes
- "Trust Factor"
- Can You Mitigate the Risk?
  - Need the ACES Tools

Gross Tax
* Lower 48
much of Mineral
is privately owned
small resource base

PPT- more ~~audits~~

Galvin - Clearly the
Gov + myself were skeptical of "net"?

Revenue to the State

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- Revenue Model with field costs and production assumptions
- Can Calibrate Any Tax System to Hit a Revenue Target
- How Sensitive is the System to Changes in Assumptions?

Revenue vs. Investment

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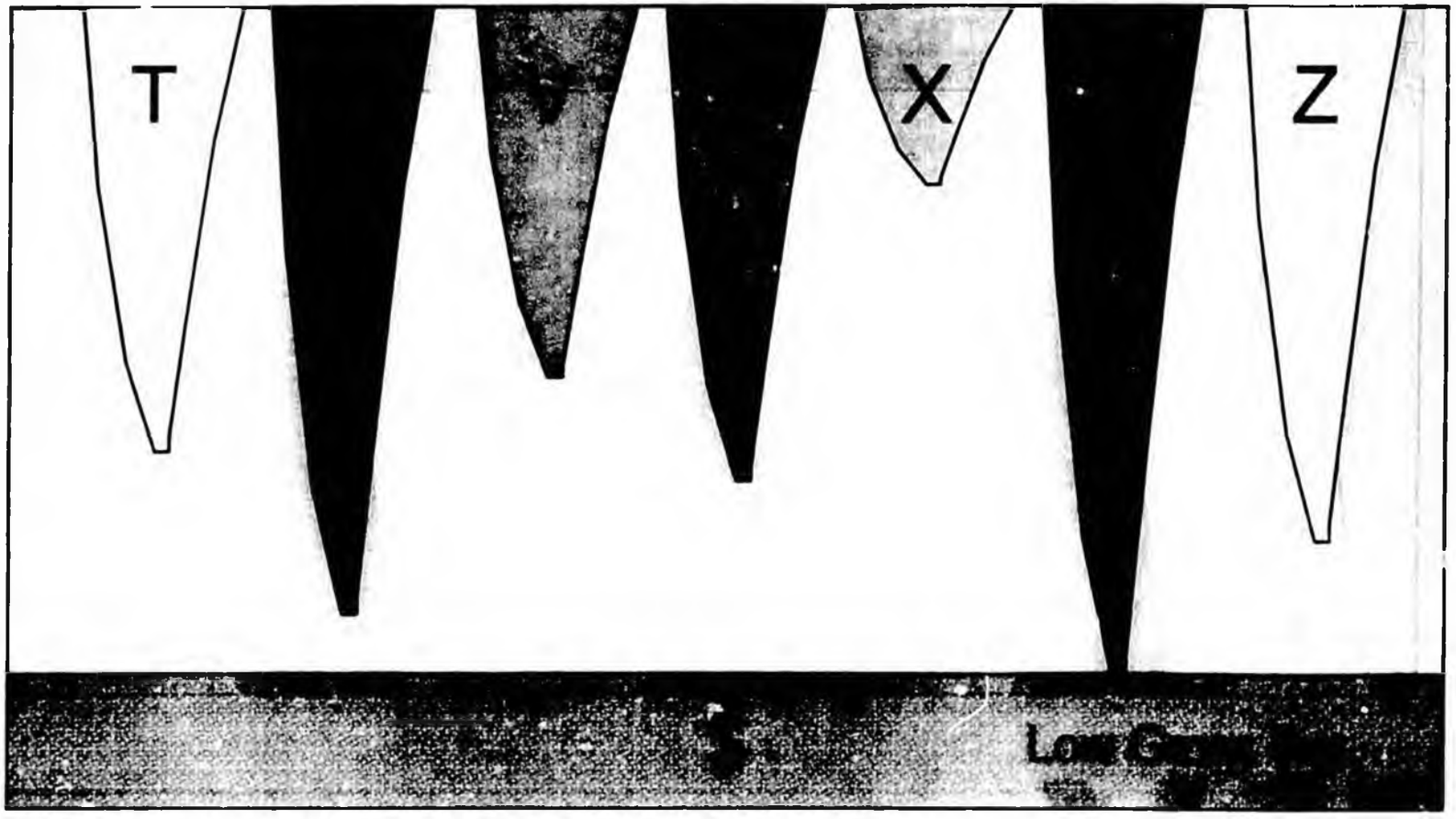

Revenue vs. Investment

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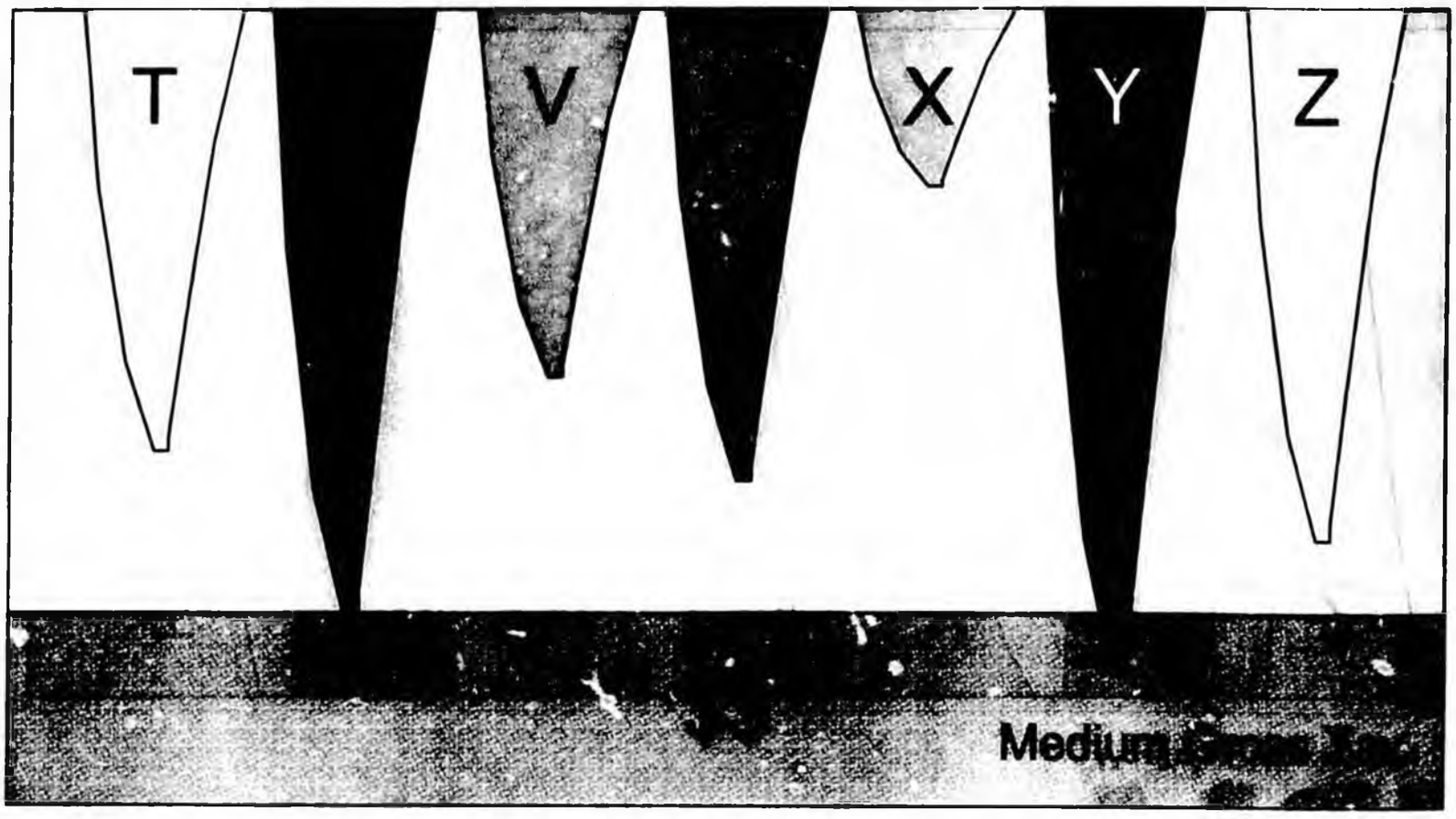

Revenue vs. Investment

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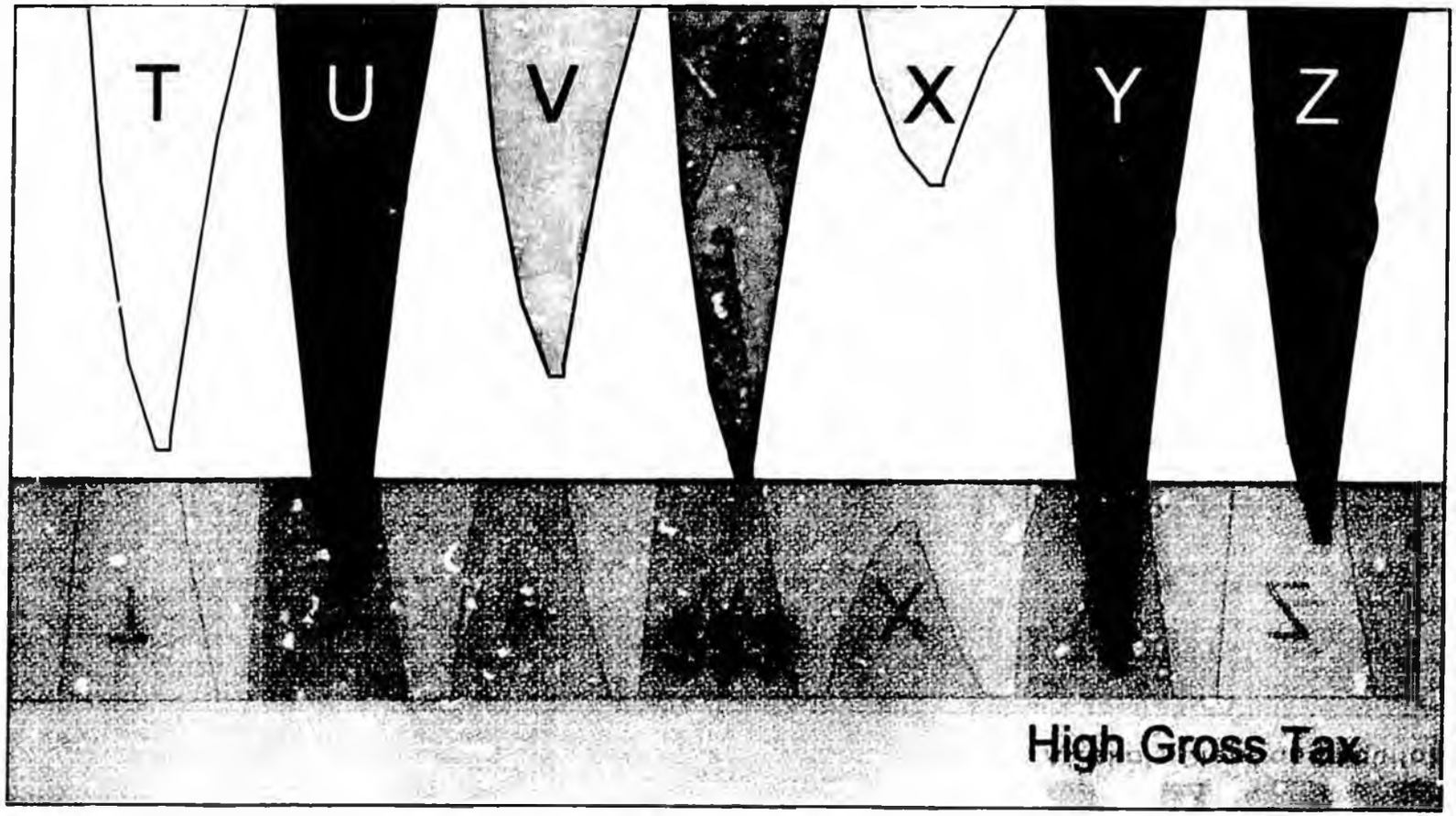

Revenue vs. Investment

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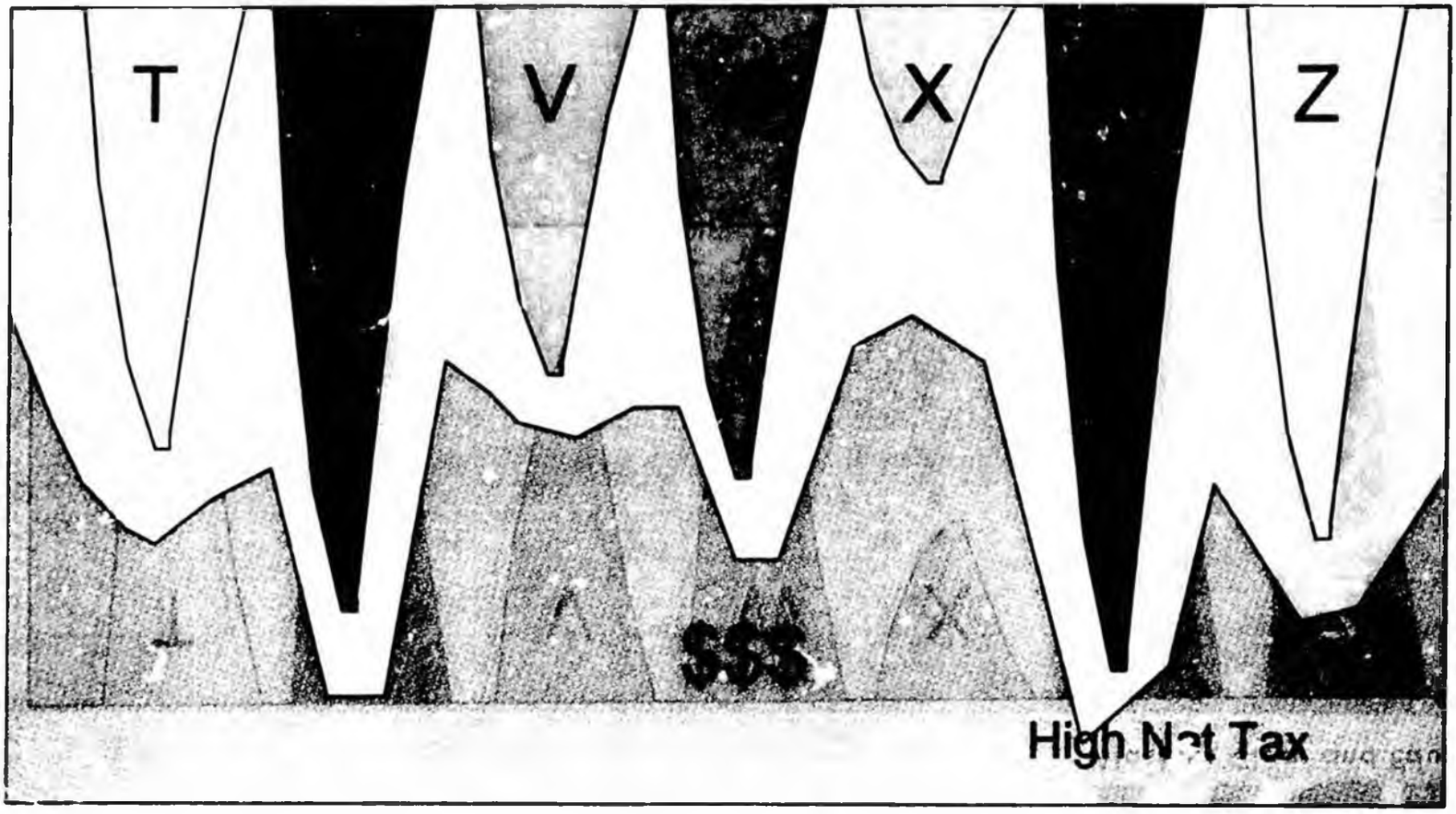

Investment Climate - Tests

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- New Fields (7 Field Models)
  - Actual project data - costs, production profile
  - NPV, IRR, Profitability Index at prices $30 to $100, and discount rates of 10% and 15%
  - Sensitivity Analysis to changes in cost assumptions
- "Legacy" Fields
  - Reinvestment Option analysis 3%, 6%, and 15% decline scenarios

Legacy v (TTF) Others

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New Field Tax Analysis - NPV Impact

Scenario	Rate		Progressivity		Capital	Industry NPV @ 10% at $40/bbl real ANS WC (mm$)						
	Mature Fields	Other Fields	Trigger	Rate	Investment Credit	Field A	Field B	Field C	Field D	Field E	Field F	Field G
ACES - 10% Floor	25.0%	25.0%	$30	0.0020	20%	10	60	40	40	(500)	210	1,000
ACES - NO Floor	25.0%	25.0%	$30	0.0020	20%	120	60	40	40	(300)	210	1,000
PPT Status Quo	22.5%	22.5%	$40	0.0025	20%	180	50	60	10	(200)	220	1,100
High Net Tax	35.0%	22.5%	$30	0.0030	20%	150	50	50	0	(200)	140	1,100

Scenario	Rate	Other Incentives	Progressivity		Capital	Industry NPV @ 10% at $40/bbl real ANS WC (mm$)						
	(All Fields)		Trigger	Rate	Investment Credit	Field A	Field B	Field C	Field D	Field E	Field F	Field J
Low Rate - No Credits	13%		$40	0.0020	None	(30)	(40)	(30)	(500)	(600)	80	700
Medium rate	16%		$40	0.0020	20%	30	0	0	(300)	(500)	130	800
Former Tax no ELF	16%		NA	NA	none	(40)	(50)	(30)	(400)	(600)	80	800
High Rate Flat Tax	19%		NA	NA	20%	20	(10)	0	(300)	(500)	130	900
Sliding Scale	Tax Table	5 Yr Holiday	NA	NA	20%	130	40	40	20	(400)	180	1,100

Legacy Field Scenarios

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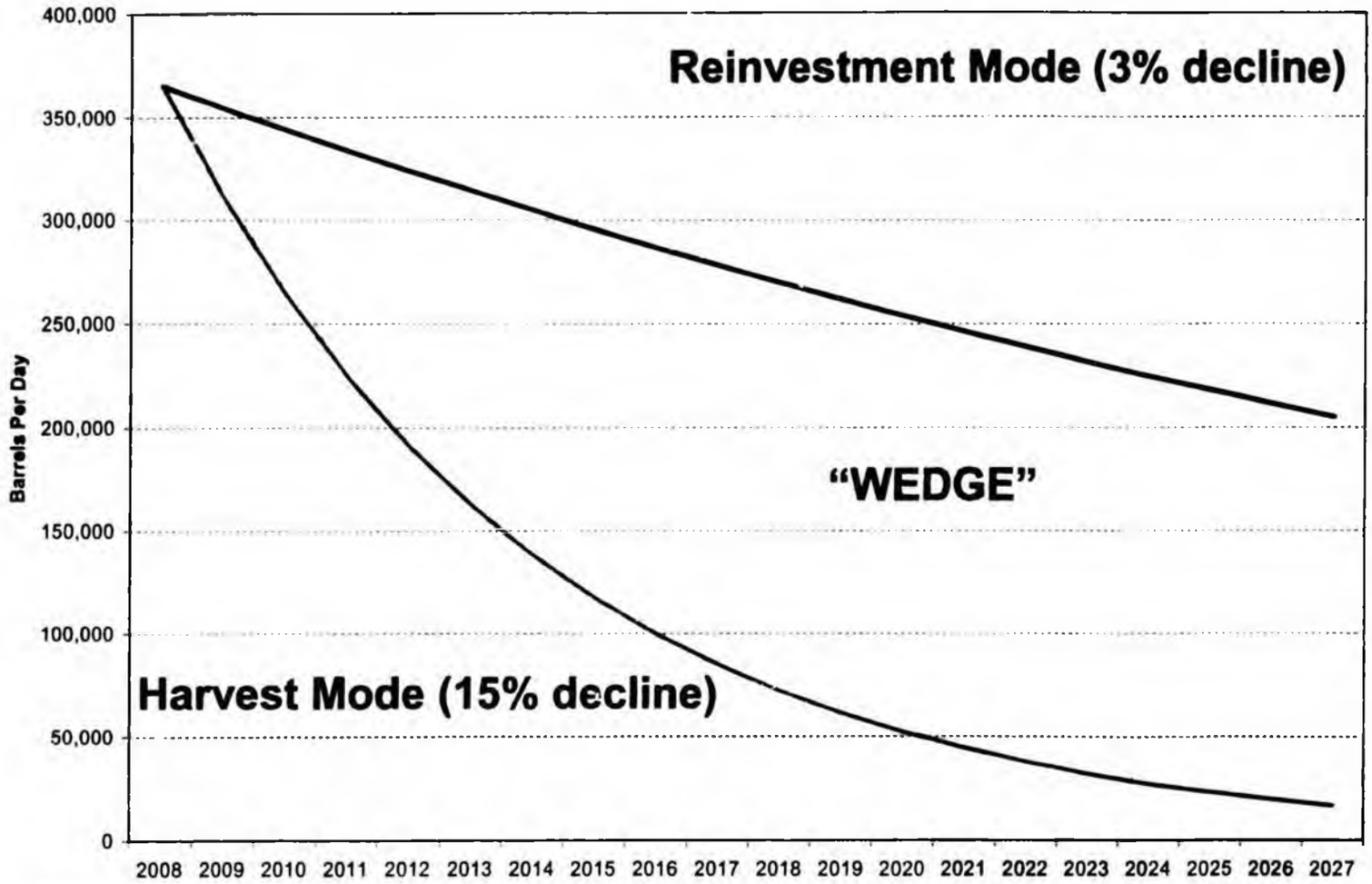

Legacy Field Reinvestment Comparison @ $40

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	Sustain Production Mode	Harvest Mode	Difference	
Decline Rate	3% per year	15% per year		
Oil Produced (mm Barrels)	2026	854	1172	
	NPV10 ($M)	**NPV10 ($M)**	**NPV Difference ($M)**	**Implied Investment Decision**
Net Cases:				
ACES	8235	6893	1342	Reinvest
PPT(SQ)	9176	7133	2042	Reinvest
35% tax rate	8022	6130	1892	Reinvest
Gross Cases:				
13% + no credits	6860	7207	(348)	DO NOT Reinvest
16% + no credit	6248	6889	(641)	DO NOT Reinvest
16% + 20% credit	7180	7027	152	DO NOT Reinvest
19% + no credit + no progressivity	6246	6706	(460)	DO NOT Reinvest

Assumes: 20 year horizon, OPEX+CAPEX=$5/BOE for Harvest, $15/BOE for Reinvestment. All cases assume progressivity unless noted.

Investment Climate Summary

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- Industry is more comfortable investing in a state that taxes based on net profits
- Net tax "self-adjusts" to changes in costs
- Heavy oil development is a challenge under a gross tax system
- Errors in cost assumptions under a gross tax can hamper investment climate

Balancing Act

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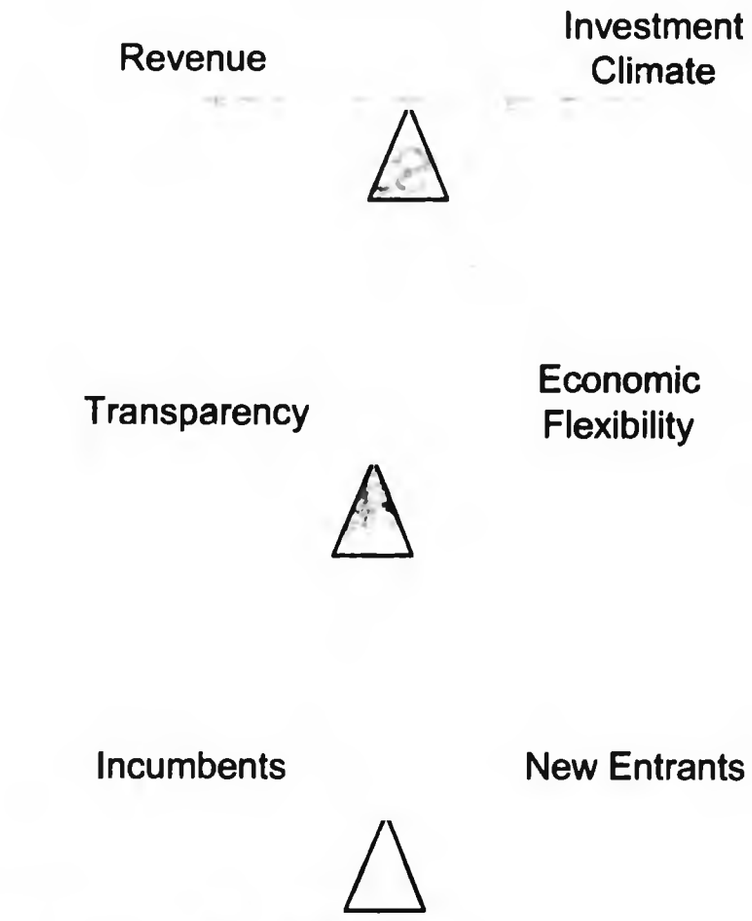

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REVENUE

Attached is response to Senate Resources Chairman, Sen. Huggins request for an illustration of ALL sources of revenue/income from the oil industry in Alaska, by category, showing actuals for years '05,'06,'07 and projected for 2008.

From DOR 10/23/07

Title: **FY2005 to FY 2008 Petroleum Revenue**

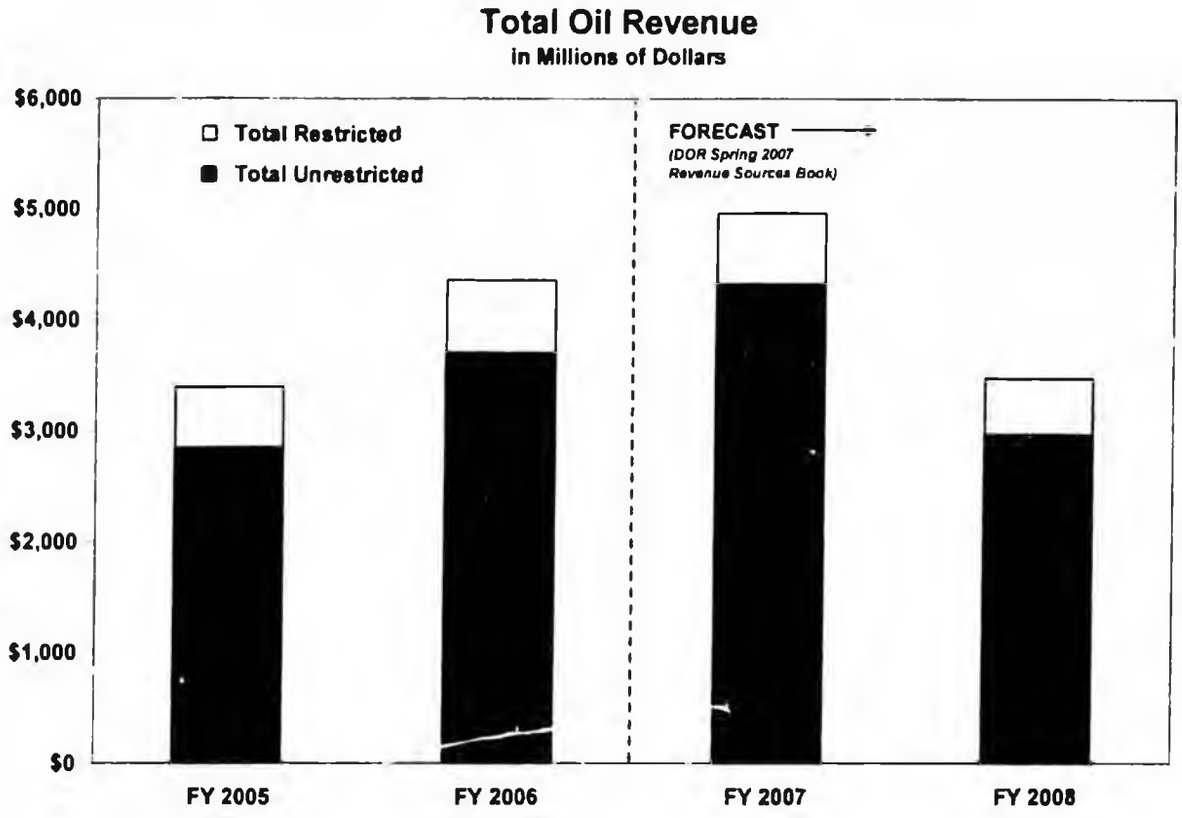
Data Sources: Alaska Department of Revenue, Tax Division
FY 2005 & FY 2006 from DOR historical database
FY 2007 Preliminary estimates
FY 2008 forecast from the Spring 2007 *Revenue Sources Book*

Prepared by: Jennifer Duval, Economist
jennifer.duval@alaska.gov

Date: October 23, 2007

Purpose: Request by Senator Huggins

Notes: Dollar amounts are millions of nominal dollars



Historical and Forecast Oil Revenues FY 2005 - FY 2008

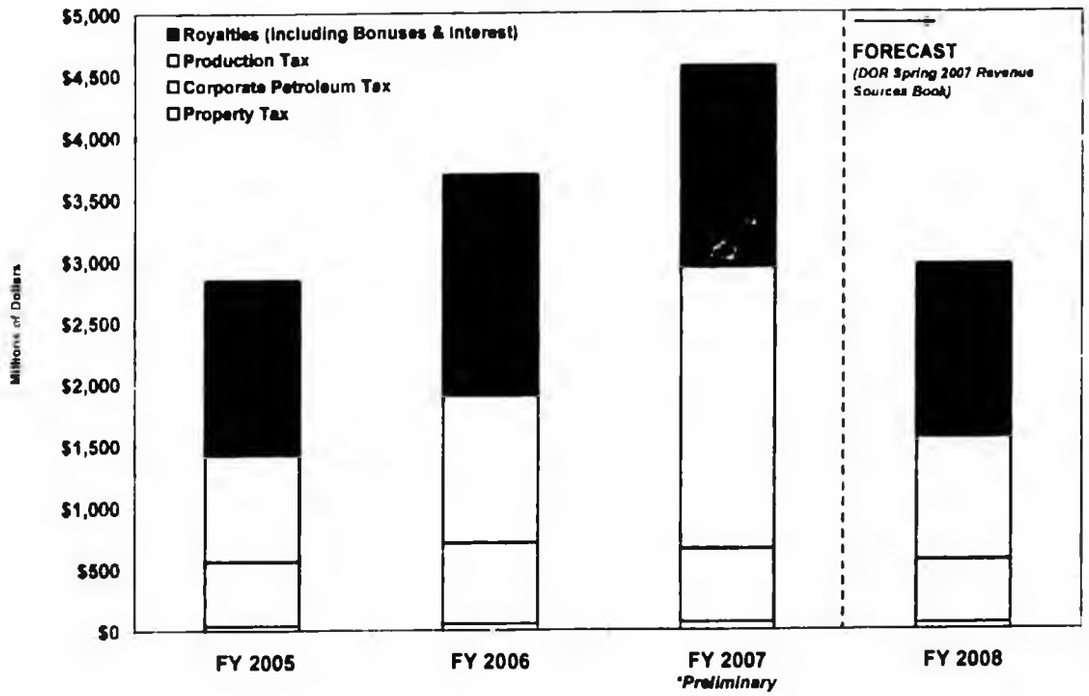
Source: DOR Spring 2007 Revenue Sources Book

in Millions of Dollars	ACTUAL FY 2005	ACTUAL FY 2006	PRELIM ACTUAL FY 2007 (10/22/07)	SPR 07 FORECAST FY 2008
Unrestricted				
Property Tax	42.5	54.5	65.6	53.2
Corporate Petroleum Tax	524.0	661.1	594.4	512.1
Oil & Gas Production	854.9	1,191.7	2,282.2	983.1
Oil & Gas Hazardous Release	8.3	7.8	10.1	12.3
Production Tax	863.2	1199.5	2,292.3	995.4
Mineral Bonuses & Rents	17.4	11.6	22.2	14.8
Oil and Gas Royalties	1401.1	1772.2	1,583.8	1,390.3
Interest	1.4	0.3	7.0	1.4
Royalties (including Bonuses & Interest)	1419.9	1784.1	1,613.0	1406.4
Total Unrestricted	**2,849.6**	**3,699.2**	**4,565.3**	**2967.10**
Year-over-Year change	795.5	849.6	866.1	-1,598.2
Year-over-Year % change	38.7%	29.8%	23.4%	-35.0%
Restricted				
Oil Royalties, Bonuses & Rents to Permanent Fund	476.9	599.5	535.0	471.5
Oil Royalties, Bonuses & Rents to School Fund	9.6	12	10.6	9.4
Royalties to Permanent Fund & School Fund + Bonuses & Interest	486.5	611.5	545.7	480.9
Settlements to CBRF	27.4	43.7	113.6	20
NPR-A Royalties, Rents & Bonuses	31.6	4.5	12.8	7.6
Total Restricted	**545.5**	**659.7**	**672.1**	**508.5**
Total Oil	**3,395.1**	**4,358.9**	**5,237.4**	**3,475.6**

Percent of Total Oil	FY 2005	FY 2006	FY 2007	FY 2008
Property Tax	1.3%	1.3%	1.3%	1.5%
Corporate Petroleum Tax	15.4%	15.2%	11.3%	14.7%
Oil & Gas Production	25.2%	27.3%	43.6%	28.3%
Oil & Gas Hazardous Release	0.2%	0.2%	0.2%	0.4%
Production Tax	25.4%	27.5%	43.8%	28.6%
Mineral Bonuses & Rents	0.5%	0.3%	0.4%	0.4%
Oil and Gas Royalties	41.3%	40.7%	30.2%	40.0%
Interest	0.0%	0.0%	0.1%	0.0%
Royalties (including Bonuses & Interest)	41.8%	40.9%	30.8%	40.5%
Total Unrestricted	**83.9%**	**84.9%**	**87.2%**	**85.4%**
Restricted				
Oil Royalties, Bonuses & Rents to Permanent Fund	14.0%	13.8%	10.2%	13.6%
Oil Royalties, Bonuses & Rents to School Fund	0.3%	0.3%	0.2%	0.3%
Royalties to Permanent Fund & School Fund + Bonuses & Interest	14.3%	14.0%	10.4%	13.8%
Settlements to CBRF	0.8%	1.0%	2.2%	0.6%
NPR-A Royalties, Rents & Bonuses	0.9%	0.1%	0.2%	0.2%
Total Restricted	**16.1%**	**15.1%**	**12.8%**	**14.6%**
Total Oil	**100%**	**100%**	**100%**	**100%**

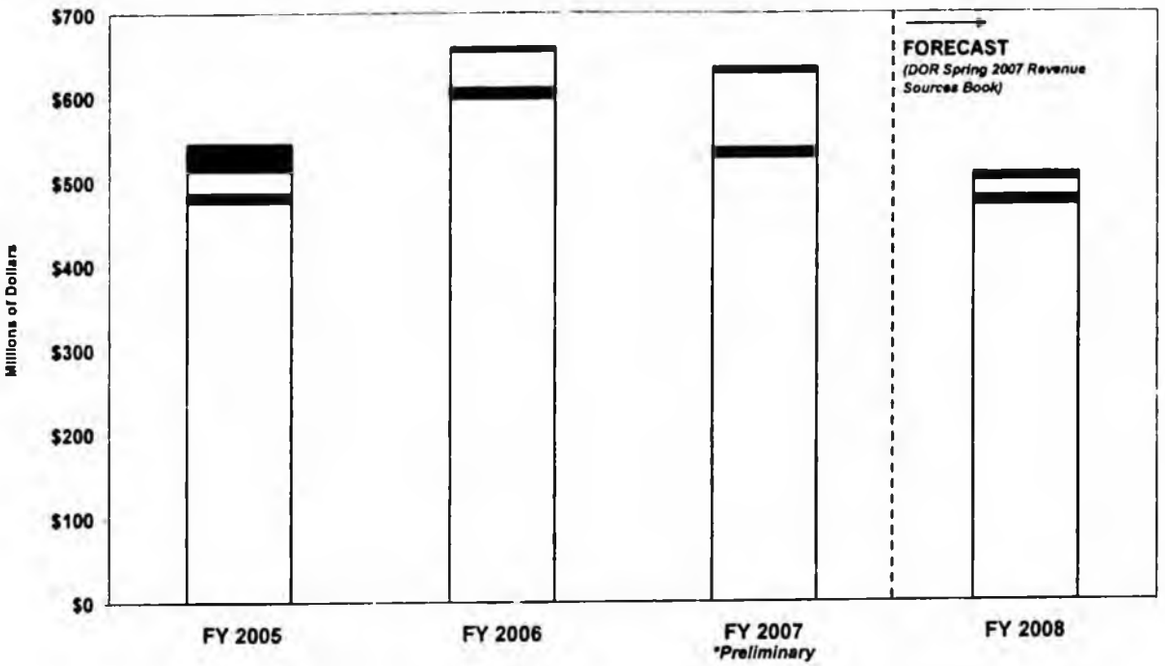
Unrestricted Oil Revenue by Category

FY 2005 to FY 2008



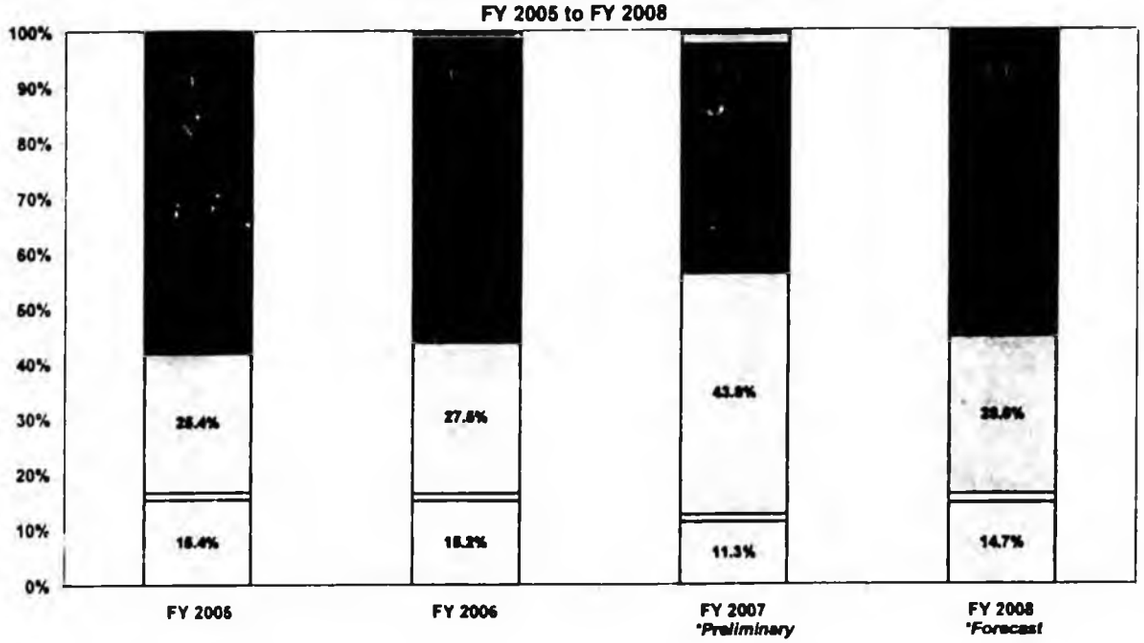
Restricted Oil Revenue

FY 2005 to FY 2008



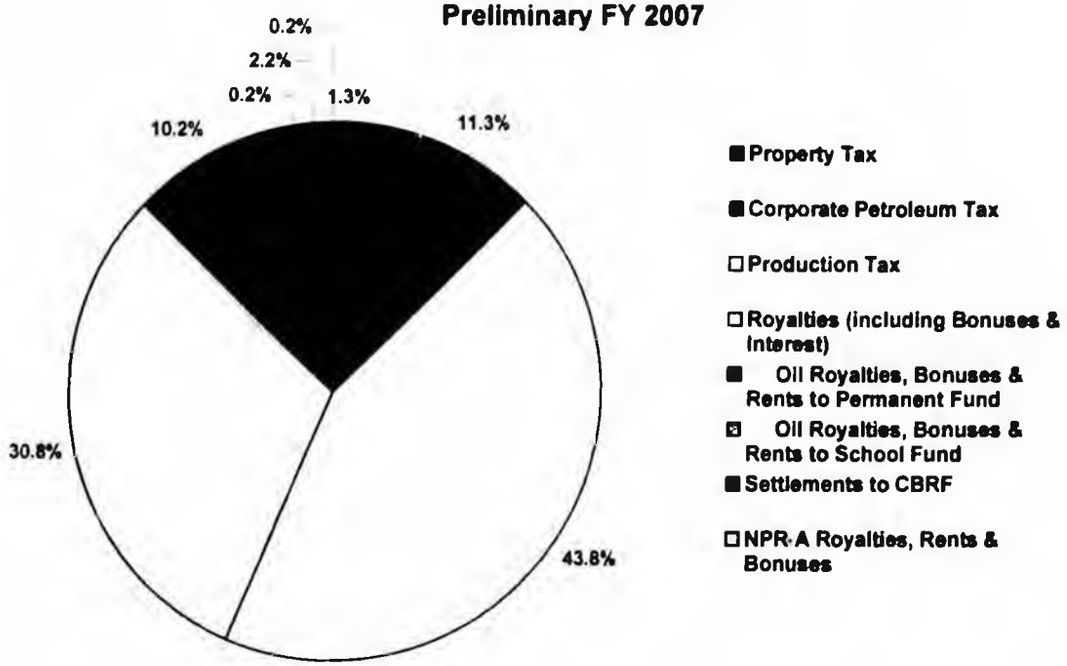
Percent Distribution of Total Oil Revenues by Year

FY 2005 to FY 2008

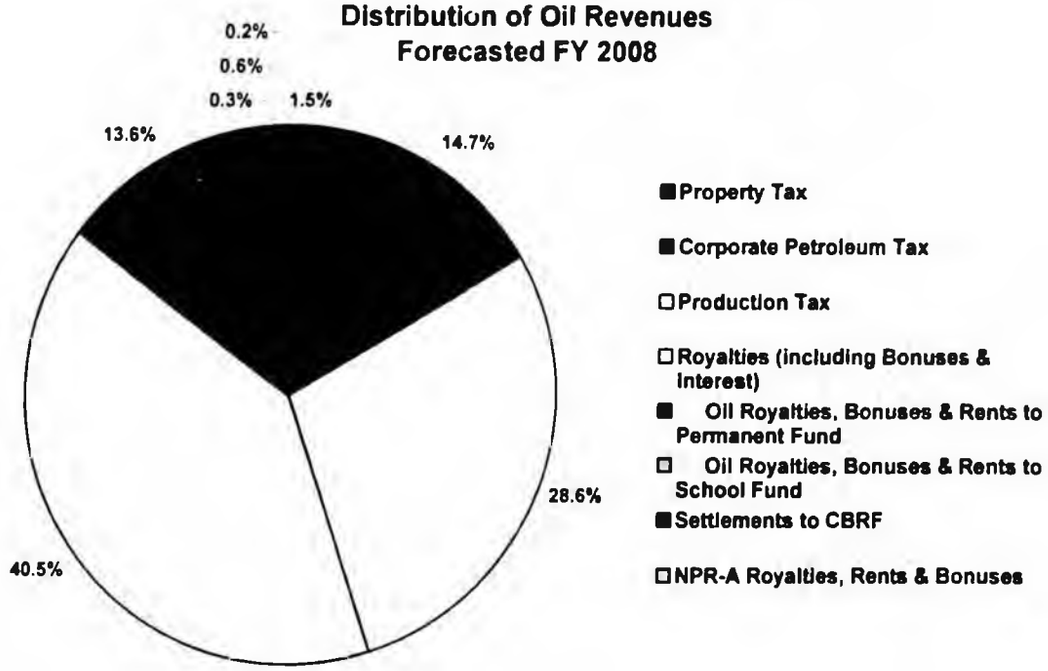


- Corporate Petroleum Tax
- Production Tax
- Oil Royalties, Bonuses & Rents to Permanent Fund
- Other Restricted
- Property Tax
- Royalties (including Bonuses & Interest)
- Settlements to CBRF

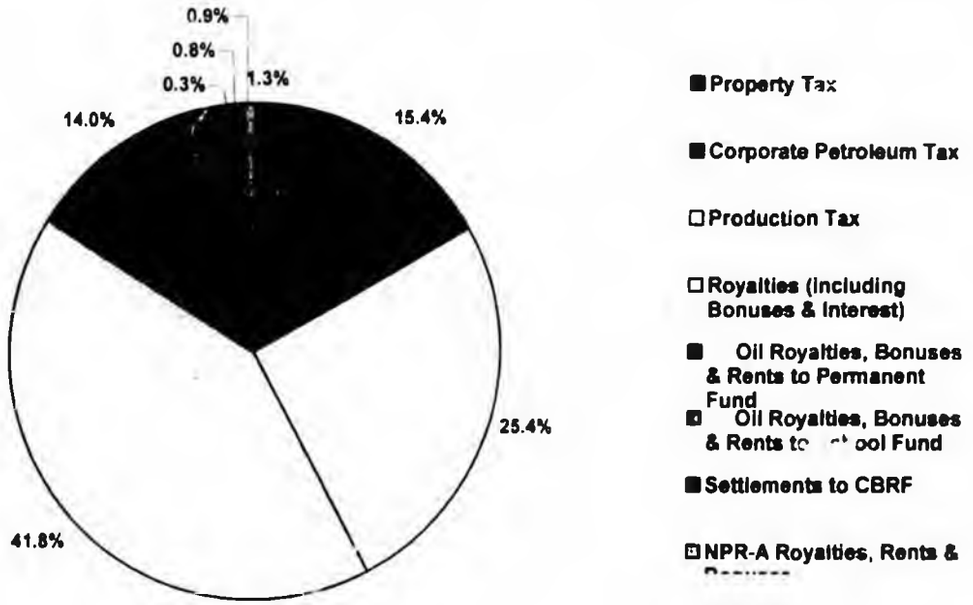
Distribution of Oil Revenues
Preliminary FY 2007



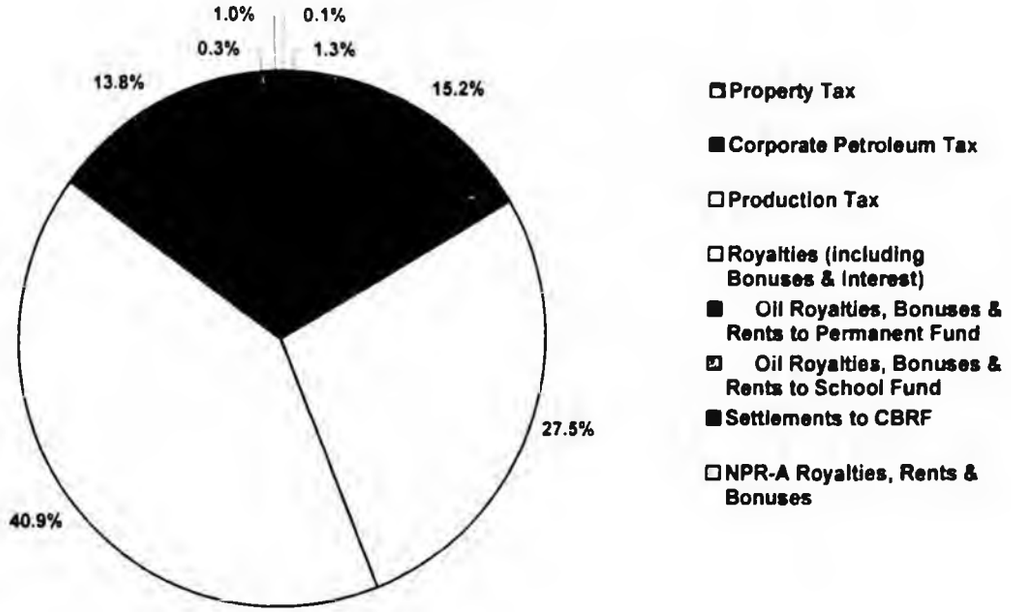
Distribution of Oil Revenues
Forecasted FY 2008



Distribution of Oil Reverues
FY 2005



Distribution of Oil Revenues
FY 2006



Why is the gas pipeline no longer economic?

Pedro van Meurs

October 27, 2007

Previous work

This judgment is based on a simple extrapolation of my earlier report on the economics of the pipeline prepared April 17, 2006. I will send the report separately for reference.

Following is a quote from the Executive Summary of this report regarding project economics under the proposed Stranded Gas Contract (in italics).

Why do we need a stranded gas contract?

The last three decades have proven that oil and gas price predictions are notoriously unreliable. In the late 70's an energy crisis was predicted with oil prices going up to very high levels. Then prices crashed in the mid 1980's. Only three years ago, the average long term oil price forecast was $ 25 per barrel, but they now exceed $ 60 per barrel. There is a significant possibility that oil and gas prices may be substantially lower again at some time in the future.

Therefore, a very large project with a very long lead time, requiring $ 20 billion or more, needs to be evaluated on the basis of a variety of possible scenarios of gas prices and costs.

In this study the following forecasts for the Chicago gas prices (2006 $) were used as representative of the currently prevailing conditions of major oil company views about the future:

- ***A low forecast of $ 3.50 per MMBtu (the "stress price")***
- ***An average forecast of $ 5.50 per MMBtu, and***
- ***A high forecast of $ 8.50 per MMBtu***

Currently, major oil companies use low price forecasts of $ 20 - $ 25 per WTI in order to test the economics of investment projects. This corresponds with the low forecast of $ 3.50 per MMBtu in Chicago. Therefore, extensive analysis was done on the Alaska Gas Project based on this stress price.

Also cost sensitivity was done based on 90% to 150% of capital and operating costs.

Furthermore, economics was done for a project ending in Alberta and in Chicago.

At this time it appears that a share of the gas can be delivered to Alberta without need for further pipelines based on on estimated take-away capacity of 2 Bcf/day in 2015. For the remaining gas, take-away capacity needs to be secured in order to deliver the gas to the Chicago area. This means the actual economics of the project will be somewhere between the Alberta and Chicago economics. Profitability indicators for a project ending in Chicago are lower than a project ending in Alberta. This is because of the much higher midstream investment that is required.

Seven profitability indicators were used to evaluate the Alaska Gas Project from the perspective of the investors:

- *The internal rate of return ("IRR")*
- *The net present value discounted at 10% ("NPV10")*
- *The profitability ratio discounted at 10% ("PFR10")*
- *The undiscounted net cash flow ("NCF")*
- *The NPV10 per barrel equivalent ("NPV10/BOE")*
- *The NPV10 over undiscounted capital expenditures ("NPV10/Capex"), and*
- *The NCF per barrel equivalent ("NCF/BOE")*

The importance of each of these profitability indicators is explained in more detail in the main report.

PFC Energy did a study on 60 competing oil and gas projects around the world requiring a capital investment of more than one billion dollars.

Based on this study each profitability indicator (in real 2006 $) was calibrated in such a manner that each target represented a value whereby 20% of the projects were less attractive and 80% of the projects were more attractive.

A project is unattractive when many of the indicators are below the targets or when some of the indicators are substantially below the targets. It should be noted that these targets only apply to the stress price of $ 3.50 per MMBtu in Chicago. At higher prices companies would select higher targets.

The following table illustrates the target values and whether the target values are being achieved. Values in "bold" mean that the target is not being achieved.

Minimum Criteria and the Alaska Gas Project in real 2006 $
At $ 3.50 stress price - no cost overruns

		Target	Status Quo Alberta	Status Quo Chicago	ASGFC Alberta	ASGFC Chicago	A+GTP Alberta	A+GTP Chicago
IRR	(%)	13%	**11.8%**	**10.6%**	13.5%	**11.9%**	14.0%	**12.2%**
NPV10	($ million)	2500	**1685**	**664**	2786	**2209**	3098	2520
PFR10	($/$)	1.15	1.18	**1.05**	1.35	1.19	1.39	1.21
NCF	($ billion)	20	50.8	62.5	50.2	60.5	50.7	61.0
NPV10/BOE	($/barrel eq)	0.33	**0.23**	**0.09**	0.38	**0.30**	0.42	0.34
NPV10/Capex	($/$)	0.12	**0.09**	**0.02**	0.17	**0.10**	0.19	0.11
NCF/BOE	($/barrel eq)	2.50	6.90	8.49	6.83	8.22	6.90	8.29

The table illustrates how under the Status Quo option and the low price of $ 3.50 per MMBtu the Alaska Gas Project would not be viable. Many profitability indicators are below the targets and the IRR and NPV10 are well below minimum requirements, in particular for the Chicago Project. It is therefore highly unlikely that investors would go forward with this project under Status Quo fiscal terms.

The main focus of the stranded gas contract is to improve significantly the economics under the stress price.

This is mainly being achieved by taking the royalty and production tax gas in kind and assuming directly the shipping and marketing obligations of the gas. In order to balance this commitment the State participates directly in the midstream project for 20%.

The ASGFC option would result in acceptable profitability indicators for Alberta Project. The Chicago Project would be a very weak project with a very low IRR and modest NPV10. Economics somewhere between the Alberta and Chicago Projects create a viable project. Therefore, the ASGFC option results in acceptable conditions at the stress price.

By providing additionally the PPT credits on the GTP and lateral lines the profitability indicators improve enough to make also the Chicago Project more attractive. Therefore, the ASGFC+GTP option would create economics under the stress price that are well in excess of minimum requirements.

What about cost overruns?

The table below shows the same table as above but now with a 10% cost overrun for capital and operating expenditures.

Minimum Criteria and the Alaska Gas Project in real 2006 $
At $ 3.50 stress price - 10% cost overruns

		Target	Status Quo Alberta	Status Quo Chicago	ASGFC Alberta	ASGFC Chicago	A+GTP Alberta	A+GTP Chicago
IRR	(%)	13%	**10.9%**	**9.6%**	**12.5%**	**11.0%**	13.0%	**11.3%**
NPV10	($ million)	2500	**924**	**-819**	**2128**	**1171**	**2471**	**1514**
PFR10	($/$)	1.15	**1.09**	**0.97**	1.25	**1.09**	1.29	**1.12**
NCF	($ billion)	20	49.7	60.8	49.0	58.6	49.6	59.1
NPV10/BOE	($/barrel eq)	0.33	**0.13**	**-0.07**	**0.29**	**0.16**	0.34	**0.21**
NPV10/Capex	($/$)	0.12	**0.05**	**-0.02**	0.12	**0.05**	0.14	**0.06**
NCF/BOE	($/barrel eq)	2.50	6.76	8.27	6.67	7.96	6.74	8.03

Under the stress price and a 10% cost overrun both the Status Quo and ASGFC options are unattractive. The ASGFC+GTP option is very marginal.

This indicates that cost overruns are a very serious risk.

This also illustrates that even with a stranded gas contract it remains essential for the investors to lower costs and take extensive preparatory steps in order to avoid such cost overruns.

What is also clear from the table is that under these conditions the main attraction of the project is the very large net cash flow and the attractive NCF/BOE results.

The profitability "anchor" of the Alaska Gas Project is therefore the attractive net cash flow.

However, this makes fiscal stability essential. Investors have to be able to count absolutely on the attractive net cash flow in order to pull the project through under possible dismal downside conditions.

Gas Line no longer economic: current situation

The economics of the gas line have deteriorated very significantly since the report. The April 17, 2007 was based on a total costs for the line of $ 20 billion to Chicago in 2003 dollars. In 2005 and 2006 this number was already subject to considerable cost escalation as was reported by me to the Legislature. The above mentioned report already included cost escalation analysis up to 50%. It was already concluded at that time that a cost escalation of 50% would make the project totally uneconomic.

Cost escalation of the Mackenzie Gas Line is reported to have been in excess of 100%. This is mainly due to the considerable stress experienced in Alberta due to the boom in oil sands development. However, also on a world wide basis, there have been considerable increases in costs, in particular in steel prices.

If we assumed a cost escalation of 100% also for the Alaska Gas Line, the pipeline would cost today probably about $ 40 billion. It is possible that the cost escalation for the Alaska Gas Line is less, but this remains to be evaluated.

The forecast of gas prices has not changed in the same manner. In order to create the same economics as presented in the April 17, 2006 report, we need to essentially double the gas prices. In other words, we need to believe in a stress price of US $ 7 per MMBtu, an average price of US $ 11 per MMBtu and a high price of US $ 17 per MMBtu.

As can be easily noted, current market developments are well below this required gas price range. In effect, the Henry Hub is today about US $ 6 - 7 per MMBtu and this seems a reasonable average gas price forecast, with considerable possibility for lower prices in the future. Therefore, today a stress price of US $ 4.50 per MMBtu would be more appropriate.

It is clear from the previous economic analysis that a $ 40 billion line would be totally uneconomic under a stress price of US $ 4.50 per MMBtu or even US $ 5 per MMBtu. Even if escalation proves to be somewhat less, the line would be uneconomic.

However, also troubling for the gas line project is that North American gas prices have now clearly disassociated from crude oil prices, which means on a Btu equivalent basis they have become much lower than crude oil prices. It means that the oil project portfolio of the major oil companies is now considerably more attractive compared to the Alaska gas line than before, resulting, for instance, in the boom in oil sands development.

I do not see much future in LNG from Alaska. The reason is very simple. The world LNG trade related to North America is now becoming a Henry Hub based market. For instance, spot cargoes from Australia are reaching the US Gulf based on Henry Hub less re-gasification costs. Regular cargoes from Qatar, Egypt and other locations are now Henry Hub based. If Australia and the Middle East have no problem delivering to the US Gulf for Henry Hub, than they will have no problem competing with Alaska in Asia. Therefore, the only rational market for Alaska LNG remains the US West Coast. As was analyzed extensively before, this option is even less attractive than the Alaska gas pipeline.

For these reasons, I believe that the only realistic option today is Gas to Liquids.

Of course, I hope for Alaska that I am wrong on my views and that there are opportunities or factors that I did not consider.

SB

2001

(FILE 20)

ALLIANCE

THE ALLIANCE

... for responsible development of Alaska's Oil, Gas & Mineral Resources

SENATE TESTIMONY
on SB 2001
October 23, 2007

Thank you, Chairman Huggins. My name is Paul Laird. I'm general manager and testifying on behalf of the Alaska Support Industry Alliance, a trade organization representing companies and individuals that provide goods and services to Alaska's oil, gas and mining industries.

Our members range from small local contractors and vendors to the largest Alaska Native and Alaska-based corporations to the Alaska subsidiaries of multinational service companies. Our members don't make the multibillion-dollar investments in oil and gas development that fuel Alaska's economy ... our 400 member companies and their 35,000-plus Alaska employees make those investments work.

In turn, those investments put our members and their employees to work.

As companies and workers whose livelihoods depend on oil and gas investment, we're deeply concerned about constant changes in fiscal policy that put some investments at risk.

As Alaskans whose economic future depends on the level of oil and gas production in our state, we're deeply concerned about the impact of an even steeper rate of production decline on our families' and our own ability to build long-term futures here.

Chairman Huggins, members of the Senate Resources Committee, I will be brief in my remarks to you today. We don't know if a 22.5% tax rate with the current escalator and credits strikes the right balance between ensuring the state its fair share of OIL revenues and encouraging long-term investment and production. We don't know if 25% is the right rate ... or 20 ... or 15.

None of us does ... not the Alliance, not the legislature, not the administration and not even the producers. Regulations for the Petroleum Production Tax system just 14 months ago haven't been finalized, and the first returns haven't been audited.

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It's difficult for us to understand why we're back here so soon to fix a system that hasn't even had time to work, let alone for there to be compelling evidence that it's broken. That case simply hasn't been made; you've been presented with a plethora of projections and a paucity of proof.

We do know that the PPT has already generated an additional $1 billion in state revenues.

We do know that the increase being proposed would be the third major severance tax increase on the industry in the past three years.

We do know that every dollar in additional taxes is a dollar that won't be invested in sustaining production, in creating business opportunities for Alaska companies like Alliance members, in generating good-paying private sector jobs for Alaskans.

We do know that throughput in Trans-Alaska Pipeline has already declined by two-thirds, and despite multibillion-dollar investments by the industry, it continues to decline by 6% a year.

We do know that without those investments, TAPS will reach its economic threshhold in the next 15 or 20 years instead of the the next 50 or 60.

We do know that our 400 members and many of their 35,000 Alaska employees want to be here long after the legislature's and the administration's consultants on this issue are gone ... as long as there are still enough economic opportunities to keep them here. They'll be the ones to bear the consequences if higher taxes and higher costs really do result in less investment ... a novel economic concept, to be sure.

We do know that while the extent to which yet another tax increase will discourage investment is debatable, the fact that it will do absolutely nothing to encourage new oil production and construction of a gas project is not.

Isn't that what this discussion should be about, Mr. Chairman and members of this committee: how we can work together to promote investments ... how we can ensure our "fair share" of long-term jobs and business opportunities for Alaskans, rather than how much more money we can extract from the private sector without further risking our long-term future ... just so state government can have more money to spend in the short term?

What's the plan when this $700-900 million a year tax increase isn't enough to sustain state spending?

In your wisdom, when you adopted the new PPT in 2006 after six months of extensive deliberations, aggressive debate and countless votes, you included provisions requiring a complete review of the system five years later - in 2011. You understood then that it would take several years to reasonably determine how and if it's working.

So far, there's been no compelling evidence to the contrary. It will still take several years to responsibly make that determination.

Do what you need to do in the short term to make the PPT work - hire more auditors, pay them more, take steps to ensure the timely flow of accurate data from the producers to the state, authorize the state to buy back credits.

But on behalf of the Alliance's 400 member organizations and their 35,000-plus Alaska employees, all Alaska businesses and workers and Alaska's economic future, we urge you to reject premature, fundamental changes to the PPT that will increase taxes, increase costs and jeopardize the economics of critical long-term investments and put production, Alaska jobs and business opportunities at risk.

Thank you.

SB

2001

(FILE 21)

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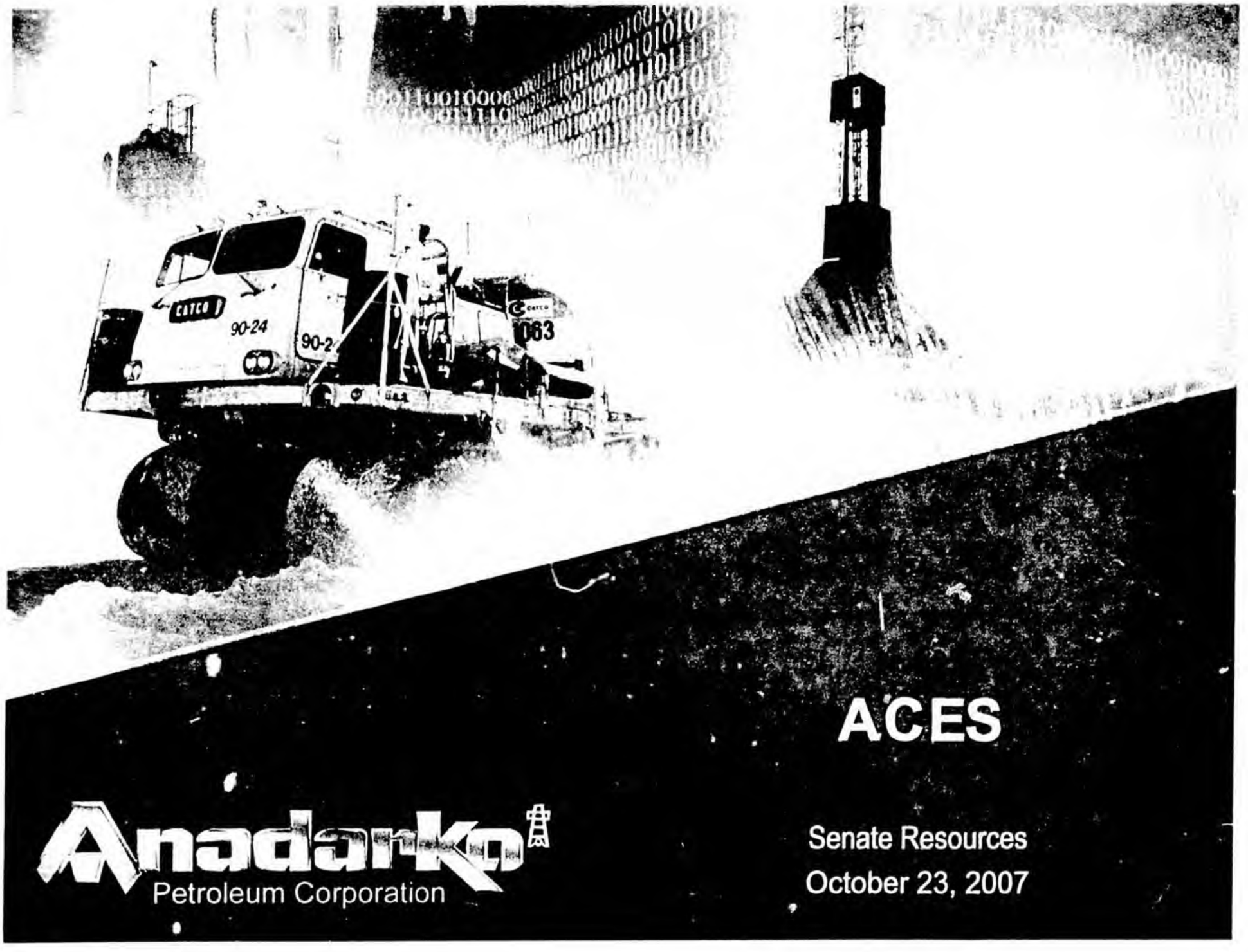


ACES

Anadarko
Petroleum Corporation

Senate Resources
October 23, 2007

APC Operational Overview

Rockies
- Large acreage holdings

International
- World class targets
- Focused exploration

ANADARKO

Alaska

Onshore U.S.

Gulf of Mexico

Tunisia

Algeria

China

Qatar

Trinidad

Brazil

Indonesia

Sub Sahara Africa

ANADARKO HQ
Houston, Texas

Gulf of Mexico Deepwater
- Significant Acreage position

Exploration Areas

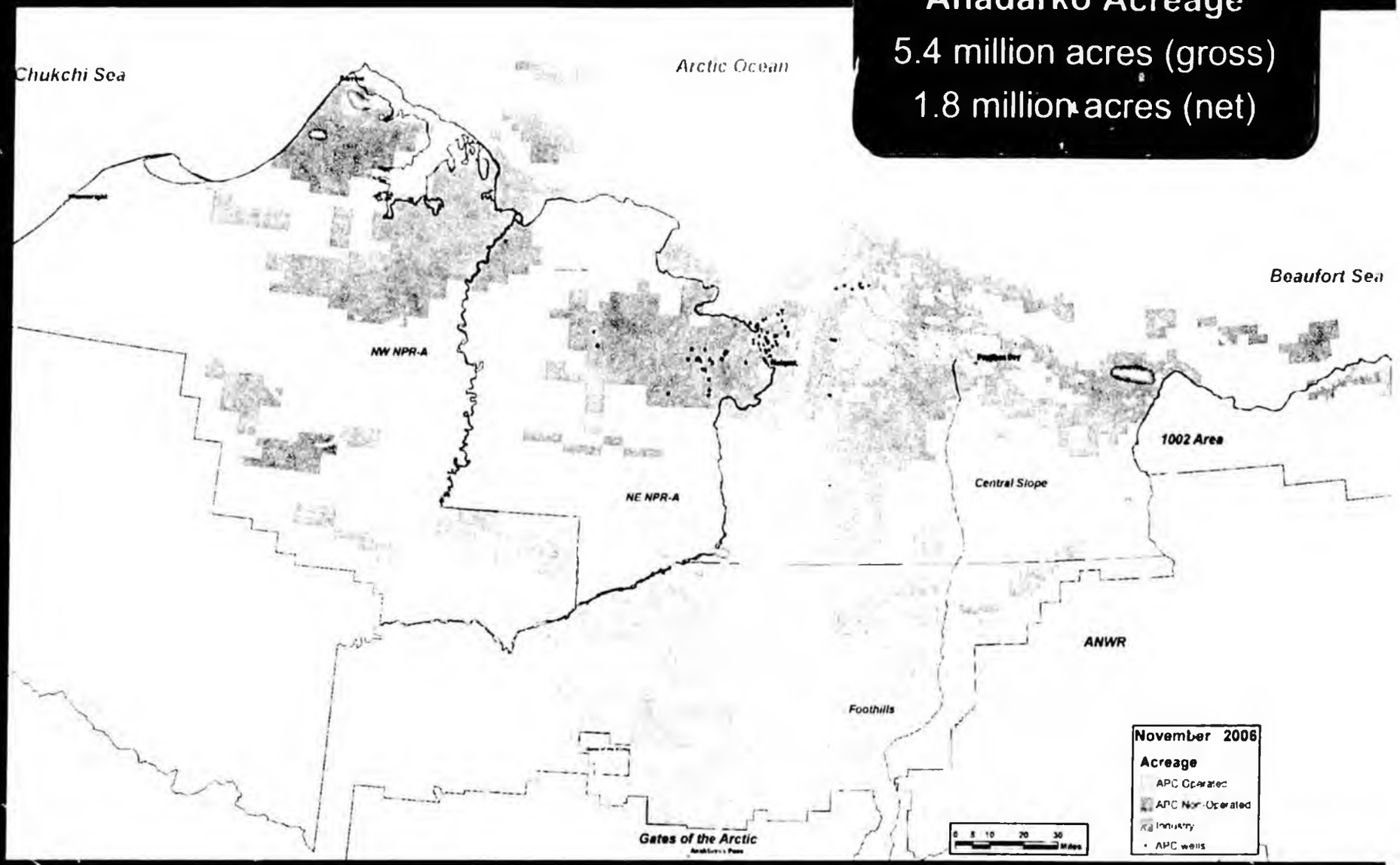
Producing Areas

Anadarko's Investment in Alaska-Land

Anadarko Acreage

5.4 million acres (gross)

1.8 million acres (net)



Alaska Opportunities

- World class petroleum basin
- Significant remaining resource potential
- Legacy type prospectivity (i.e. Anchor Fields)
- New entrants/partnering opportunities
- APC possesses tangible competitive advantages

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Alaska Challenges

- Maturing basin/materiality/smaller prospects
- High costs
- Lack of infrastructure and competition
- Extremely long lead-time exploration
- Seasonal drilling & regulatory timing requirements
- Distance from market
- Lack of gas transportation

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Our View of PPT & Recap of 2006 Testimony

- **Significant tax increase at existing fields**
  - *Can be offset by increased exploration & development investment*
- **Improvement in exploration economics versus elf system encourages new investment**
  - *Credits help reduce high costs & improve NPV*
  - *25 – 20 worse than old elf system*
- **On balance supportive of PPT system**

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Support Net Profits Approach

- **Appreciate Administration work to evaluate gross vs. net and conclusion to stick with net**
- **Net considers varying economics & costs**
  - *Tax paid on net income after costs*
    - *Accounts for costs and levels playing field*
    - *Still doesn't account for risk*
- **Gross collects on income regardless of profit**
  - *Gross tax with proper incentives harder to develop equitably and still complicated to administer*
- **Royalty acts like a gross tax**

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Our View of ACES- Negatives Outweigh Positives

- **Support some parts of ACES**
  - *Expand time to qualify for Exploration Incentive Credits (offset by new exclusions and requirements)*
  - *Modify Net Loss carry forward to create level playing field*
  - *Goal of increased transparency & state auditor capability*
- **Stability**
  - *Concern that PPT/ACES will be revisited again in next few years to deal with gas*
    - Gas definitely needs to be addressed, but will reopen everything again
- **The significant tax increases would decrease exploration & development economics and far outweigh any positives in the bill**
  - *Tax rate increase*
  - *Tax escalator changes increase costs*
  - *Transition Investment Expenditure Credits Elimination*
    - Fairness and Investment Impact

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