

SB

2001

(FILE 5)

**MISC. MEMOS
& NOTES**

Alaska's Clear and Equitable Share (ACES) Proposal A Brief Review of the Governor's Proposed Changes to Oil Taxation

This review is a simplified explanation of the fiscal impact of major issues addressed by ACES. It is not intended to address every issue or to offer a complete technical discussion of the major issues.

The ACES bill addresses four major items:

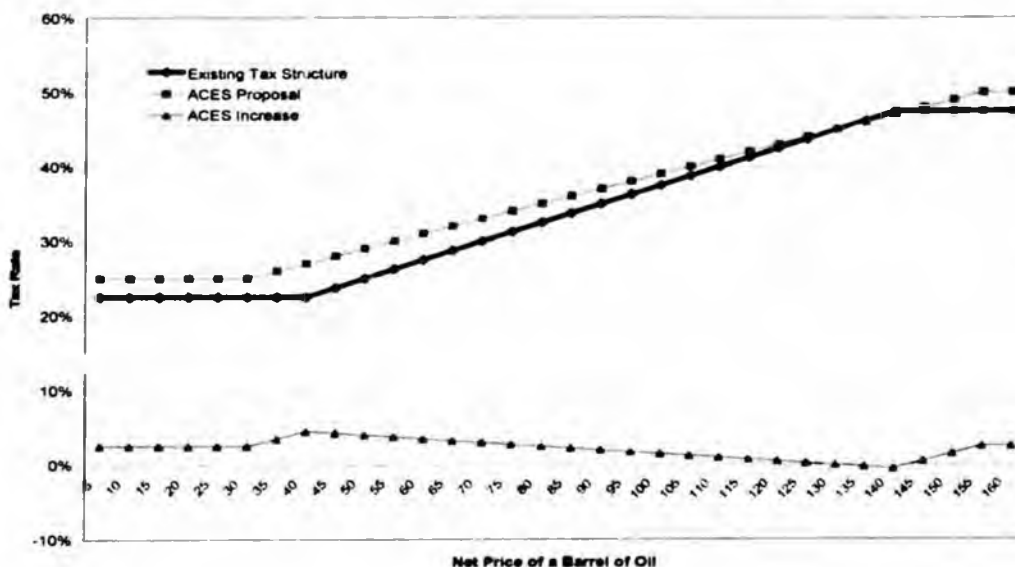
1. Base tax rate
2. A surcharge that increases revenue at higher oil prices
3. Tax credits, and
4. Information provided to the Department of Revenue.

1. Base Tax Rate. ACES raises the base tax rate from 22.5% to 25% of the profit on oil production. ACES also increases the minimum tax to 10% of the gross value of oil production (rather than profit) from the Prudhoe Bay and Kuparuk fields. PPT has a sliding scale that eliminates the minimum tax when oil prices are \$15 per barrel or less. The ACES minimum tax rate offers better protection for the state (i.e., about 10% more revenue than PPT) if oil prices fall to very low levels.

2. Surcharge. Under PPT, a surcharge adds 0.25% to the base tax rate when the profit per barrel exceeds \$40. ACES lowers the price level at which a surcharge is triggered, but also reduces the surcharge rate when oil prices exceed the trigger point. Under ACES, the surcharge adds 0.20% to the base tax rate when the profit per barrel exceeds \$30.

The impact of changes to the base tax and surcharge are shown in Figure 1. ACES produces a higher tax rate at net prices below \$130 per barrel or above \$145 per barrel.

Figure 1. Tax Rates Under Current Law and ACES



As a rule of thumb, add \$24 per barrel to the net prices shown in Figure 1 to obtain the selling price of ANS crude. ACES calculates the surcharge on the average annual price rather than monthly price as under PPT. Unless prices and production are highly volatile, the change in methodology should have relatively little impact.

The relevant portion of the chart for the near-term is between \$30 and \$80 per barrel, which is roughly equivalent to West Coast market prices of \$54 to \$104 per barrel. In that range, the total tax rate under ACES would average about 3.5 percentage points higher than under PPT. The maximum difference occurs when ANS crude sells for approximately \$64 per barrel (profit of \$40 per barrel), which is near the Department of Revenue's mid-term forecast. Because the surcharge rate under ACES is lower than under PPT, the difference in the total tax rate declines as the net price of oil increases.

The question begging discussion is whether ACES should be considered a tax increase. Figure 1 clearly shows that production taxes are generally higher under ACES than under PPT, but there is another factor to consider. That factor is that annual revenue under PPT is about \$800 million less than anticipated.

ACES will generate more state revenue than the tax system the legislature implemented (PPT), but less state revenue than legislators *thought* they would get from the tax system they implemented. Those that argued that PPT provides an insufficient amount of oil revenue to the state will almost certainly point out that anticipated revenue under ACES is below levels anticipated under PPT. These people will argue that ACES is not a tax increase; it is a partial correction of a compromise that was based on inappropriate or inaccurate information.

On the other side of the argument, people will focus on the *share* of revenue rather than on the *amount* of revenue that goes to the state. State revenue under PPT is less than anticipated because the profit per barrel is much less than anticipated. Legislative Finance does not have the data required to determine whether or not actual shares of revenue are close to what was anticipated under PPT, but it is obvious that unanticipated production costs—which reduce profit and therefore reduce state revenue—do not accrue to the producers. From the perspective that ACES has generally higher tax rates than PPT (so increases the state share of revenue and reduces the share retained by producers at any given levels of price and costs of production) it is clear that ACES is a tax increase.

Converting *tax rates to revenue impacts* provides a less accurate (but more interesting) view. The following graphs are based on a simple model that holds production constant at 244 million barrels annually and deductible costs of production constant at \$23.85 per barrel—numbers based on data published in the Spring 2007 Revenue Sources Book.

Figure 2 shows that changes to the base and surcharge tax rates under ACES can be expected to increase revenue by \$450 million to \$515 million annually in the \$65 to \$100 market price range. That amount is based on current levels of production and excludes

the impact of potential changes to tax credits. Revenue under ACES (relative to PPT) will fall if oil prices exceed \$90, going negative at prices between \$155 and \$165.

Figure 2. State Revenue Change Under the ACES Proposal

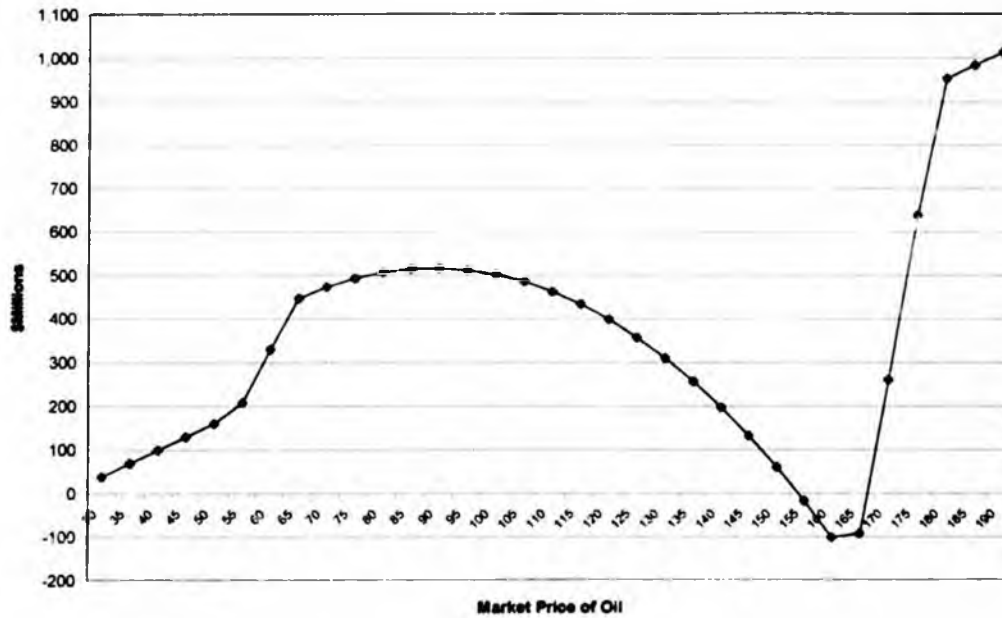
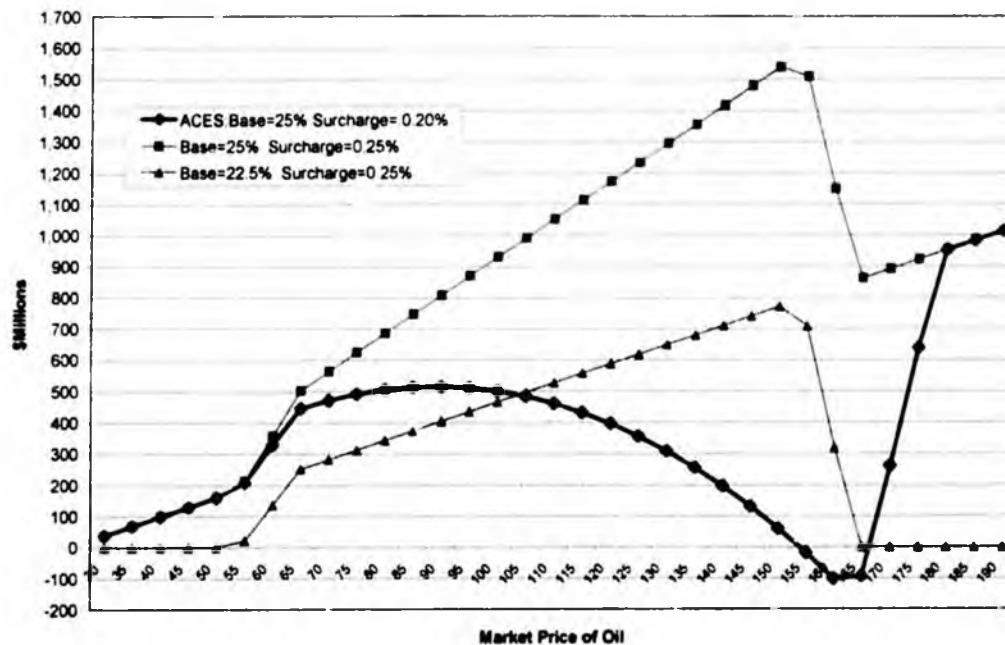


Figure 3 shows the sensitivity of revenue to changes in the base and surcharge tax rates. Adopting a 25% base rate and a \$30 trigger point without reducing the surcharge rate

Figure 3. State Revenue Change Under Variations of the ACES Proposal



would generate significantly more revenue than PPT (or ACES) at all oil prices above \$60. Retaining a 22.5% base rate and 0.25% surcharge rate while adopting a trigger point of \$30 would generate less revenue than ACES at oil prices below \$105, but more revenue at higher oil prices.

With variations in the base rate, surcharge rate and trigger point(s), the revenue curve can be designed to reflect whatever policy the legislature desires.

3. Tax Credits. Credits are arguably the most complex topic in the bill. A discussion of the fiscal impact of changes to tax credits would require knowing the amount (and type) of eligible credits that might be claimed. Legislative Finance does not have sufficient information to make projections. It should be clear, however, that reducing credits will increase revenue by more than indicated by a comparison of tax rates. In the figures above, the ACES line would be higher than shown if producers were allowed to claim fewer credits.

There are three types of tax credits. ACES makes a number of changes to tax credits as discussed below:

1. **Transitional Investment Credits.** These credits are for eligible capital expenditures incurred during the five years prior to the enactment of PPT. Statements in the press argue that because past investment events cannot be affected by changes to the production tax, these credits are essentially bonuses that reduce the tax liability of the major producers. ACES eliminates transitional credits.

Legislative Finance has no projection of the value of transitional credits that would be claimed under PPT or the value of credits that ACES would eliminate, but a few conceptual statements may clarify the analysis. The credits:

- are capped by time (they expire in 2013), by the amount invested in the transition period and by the amount invested in future years.
- are not simply giveaways; they cannot be claimed without additional investment.
- can be viewed as one-time bonuses that have no long-term impact on the tax structure.

Lest these points be taken as supporting retention of the credits, it should be noted that the credits are likely to cost the state several hundred million dollars in lost revenue.

2. **Direct tax credits.** These credits are deducted directly from producers' tax liability. The state has little control over the amount of the direct credits applied; they require no appropriation and are deducted from revenue projections.

Under ACES, tax credits remains at 20% of qualified capital expenditures, but no more than half the credit may be applied in any single year. This change may reduce volatility in the amount of credits applied in a given period and increase

the accuracy of revenue forecasts, but it has no significant long-term fiscal impact.

The allowable credit applied to a carried-forward annual loss is increased from 20% to 25% of the loss. This increase in available credits is offset by excluding losses based on lease expenditures in legacy fields. Legislative Finance has no projection of the fiscal impact of this change.

3. **Transferable tax credits.** These credits are generally applicable to small producers who make qualified expenditures but whose current tax liability is insufficient to apply the credits to their tax bill. Under PPT, small producers can claim a cash refund or sell/transfer the credits to a producer with tax liability sufficient to apply the credits. ACES eliminates the credits/refunds limit of \$25 million per applicant per year.

ACES establishes a new fund designed to ease the process of claiming/purchasing transferable tax credit certificates. Approximately \$100 million to \$200 million (dependent on the price of oil) would be appropriated annually to the fund. The Department of Revenue can use the fund to purchase eligible certificates, presumably without further appropriation. If the Department expects to expend the fund without further appropriation, a statement to that effect would reduce uncertainty regarding the need for an appropriation from the fund and the status of the fund with regard to the constitutionally mandated sweep of available general fund balances to the Constitution Budget Reserve Fund.

An appropriation to purchase transferable credits was an item of contention in the FY08 budget process. The governor proposed an open-ended appropriation to pay for an estimated \$25 million in claims. The legislature capped the appropriation at \$25 million, but left the appropriation for FY07 open-ended. Based on the amount of credits purchased in FY07, a supplemental appropriation of \$75 million may be required for FY08.

4. **Information requirements and other changes.** ACES includes several significant changes to the information that producers must provide to the state. The bill also includes several technical and conforming changes, and addresses unscheduled production interruption costs and auditing requirements of the Department. Explanation of these topics is best left to the Department of Revenue: the fiscal impact of such changes is minor relative to the impact of changes to tax rates and credits.

10-10-07

ACES Brief - Gous Confm - Atwood Bldg Anch

- Galvin, ^{P.} ^{M.} Davis, ^{Sen} Ellis, ^{Sen} Stevens, ^{Sen} French, ^{Sen} Olson, ^{Sen} Wielech, ^{Sen} Thomas, ^{Sen} Green, ^{Sen} Stedman, ^{Sen} Huggins, ^{Sen} L. Hoffman - multiple staff

- Galvin ^{current} PPT not stable.

- lack tools we need to adeq implement requirements of law
- gross base tax ^{does} not deliver flexibility to exercise economic drives necessary to sustain future exploration & dev
- gross tax "off the table" (Q by Green)
- tried multiple permutations of tax mechanisms including separating gas & oil = unmanageable
- gross "floor" kicks in in low price/high cost circumstances

- ACES

Q. Hoffman - did u consider effect of this on

! Galvin gasline - won't effect cost of line - may affect economics of fields

- we'll acquire cost data in AGIA apps & during open season which will show effect on gas development -

- gas field economic analysis will be worked back from tariff

Q Sted: does it disadvantage use to set rate prior to apps

Can they provide copy of "ACES Powerpoint"

Stedman - 30¢ barrel -

Galum - 30¢ revolved around "regular maintenance costs" - 30¢ was a proxy for ongoing maintenance (so we wouldn't have to constantly be auditing those)

dir: tax division - John Drensen - to Hollis F Q. re: nature of CO's tax returns
tax return is not itemized - items would be revealed thru audit

C.H. we're addressing symptoms to which we have no details

L. Hoffman: - this is rewrite of PPT -
will be quite difficult to accomplish in 30 days

- C.H. - have we banned this off explorers -
Marsha yes - as well as large producers

- G. Starns - What is AK's "fair share"
how do we recognize it?
is it a dollar amt?

Galum - it the line @ highest rate short
of squelching - ^{future} investments & exploration
- can not be based on expectation of a certain # #
- must engender a positive investment environment

Stedman: re: ^{max} dollars in state coffers - state revenue needs
1) positive investment climate

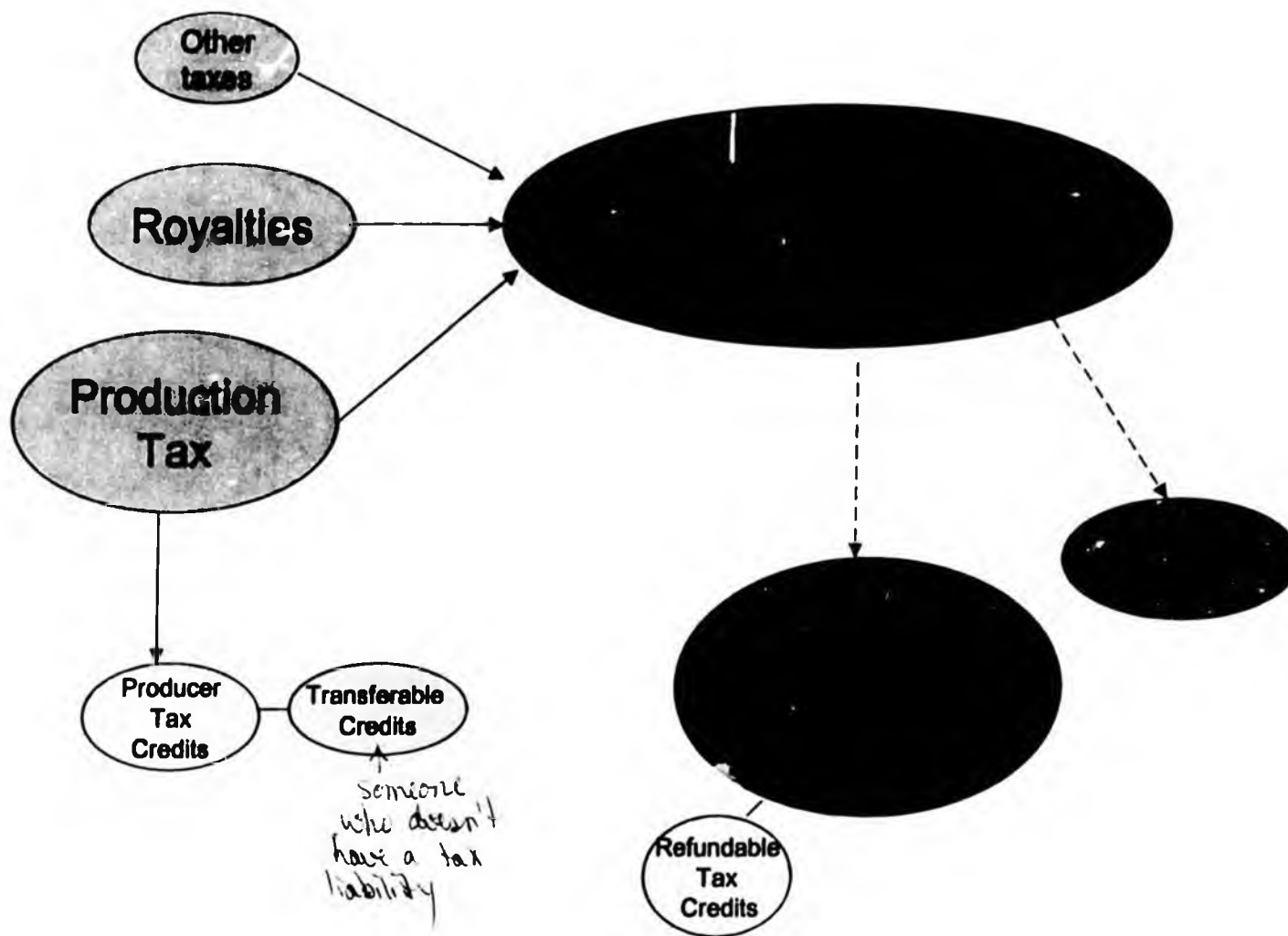
- Galvin - "not based on revenue needs"
- Sted - we'll look @ that when we address "tax floor"

▷ call G. Stambaugh ▷

Jerry Burnett -
DOR
Dir of Administration
@ STUD Oct 30, 2007

Current PPT Payment of Tax Credits

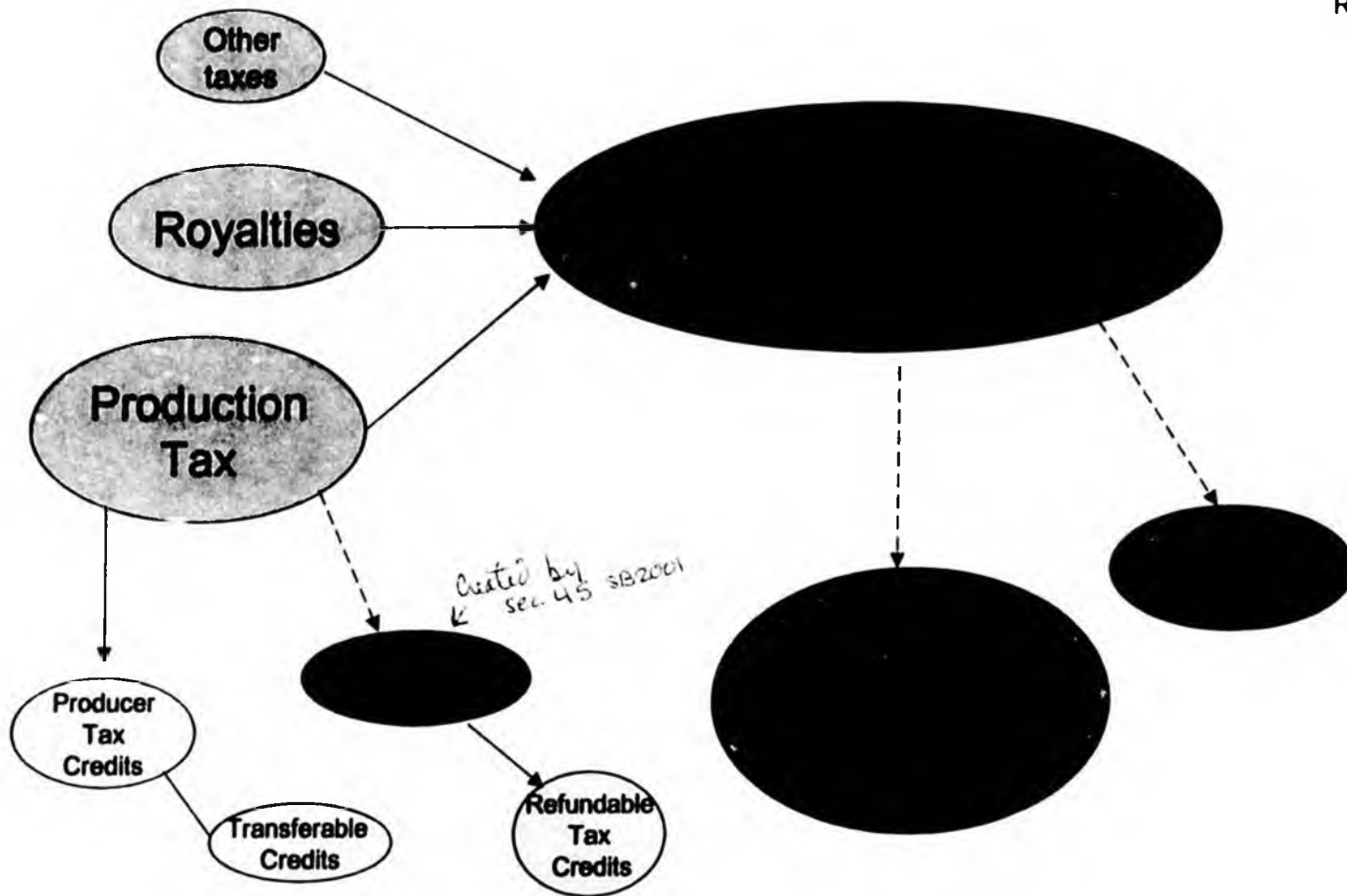
Blue=Revenue
Green=Fund
Orange=Budget
Yellow=Payment
Red Dotted Line=Appropriation



SEES
Gov Sec. 45

ACES Proposal Payment of Tax Credits

Blue=Revenue
Green=Fund
Orange=Budget
Yellow=Payment
Red Dotted Line=Appropriation



Tax Rates and Progressivity

November 8, 2007

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econ
ONE

Key Fiscal Terms

Production Taxes Under Current & Proposed Systems

Tax Rate:

$$\begin{aligned} & \text{Base Rate} \\ & + \\ & \text{Progressivity Rate} \\ & = \\ & \text{Total Tax Rate} \end{aligned}$$

Applied to:

Taxable Value

Key Fiscal Terms

Production Taxes Under Current & Proposed Systems

Taxable Value:

- **Gross Sales Price (West Coast)**
less
- **Transportation Costs from Wellhead**
=
- **Gross Wellhead Value**
less
- **Operating Costs (All Barrels),**
- **Capital Costs (All Barrels)**
=
- **Net Taxable Value**

Key Fiscal Terms

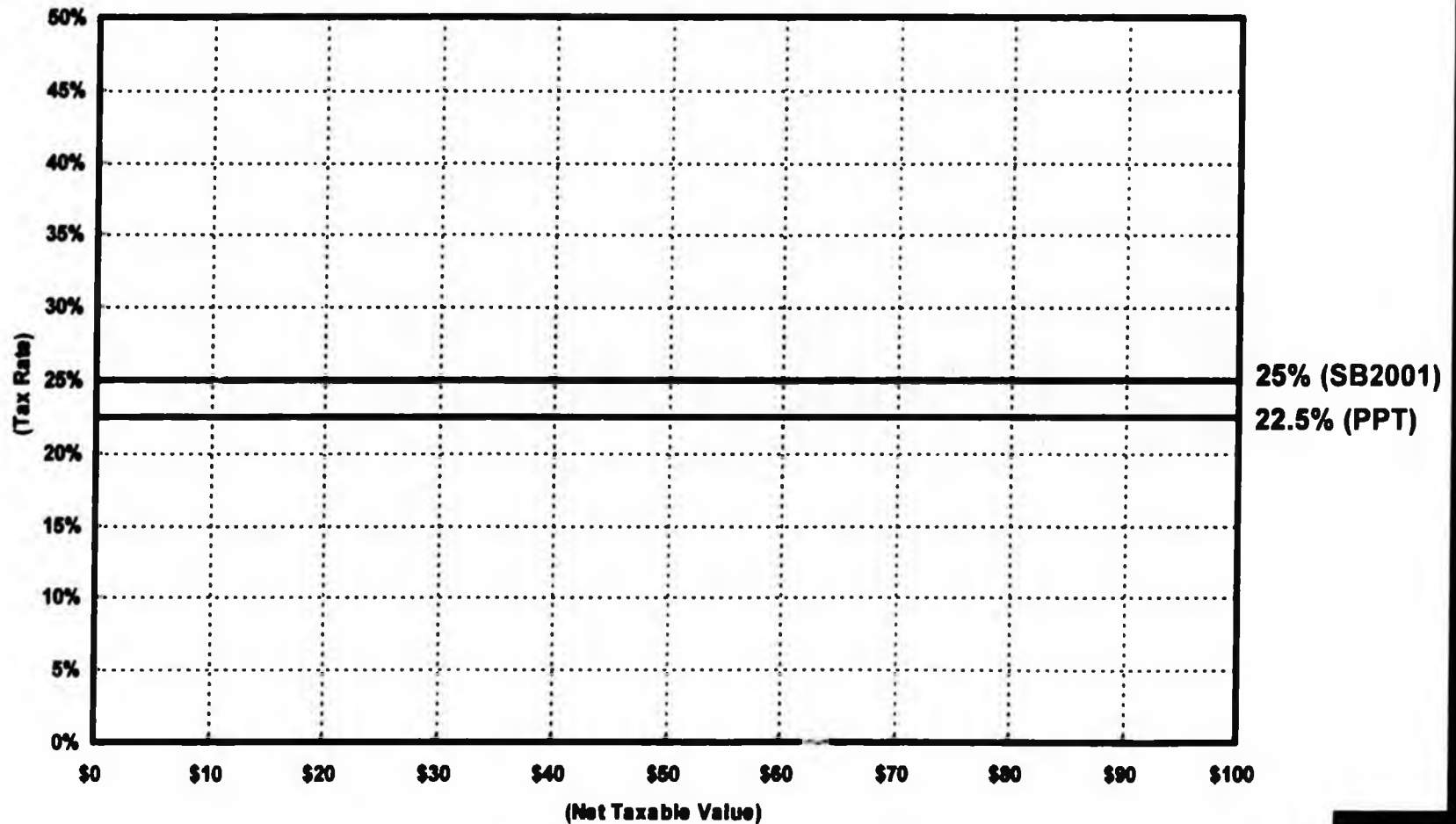
Production Taxes Under Current & Proposed Systems

Other Items:

- Floor
- Capital Credits
- TIE Credits
- Small Producer Credits
- Exploration Credits (EIC)

Base Tax Rate

- **Applied to Taxable Value at All Price Levels**



- **It Does Not Vary with Prices**

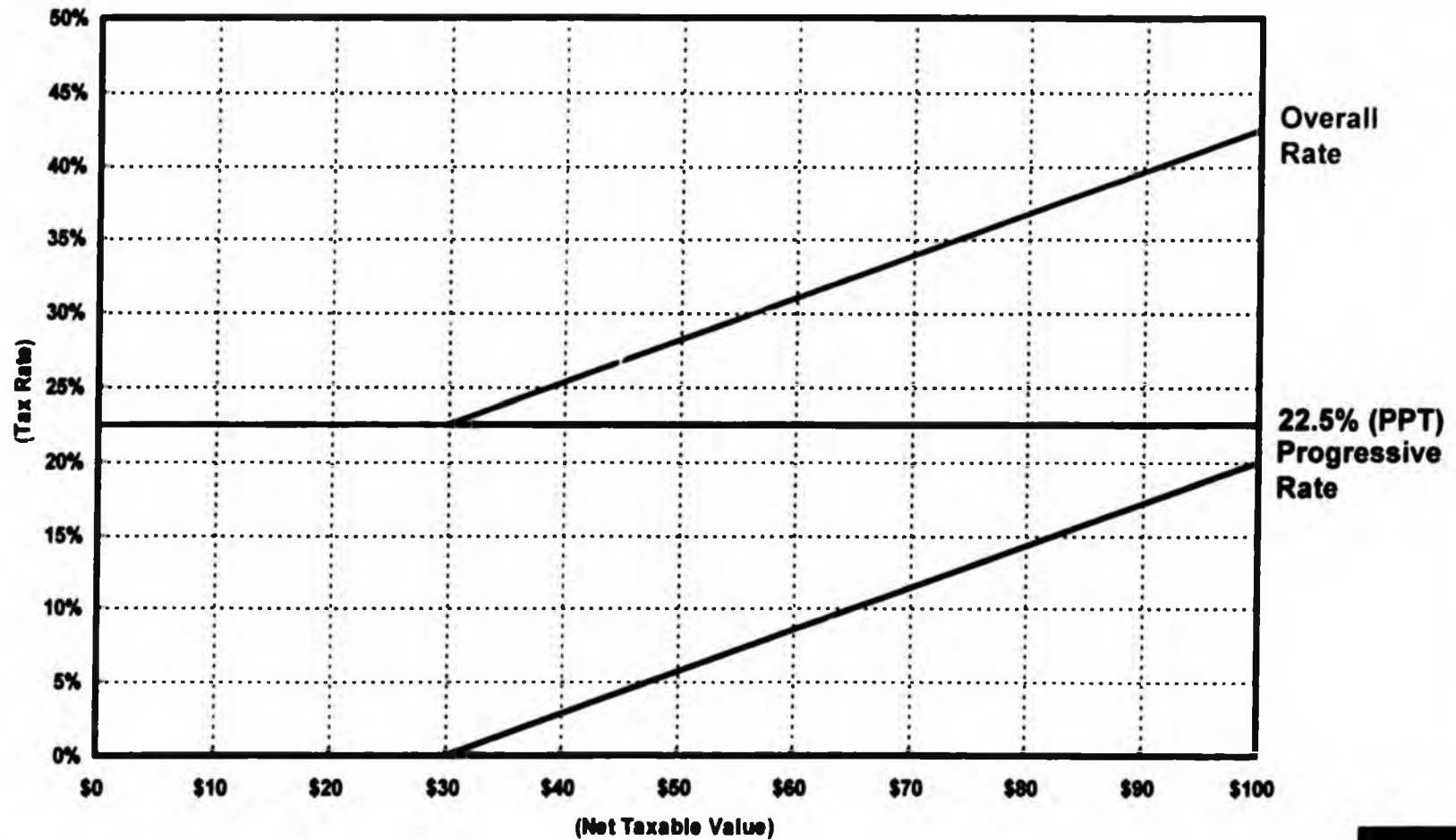
Progressive Tax

	<u>PPT</u>	<u>SB2001</u>
• Trigger Level	\$40(Net)	\$30(Net)
• Slope	0.25% per Dollar	0.20% per Dollar
• Gross or Net Value	Net	Net



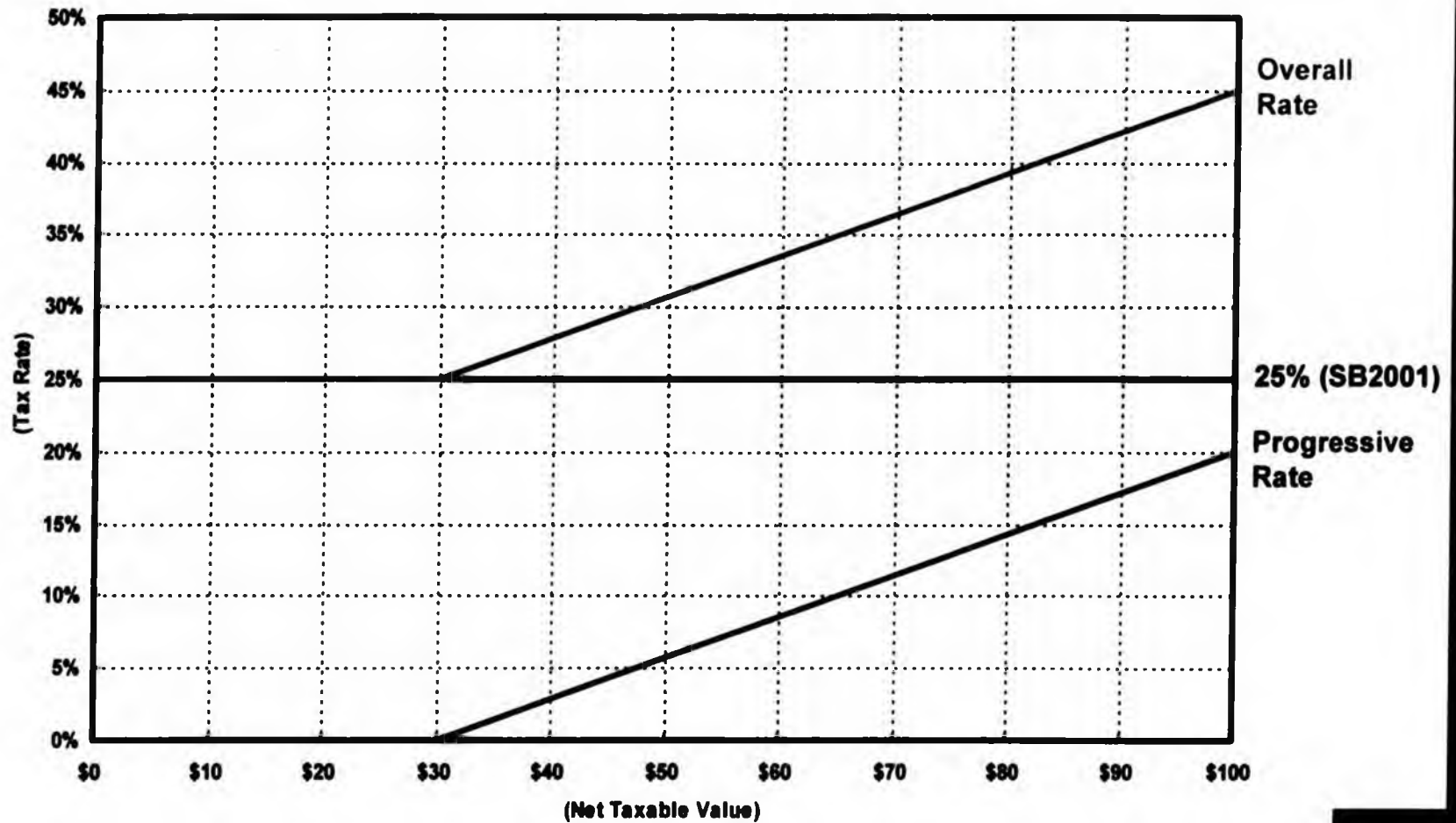
Progressive Tax

- **Example of Progressive Tax Under Current & Proposed Systems**



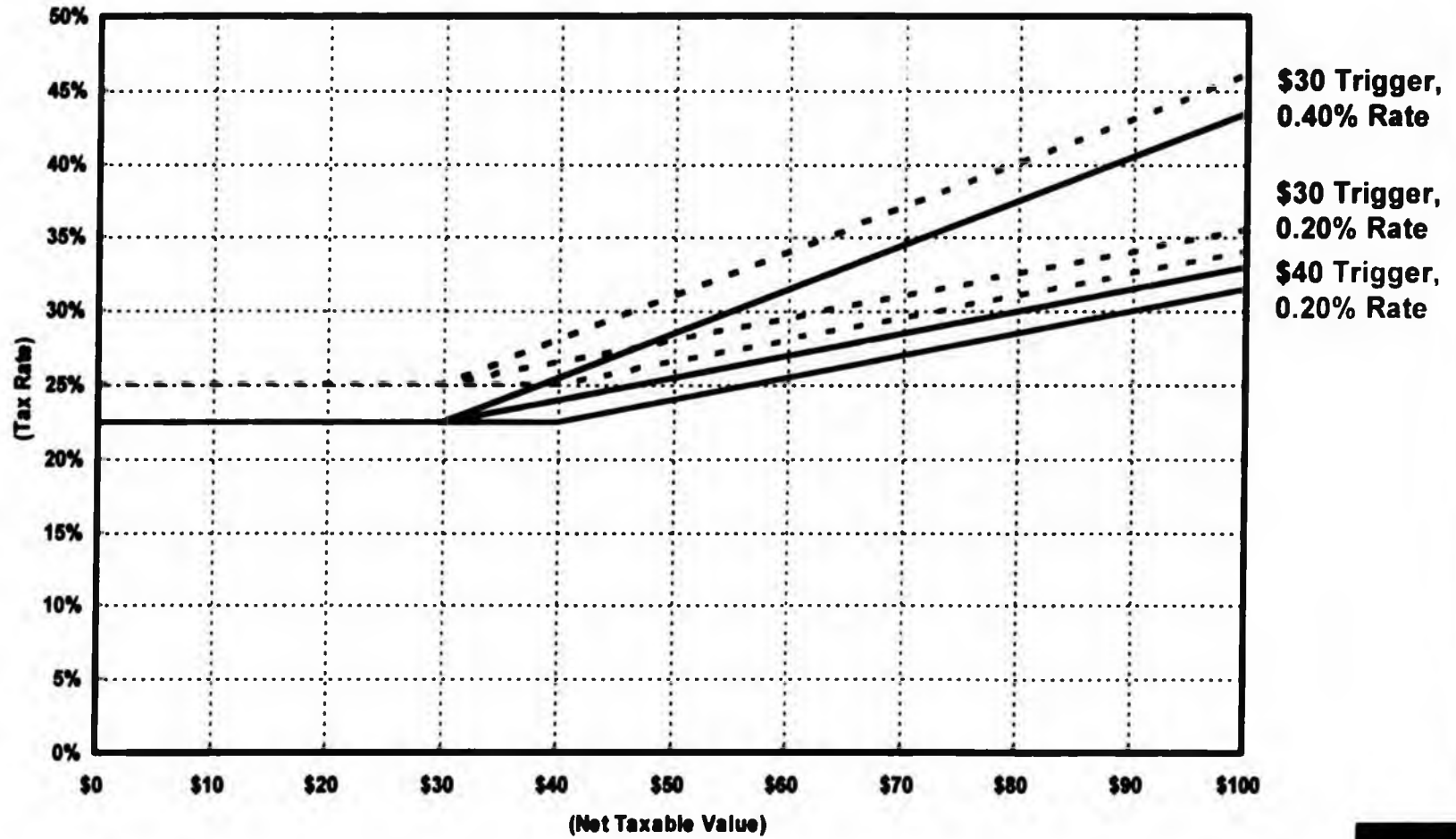
Progressive Tax

- Example of Progressive Tax Under Current & Proposed Systems

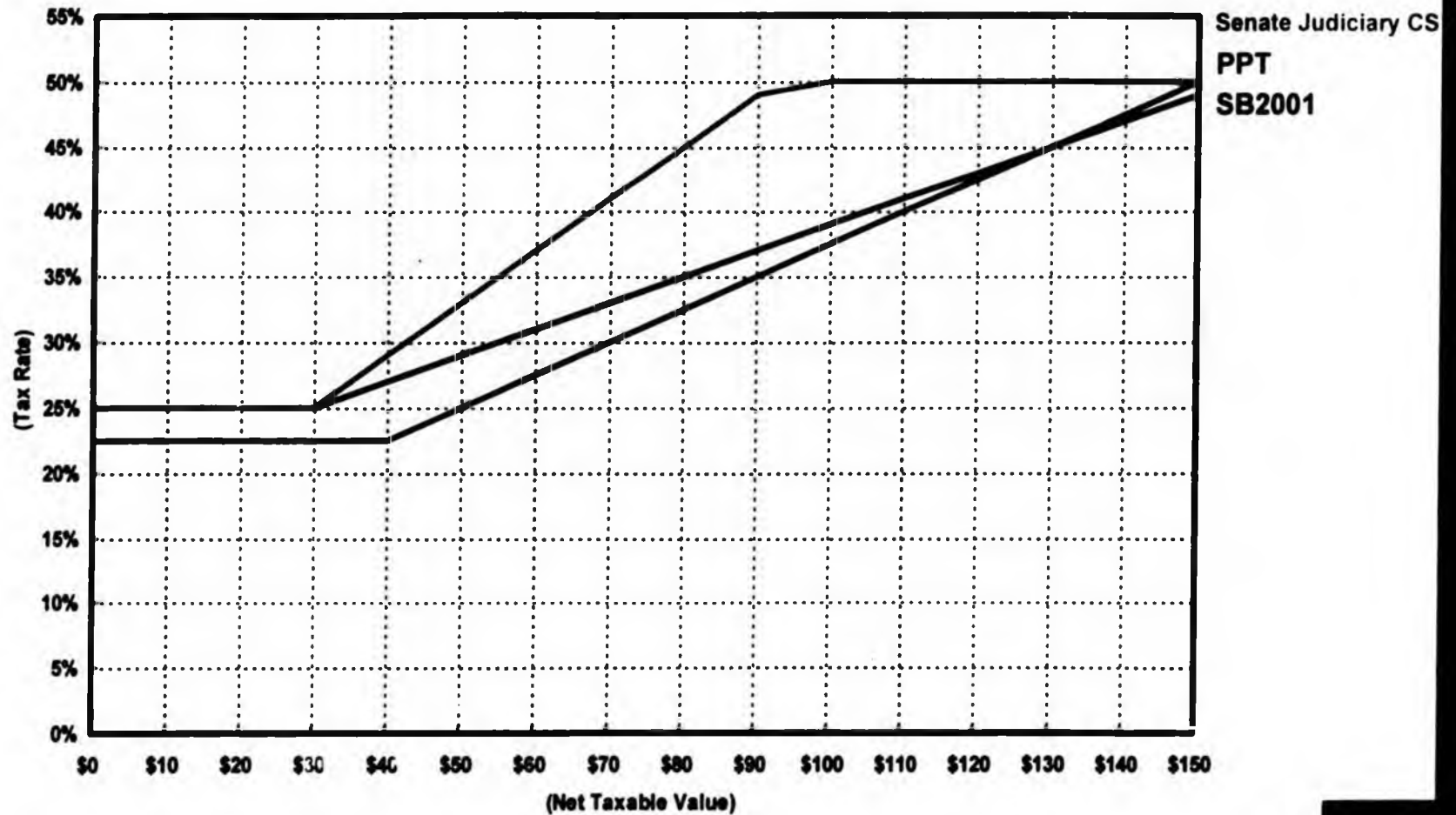


Progressive Tax & Impact on Overall Tax Rate

- **At 22.5% and 25% Tax Rates**

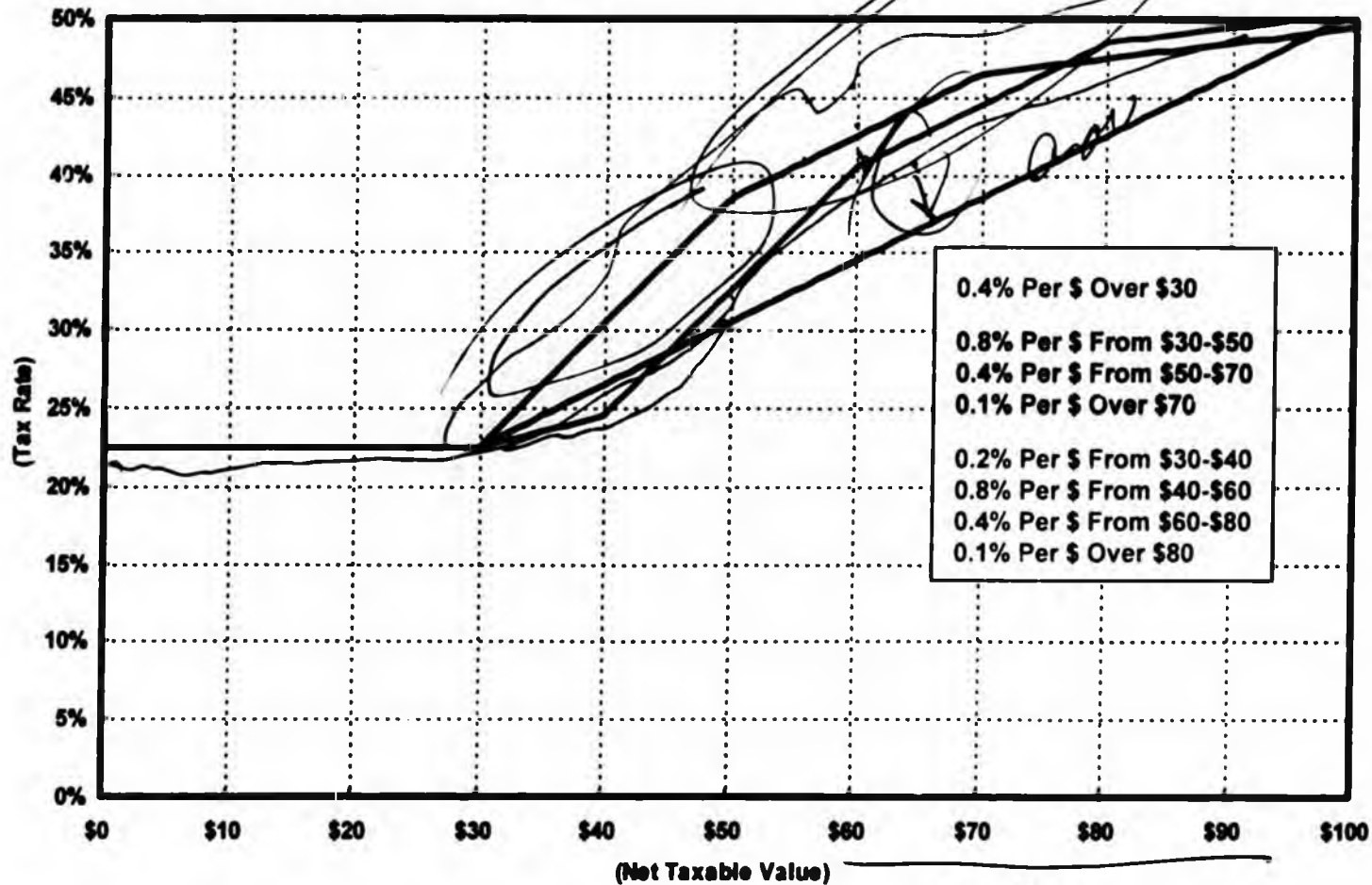


Overall Tax Rates: PPT, SB2001 and Senate Judiciary CS



Progressive Tax & Impact on Overall Tax Rate

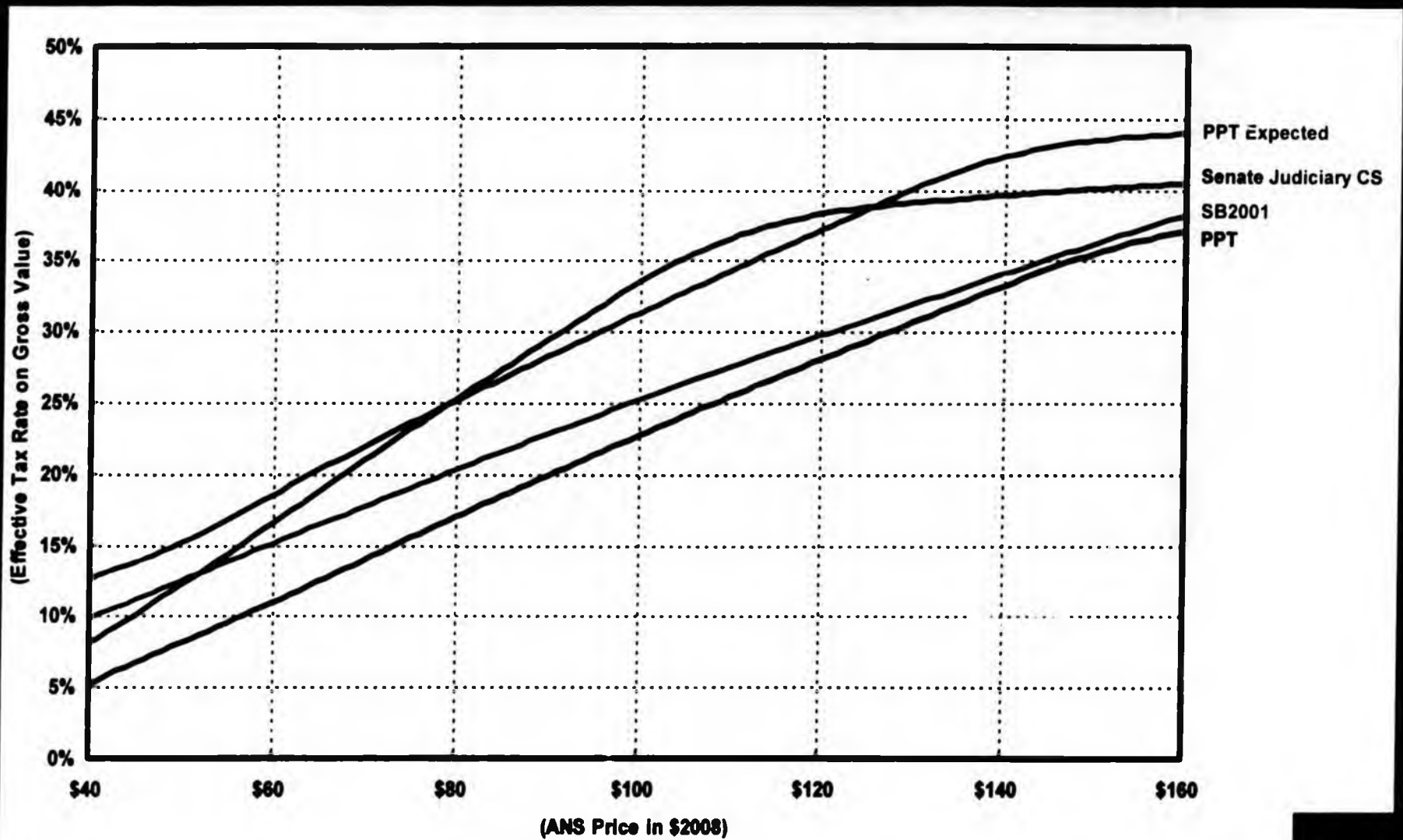
• Assume a 22.5% Tax Rate



22.5

margin

Estimated Average Effective Tax Rate on Gross Taxable Value at Various West Coast ANS Price Levels (FY 2008-2014)



Estimated Average Effective Tax Rate, Government Shares and Revenue Impacts at Various West Coast ANS Price Levels (FY 2008-2014)

Average ANS West Coast Price in Real 2008 Dollars:	\$40.00	\$60.00	\$80.00	\$100.00	\$120.00	\$140.00	\$160.00
Effective Tax Rate on Gross Taxable Value (Percent)							
PPT	5.1%	10.9%	17.0%	22.7%	28.1%	33.2%	37.2%
SB2001	9.9%	15.1%	20.3%	25.2%	29.7%	34.1%	38.2%
Senate Judiciary CS	7.9%	16.1%	24.7%	32.8%	37.5%	39.1%	40.2%
PPT (Expected)	12.6%	18.6%	25.2%	31.3%	37.2%	42.3%	43.9%
Total Government Share of Net Cash (Percent) <i>(State & Fed + Manic)</i>							
PPT	60.5%	60.6%	62.7%	65.3%	67.8%	70.4%	72.2%
SB2001	64.5%	63.5%	64.9%	66.8%	68.8%	70.9%	72.9%
Senate Judiciary CS	62.9%	64.2%	67.8%	71.6%	73.6%	73.8%	74.0%
PPT (Expected)	60.4%	61.7%	64.4%	67.1%	69.9%	72.3%	72.9%
Marginal Government Share of Net Cash (Percent) <i>each 1/10 increase = production tax increase - state's percent take increases</i>							
PPT	58.9%	63.7%	70.7%	75.9%	81.0%	86.2%	78.9%
SB2001	59.7%	65.4%	70.7%	75.1%	79.3%	83.5%	84.9%
Senate Judiciary CS	60.7%	71.5%	79.8%	85.6%	77.2%	74.9%	74.9%
PPT (Expected)	60.2%	68.3%	73.9%	79.4%	85.0%	81.0%	73.0%
Annual Average Tax Difference Above/(Below) PPT (Nominal \$M)							
SB2001	\$423	\$587	\$635	\$608	\$493	\$287	\$423
Senate Judiciary CS	\$251	\$726	\$1,476	\$2,454	\$2,762	\$2,002	\$1,190
PPT (Expected)	\$665	\$1,067	\$1,565	\$2,088	\$2,682	\$3,132	\$2,688

% of net income after costs deducted

% change of govt share w/ price increase

25% tax rate
25%
different progressivity

Hoffman - money isn't in the tax rate but rather in the progressivity slope



Tax Floor Issues

PPT (Current Law)

**1-4% of Gross
Wellhead Value
(\$15 - \$25 WC ANS)**

SB2001 (Proposed)

**10% of Gross
Wellhead Value
(Prudhoe & Kuparuk)**

Senate Judiciary CS

**Same as
Current Law**

- **Presence of Higher Floor Introduces Regressivity at Lower Prices**
- **Is Like an Insurance Policy. What Does it Cost?**
- **What are State's Expectations as to ANS Prices?**

ACES Proposal for Petroleum Taxation
Tax Rate at Various Values of a Barrel of Oil

Base Tax Rate: 22.5%
 Surcharge: 0.25%
 Trigger Point: \$ 40.00
 Maximum Surcharge: 25.0%

Base Tax Rate: [REDACTED]
 Surcharge: [REDACTED]
 Trigger Point: [REDACTED]
 Maximum Surcharge: [REDACTED]

Existing Tax Structure (PPT)			ACES Proposal					ACES Increase									
Market Price	Taxable Value	Net Price	Surcharge Rate	Total Tax Rate	Base Revenue	Surcharge Revenue	Total Revenue	Surcharge Rate	Total Tax Rate	Base Revenue	Surcharge Revenue	Total Revenue	Base Revenue	Surcharge Revenue	Total Revenue	Percent of Revenue	Total Tax Rate
30	1.500	8.15	0.00%	22.50%	337.5	-	337.5	0.00%	25.00%	375.0	-	375.0	37.5	-	37.5	11.1%	2.50%
35	2.720	11.15	0.00%	22.50%	612.0	-	612.0	0.00%	25.00%	680.0	-	680.0	68.0	-	68.0	11.1%	2.50%
40	3.940	16.15	0.00%	22.50%	886.5	-	886.5	0.00%	25.00%	985.0	-	985.0	98.5	-	98.5	11.1%	2.50%
45	5.160	21.15	0.00%	22.50%	1,161.0	-	1,161.0	0.00%	25.00%	1,290.0	-	1,290.0	129.0	-	129.0	11.1%	2.50%
50	6.380	26.15	0.00%	22.50%	1,435.5	-	1,435.5	0.00%	25.00%	1,595.0	-	1,595.0	159.5	-	159.5	11.1%	2.50%
55	7.600	31.15	0.00%	22.50%	1,710.0	-	1,710.0	0.23%	25.23%	1,900.0	17.5	1,917.5	190.0	17.5	207.5	12.1%	2.73%
60	8.820	36.15	0.00%	22.50%	1,984.5	-	1,984.5	1.23%	26.23%	2,205.0	108.5	2,313.5	220.5	108.5	329.0	16.6%	3.73%
65	10.040	41.15	0.29%	22.79%	2,259.0	28.8	2,287.8	2.23%	27.23%	2,510.0	223.9	2,733.9	251.0	195.0	446.0	19.5%	4.44%
70	11.260	46.15	1.54%	24.04%	2,533.5	173.1	2,706.6	3.23%	28.23%	2,815.0	363.7	3,178.7	281.5	190.6	472.1	17.4%	4.19%
75	12.480	51.15	2.79%	25.29%	2,808.0	347.8	3,155.8	4.23%	29.23%	3,120.0	527.9	3,647.9	312.0	180.0	492.0	15.6%	3.94%
80	13.700	56.15	4.04%	26.54%	3,082.5	553.1	3,635.6	5.23%	30.23%	3,425.0	716.5	4,141.5	342.5	163.4	505.9	13.9%	3.69%
85	14.920	61.15	5.29%	27.79%	3,357.0	788.9	4,145.9	6.23%	31.23%	3,730.0	929.5	4,659.5	373.0	140.6	513.6	12.4%	3.44%
90	16.140	66.15	6.54%	29.04%	3,631.5	1,055.1	4,686.6	7.23%	32.23%	4,035.0	1,166.9	5,201.9	403.5	111.8	515.3	11.0%	3.19%
95	17.360	71.15	7.79%	30.29%	3,906.0	1,351.9	5,257.9	8.23%	33.23%	4,340.0	1,428.7	5,768.7	434.0	76.8	510.8	9.7%	2.94%
100	18.580	76.15	9.04%	31.54%	4,180.5	1,679.1	5,859.6	9.23%	34.23%	4,645.0	1,714.9	6,359.9	464.5	35.8	500.3	8.5%	2.69%
105	19.800	81.15	10.29%	32.79%	4,455.0	2,038.9	6,493.9	10.23%	35.23%	4,950.0	2,025.5	6,975.5	495.0	(11.4)	483.6	7.4%	2.44%
110	21.020	86.15	11.54%	34.04%	4,729.5	2,425.1	7,154.6	11.23%	36.23%	5,255.0	2,360.5	7,615.5	525.5	(64.6)	460.9	6.4%	2.19%
115	22.240	91.15	12.79%	35.29%	5,004.0	2,843.9	7,847.9	12.23%	37.23%	5,560.0	2,719.9	8,279.9	556.0	(124.0)	432.0	5.5%	1.94%
120	23.460	96.15	14.04%	36.54%	5,278.5	3,293.1	8,571.6	13.23%	38.23%	5,865.0	3,103.7	8,968.7	586.5	(189.4)	397.1	4.6%	1.69%
125	24.680	101.15	15.29%	37.79%	5,553.0	3,772.9	9,325.9	14.23%	39.23%	6,170.0	3,511.9	9,681.9	617.0	(261.0)	356.0	3.8%	1.44%
130	25.900	106.15	16.54%	39.04%	5,827.5	4,283.1	10,110.6	15.23%	40.23%	6,475.0	3,944.5	10,419.5	647.5	(338.6)	308.9	3.1%	1.19%
135	27.120	111.15	17.79%	40.29%	6,102.0	4,823.9	10,925.9	16.23%	41.23%	6,780.0	4,401.5	11,181.5	678.0	(422.4)	255.6	2.3%	0.94%
140	28.340	116.15	19.04%	41.54%	6,376.5	5,395.1	11,771.6	17.23%	42.23%	7,085.0	4,882.9	11,967.9	708.5	(512.2)	196.3	1.7%	0.69%
145	29.560	121.15	20.29%	42.79%	6,651.0	5,996.9	12,647.9	18.23%	43.23%	7,390.0	5,388.7	12,778.7	739.0	(608.2)	130.8	1.0%	0.44%
150	30.780	126.15	21.54%	44.04%	6,925.5	6,629.2	13,554.7	19.23%	44.23%	7,695.0	5,918.9	13,613.9	769.5	(710.2)	59.3	0.4%	0.19%
155	32.000	131.15	22.79%	45.29%	7,200.0	7,291.9	14,491.9	20.23%	45.23%	8,000.0	6,473.5	14,473.5	800.0	(818.4)	(18.4)	-0.1%	-0.06%
160	33.220	136.15	24.04%	46.54%	7,474.5	7,985.2	15,459.7	21.23%	46.23%	8,305.0	7,052.5	15,357.5	830.5	(932.6)	(102.1)	-0.7%	-0.31%
165	34.440	141.15	25.00%	47.50%	7,749.0	8,610.0	16,359.0	22.23%	47.23%	8,610.0	7,655.9	16,265.9	861.0	(954.1)	(93.1)	-0.6%	-0.27%
170	35.660	146.15	25.00%	47.50%	8,023.5	8,915.0	16,938.5	23.23%	48.23%	8,915.0	8,283.7	17,198.7	891.5	(631.3)	260.2	1.5%	0.73%
175	36.880	151.15	25.00%	47.50%	8,298.0	9,220.0	17,518.0	24.23%	49.23%	9,220.0	8,935.9	18,155.9	922.0	(284.1)	637.9	3.6%	1.73%
180	38.100	156.15	25.00%	47.50%	8,572.5	9,525.0	18,097.5	25.00%	50.00%	9,525.0	9,525.0	19,050.0	952.5	-	952.5	5.3%	2.50%
185	39.320	161.15	25.00%	47.50%	8,847.0	9,830.0	18,677.0	25.00%	50.00%	9,830.0	9,830.0	19,660.0	983.0	-	983.0	5.3%	2.50%
190	40.540	166.15	25.00%	47.50%	9,121.5	10,135.0	19,256.5	25.00%	50.00%	10,135.0	10,135.0	20,270.0	1,013.5	-	1,013.5	5.3%	2.50%

Taxable value is estimated by subtracting variable costs (\$7.22/bbl) and upstream costs (\$4.058 billion) from the product of price and volume (244 mmbbls).
 Net price subtracts \$23.85/bbl (as determined by the computation for taxable value) from market price.

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*

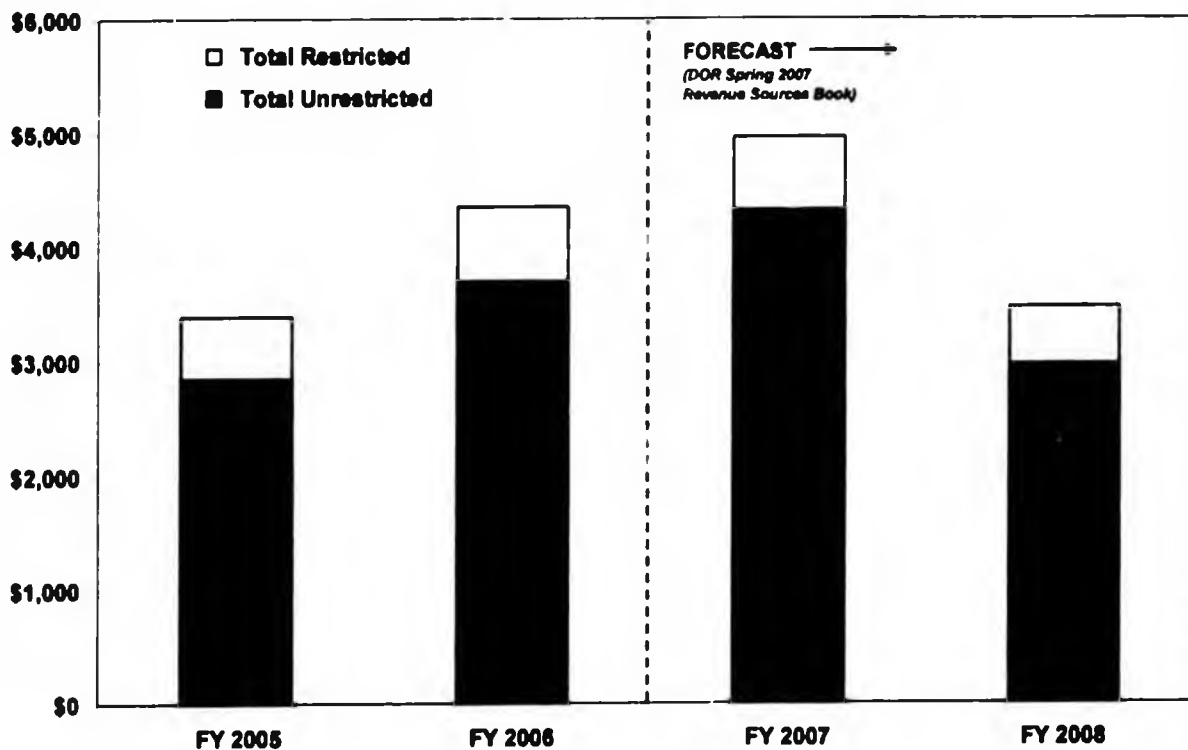
Prepared by: Jennifer Duval, Economist
jennifer.duval@alaska.gov

Date: October 23, 2007

Purpose: Request by Senator Huggins

Notes: Dollar amounts are millions of nominal dollars

Total Oil Revenue
in Millions of Dollars



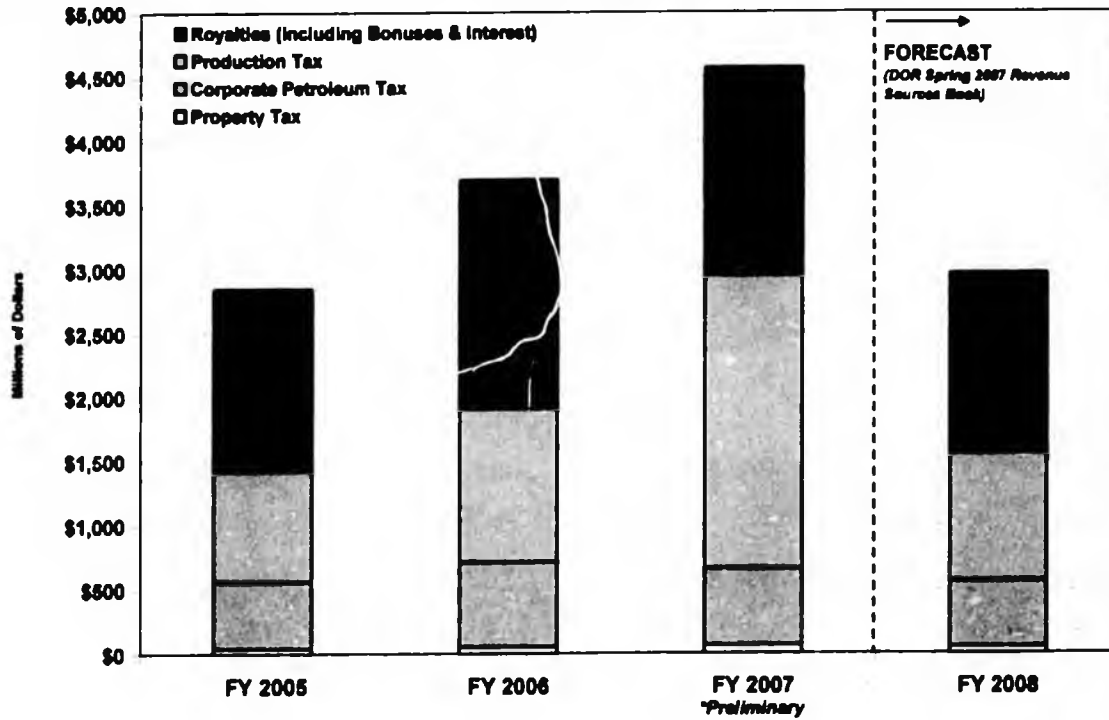
Historical and Forecast Oil Revenues FY 2005 - FY 2008

Source: DOR Spring 2007 Revenue Sources Book

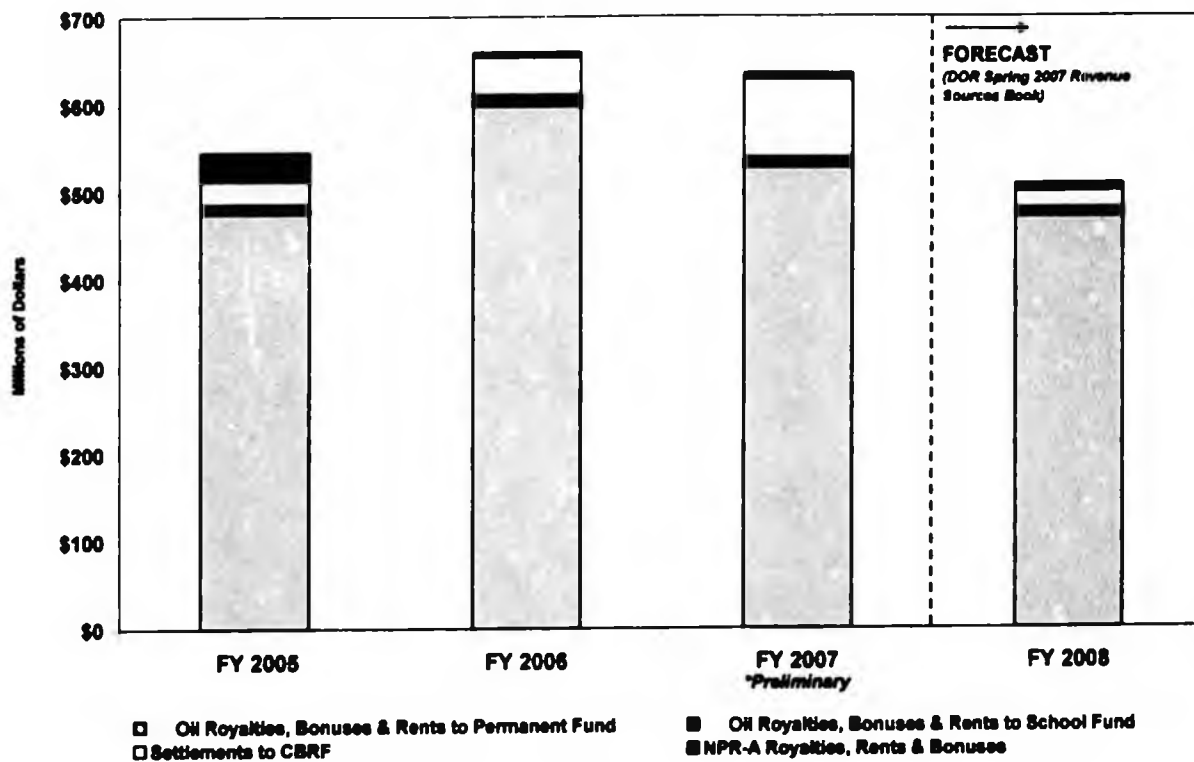
<i>In Millions of Dollars</i>	ACTUAL FY 2005	ACTUAL FY 2006	PRELIM ACTUAL FY 2007 (10/22/07)	SPR 07 FORECAST FY 2008
Unrestricted				
Property Tax	42.5	54.5	65.6	59.2
Corporate Petroleum Tax	524.0	661.1	594.4	512.1
Oil & Gas Production	854.9	1,191.7	2,282.2	983.1
Oil & Gas Hazardous Release	8.3	7.8	10.1	12.3
Production Tax	863.2	1,109.5	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	1408.4
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	478.9	599.5	535.0	471.8
Oil Royalties, Bonuses & Rents to School Fund	9.8	12	10.6	9.4
Royalties to Permanent Fund & School Fund + Bonuses & Interest	488.5	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	648.5	669.7	672.1	509.5
Total Oil	3,398.1	4,368.9	5,237.4	3,476.6

Percent of Total Oil	FY 2005	FY 2006	FY 2007	FY 2008
Property Tax	1.3%	1.3%	1.3%	1.6%
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%

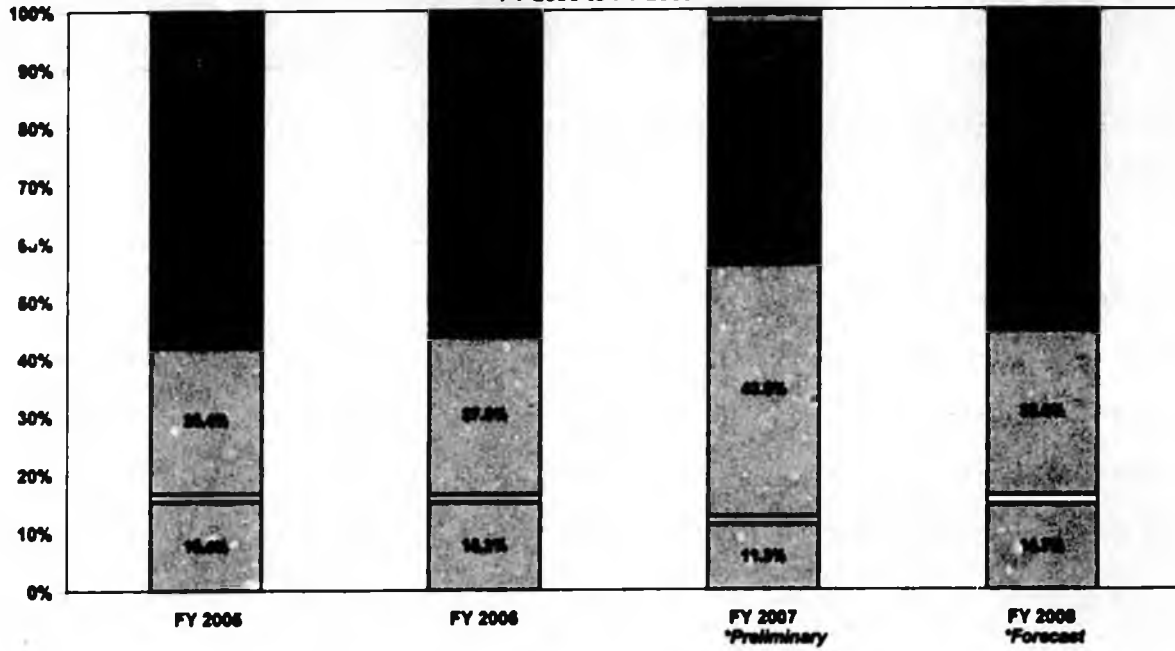
Unrestricted Oil Revenue by Category FY 2005 to FY 2008



Restricted Oil Revenue FY 2005 to FY 2008

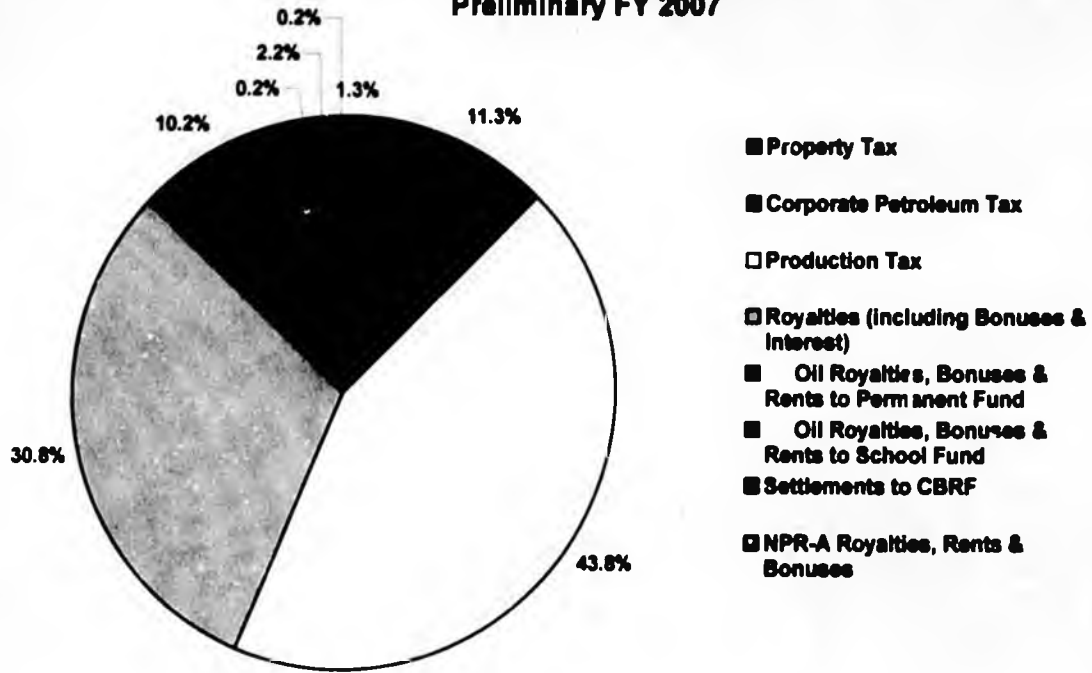


Percent Distribution of Total Oil Revenues by Year
FY 2005 to FY 2008

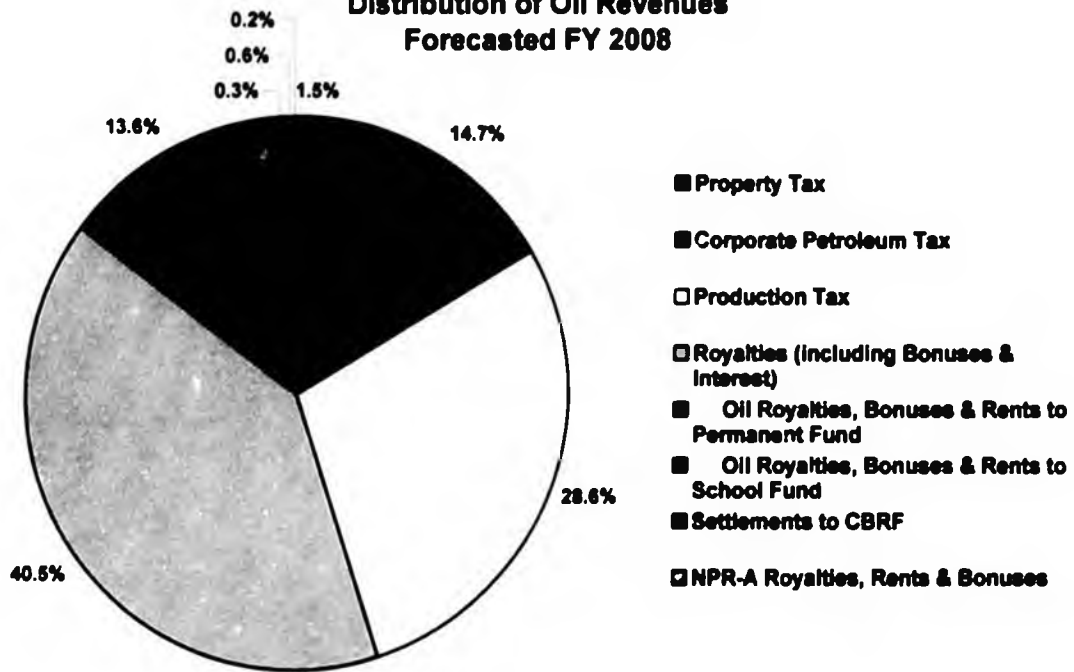


- Corporate Petroleum Tax
- Production Tax
- Oil Royalties, Bonuses & Rents to Permanent Fund
- Other Restricted
- Property Tax
- Royalties (including Bonuses & Interest)
- Settlements to CBRF

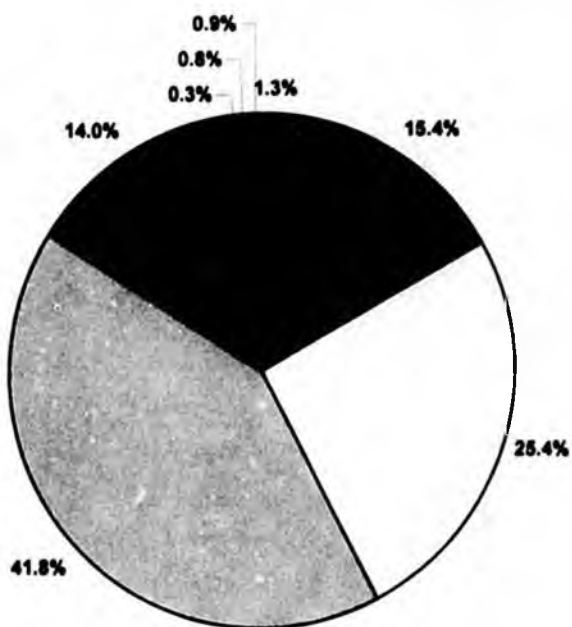
**Distribution of Oil Revenues
Preliminary FY 2007**



**Distribution of Oil Revenues
Forecasted FY 2008**

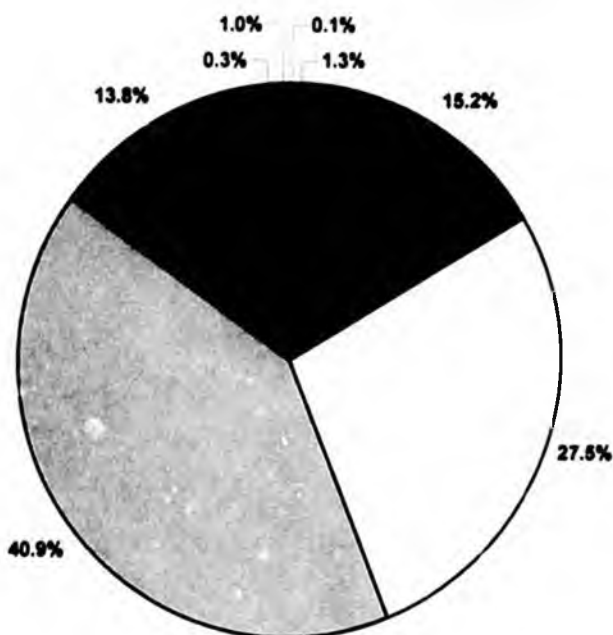


**Distribution of Oil Revenues
FY 2005**



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

**Distribution of Oil Revenues
FY 2006**



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

Tax Interest and Penalties Under ACES and Current Law

Distributed by the Department of Revenue

October 29, 2007

Under AS 43.05.220, the state may levy three types of civil penalties for failure to file a return or report or pay the full amount of tax. These include a basic penalty for underpayment or failure to file, a penalty for negligence, and a penalty for fraud. All three are general provisions applying to all state taxes, including the oil and gas production tax. Penalties are calculated as a percentage of the tax deficiency and are cumulative, so that a fraudulent taxpayer, for example, could be assessed the fraud penalty, in addition to the negligence penalty and the basic failure to file or pay penalty.

Basic Penalty

The basic failure to file penalty arises when the taxpayer fails to file a return or report when required or pay the full amount due. Five percent of the unpaid balance of the tax liability is added to a tax for each 30 day period, or fraction of the period of noncompliance. This penalty may not exceed a total of 25% of the unpaid balance. The penalty may be forgiven if the taxpayer shows that the failure to file or pay is due to reasonable cause and not willful neglect.¹

Reasonable cause is not easy to show and the burden of proof lies with the taxpayer. The taxpayer must demonstrate in writing, and under penalty of perjury, that they acted in good faith to take all reasonable steps to ensure timeliness of the filing or payment. In determining whether the taxpayer has shown that the failure was due to reasonable cause and not willful neglect, the department considers the standards imposed by the Internal Revenue Code. Circumstances that may constitute reasonable cause include, acts of God, war, other disaster that made filing or delay unavoidable, or acts by another person beyond the control of the person required to file.²

Negligence Penalty

In addition to the basic penalty, if a deficiency is due to negligence or intentional disregard of a law or regulation, the department will, in its discretion, assess a penalty of 5% of the total amount of the deficiency. The penalty is calculated based on the total deficiency, even if only a part of the deficiency is due to negligence or intentional disregard. Negligence or

¹ AS 43.05.220(a). For more detail on failure to file and failure to pay penalties, see 15 AAC 05.210.

² 15 AAC 05.200.

intentional disregard may be shown by any relevant evidence including that the taxpayer has substantially deviated from the statutes or regulations, failed to keep adequate records, exaggerated deductions, or understated income without justification.³

Fraud Penalty

If a deficiency is due to fraud, the department shall add a penalty equal to 50% of the tax due or \$500, whichever is greater. The penalty is calculated based on the total deficiency, even if only a part of the deficiency is due to fraud. To establish fraud, the department must show by clear and convincing evidence that the taxpayer understated a tax liability with the intent to evade tax. The intent to evade the tax may be shown by any relevant evidence including evidence of false explanations regarding income, false source documents, unjustified omissions or significant understatements of income, or substantial overstatement of a deduction.⁴

In addition to the three civil penalties discussed above, AS 43.05.290 provides for a number of criminal penalties for tax evasion and willful failure to comply with payment, filing, truthful accounting and information requirements, and for perjury. Along with several misdemeanors, penalties include felonies for willfully attempting to evade a tax, willfully failing to truthfully account for and pay a tax, and willfully and knowingly assisting in preparing or presenting a false return.

ACES does not propose any change to these penalties or their current application to the oil and gas production tax. ACES does, however, add penalties for failure to comply with the various information reporting requirements contained in the bill. The penalty provisions allow the department to assess against a person that fails to make the required report a penalty of not more than \$1000 per day for each day the person fails to file the document. The reason for these additional penalty provisions is to ensure compliance with reporting requirements regardless of whether there is any tax deficiency. Unlike other penalties currently available to the department, the new penalties in ACES are not calculated based on a tax deficiency. This is important because the department needs timely and complete reporting of costs, potential tax credits, etc., even from explorers and producers that may not currently owe any tax.

³ AS 43.05.220(b); 15 AAC 05.210(g). For more detail on the additional penalty for negligence or intentional disregard, see 15 AAC 05.220.

⁴ AS 43.05.220(c); 15 AAC 05.230.

Interest

The production tax currently requires monthly installment payments, in addition to annual payments and tax returns. The monthly payment is an estimate of 1/12th of the anticipated annual tax liability. The annual payment, which is accompanied by a return, requires payment of any difference between the estimated liability and actual liability during the 12 month period. The current production tax statute sets a generally lower interest rate for underpayments or overpayments of monthly installments of estimated tax due to the estimated nature of the monthly payment.

Interest on an unpaid amount of a monthly installment payment bears interest at the rate prescribed under the Internal Revenue Code, compounded daily from the date the installment is due until paid (if paid not later than when the annual return is due). That rate is currently at 8%. For corporate underpayments exceeding \$100,000, the rate increases to 10%.⁵

Overpayments of monthly installments also bear interest as stated in the Internal Revenue Code, generally at lower rates than those for underpayments. Overpayments bear interest at 8% (7% for corporations) and 5.5% for the portion of a corporate overpayment greater than \$10,000.⁶

Any portion of monthly installment payments that remains unpaid as of the annual filing date, as well as the interest accrued for those payments, is treated as a delinquent tax. Delinquent taxes are subject to a higher interest rate, currently 11% compounded quarterly.⁷

If the taxpayer has overpaid as of the annual return, the department has 90 days after the later of the date the return was filed or the due date of the return to refund the overpayment without incurring interest. After that, the state owes interest, currently 11% compounded quarterly.⁸

⁵ AS 43.55.020(g); 26 U.S.C. 6621.

⁶ AS 43.55.020(h); 26 U.S.C. 6621.

⁷ AS 43.55.020(g); 43.05.225.

⁸ AS 43.55.020(h); 43.05.225.

Capital Spending on Alaska's North Slope Wells, Field Facilities and Exploration

Millions of nominal Dollars (dollars of the day)

	BP			ARCO/ConocoPhillips			Exxon			Other			All Companies		
	Exp	Dev	Tot	Exp	Dev	Tot	Exp	Dev	Tot	Exp	Dev	Tot	Exp	Dev	Tot
1975															3,827
1976															1,106
1977															890
1978													274	400	674
1979													174	1,282	1,456
1980													178	1,804	1,780
1981													419	3,104	3,523
1982													647	3,839	4,486
1983													818	1,100	1,918
1984													258	1,193	1,451
1985													514	1,547	2,061
1986													288	771	1,059
1987													288	1,020	1,308
1988													38	765	801
1989													132	748	880
1990													98	1,081	1,157
1991		684	684		43	343		151	151				120	1,178	1,288
1992		573	573		294	294		124	124				216	991	1,207
1993		591	591		416	416		140	140				192	1,148	1,220
1994		564	564		152	152		93	93				72	808	892
1995		542	542		124	124		82	82				84	748	856
1996		551	551		188	188		87	87				108	828	922
1997		687	687		274	274		109	109				96	1,070	1,142
1998		700	700		705	705		155	155				72	1,560	1,608
1999		400	400		684	684		115	115		50	50	48	1,179	1,239
2000		670	670		725	725		150	150		100	100	80	1,545	1,697
2001	34	714	748	108	612	720		200	200	10	110	120	152	1,636	1,788
2002	9	439	448	182	434	538		172	172	15	9	24	126	1,054	1,180
2003	0	416	416	75	386	461		180	180	15	8	23	90	970	1,080
2004		412	412	35	400	435		160	160	32	8	40	87	980	1,047
2005													30	1,288	1,301
2006													123	1,591	1,714
2007													194	1,787	1,981

Sources: 1975-1989: Data from the "International Oil Tax Comparison Study", April 1990. Study did not provide a breakdown by company and no detail for the years 1975-1977.

1990-2000: BP and Arco annual reports; Communications with BP, Arco Alaska. Various published sources. A breakdown by company provided, but no breakout of exploration cost and development costs. Exploratory costs assumed to follow \$12 million dollar per well rule of thumb.

2001-2004: Communication with BP, ConocoPhillips 2002 & 2003 Annual Reports, publications/estimations for others. Breakout of capex by company & type Capex spending.

2005-2007: Unaudited taxpayer submitted EIC and PPT credit information as of 10/3/07. Exploration and development spending breakdown may contain inaccuracies, due to limited information and to the fact that costs that do not qualify for exploration credits may qualify under the PPT as development capital credits.

Definitions: Exp = Exploration, Dev. = Development spending, Tot = Explorations and development spending

Note: ARCO/Conoco Phillips exploration expenses in their Annual Reports include acquisition costs, lease rentals, and expensed overhead. BP's capex spend for 2001 and 2002 was only for capex.

State of Alaska
Department of Revenue
Commissioner's Office



SARAH PALIN, GOVERNOR
333 Willoughby Avenue, 11th Floor
P.O. Box 110400
Juneau, Alaska 99811-0405
Phone: (907) 465-2300
Fax: (907) 465-2394

To: All Members of the Legislature

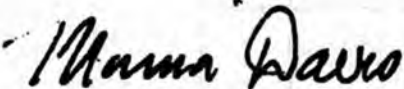
October 24, 2007

Dear Members:

I am distributing this attached document for your records entitled, *Capital Spending on North Slope Wells, Field Facilities and Exploration*. The document was compiled by the Department from publicly available data (individual company data) and tax data aggregated by the Department (All Companies data) relating to North Slope production costs.

A previous version, distributed as an attachment to a 10-17-07 letter from the Department of Revenue to Representative Doogan contained erroneous 2005 and 2006 data. Please replace any copies you may have with the attached document. We apologize for the confusion.

Sincerely,


Marcia Davis, Deputy Commissioner
Department of Revenue

State of Alaska
Department of Revenue
Commissioner's Office



SARAH PALIN, GOVERNOR
333 Willoughby Avenue, 11th Floor
P.O. Box 110400
Juneau, Alaska 99811-0405
Phone: (907) 465-2300
Fax: (907) 465-2394

To: All Legislators
From: Marcia Davis, Deputy Commissioner, DOR
Re: North Slope Production Data Request

October 23, 2007

North Slope Production

FY 2007	Thousand Bls/day
June	794
July	685
August	623
September	668
October	739
November	670
December	810
January	799
February	778
March	767
April	760
May	787
FY 2008	
June	726
July	727
August	672
September	651
October	723 (10 days est.)

State of Alaska

Department of Revenue
Commissioner's Office



SARAH PALIN, GOVERNOR

333 Willoughby Avenue, 11th Floor

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Juneau, Alaska 99811-0405

Phone: (907) 465-2300

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To: All members of the Legislature
From: Marcia Davis, Deputy Commissioner, DOR

October 25, 2007

Dear Members:

The attached memorandum was requested of Spencer Hosie by the Department of Law regarding the litigation risk and burden associated with a profits-based oil production tax. The memo provides a short history of the ANS Royalty Litigation and outlines issues the State is likely to experience in enforcing and collecting taxes under a net tax regime. I hope you will find the document useful in your coming deliberations.

Sincerely,

A handwritten signature in cursive script that reads "Marcia Davis".

Marcia Davis, *Deputy Commissioner*
Department of Revenue

MEMO

To: Department of Law, State of Alaska
From: Spencer Hosie
Subject: ANS Royalty Litigation and Gross Versus Net Tax
Date: October 17, 2007

The Department of Law has asked for a brief memo summarizing why the *ANS Royalty Litigation* took near 20 years to resolve, and whether the State may expect similarly protracted, complex litigation with a "net" severance tax, *i.e.*, a tax based on revenues net of allowable costs. As we understand it, the concern is that a net tax will inject a multiplicity of complex factual issues, thereby leading to expensive and protracted litigation.

This memo first summarizes why the *ANS Royalty Litigation* took as long as it did. It then contrasts what we believe the State should expect in enforcing and collecting taxes under a net tax regime, and how this process will differ from the civil litigation in the *ANS Royalty Litigation*. Finally, the memo concludes with several concrete examples of recent State of Alaska cases which provide reasonable benchmarks of what the State is likely to experience in enforcing a net production tax.

I. THE ANS ROYALTY LITIGATION.

The State of Alaska filed what would become the *ANS Royalty Litigation* in 1977. The oil phase of the case was resolved in 1992; the gas liquids phase settled in 1995. All-in, the case took nearly two decades to resolve. Through the litigation, the State recovered significantly in excess of \$750 million and established going-forward royalty payment rules designed to either streamline or – preferably – eliminate prospective litigation, as discussed below.

There were four principal reasons why this matter took so long and cost so much. First, the State was not acting as a sovereign in the case, but rather as a party to a commercial contract; a litigant like any other. In that context, the State did not have the authority to serve and enforce subpoenas as sovereign, select an administrative judge, or rely on regulations to expedite dispute resolution. Instead, as in any private litigation, the State had to serve and enforce discovery through the civil discovery process, which can be (and was) extremely time consuming. This is very unlike the rights that legislation and regulations provide for enforcing a production tax, as set forth below.

Second, the *ANS Royalty* case involved numerous complicated legal questions of first impression. For example, did the DL-1 lease form permit the State to assess values in downstream markets, then netted back to Pump Station 1? Did the producers owe the State any duty above those owed to a private commercial party? How is market value to be determined under ¶ 15 of the lease, and what did the tripartite "proceeds" subparagraphs of ¶ 16 mean and require? These fundamental questions of contractual interpretation¹ required years of briefing, including discovery into the origin of other states' lease forms, leading to summary judgment decisions, all of which necessarily occurred before the State built its damage models. Put simply, even the basic royalty rules were not clear and had to be established through litigation.

Third, once having established that the State had the right to look to downstream markets to assess market value, and then to net back those values to derive a Pump Station 1 royalty value, the State literally had to track *every single barrel* of ANS previously produced to its market destination. Tracking many billions of barrels to myriad Lower 48 destinations over a near-15 year period proved a byzantinely complex and daunting task, one that took the State's

¹ In addition, the producers challenged venue in Alaska, arguing that every judge and juror in Alaska had a financial stake in the outcome given the Permit Fund Dividend. This issue was resolved only after two interlocutory appeals to the United States Court of Appeals for the Ninth Circuit.

outside accounting and economic experts years to complete. As part of this process, the State then had to assess the reasonable and actual transportation deduction for every barrel transported.

Fourth, the *ANS Litigation* involved all ANS producers and all were active in the litigation, even though the case focused on Exxon, Sohio, and Arco. The State had to conduct separate discovery of each producer within the context of a single case, and this substantially delayed completion of the lawsuit.

Finally, in the *ANS Royalty Litigation*, the State necessarily approached the ANS industry as a whole, and as a matter of first impression. In the 1980s, the State did not have deep institutional knowledge of how the ANS business worked, how the producers conducted business, what transportation costs were reasonable and what not, how the producers handled common (or "joint") cost accounting, and similar issues. In contrast, the State now has significant institutional expertise, having audited ANS producers for decades.

II. WILL A NET PRODUCTION TAX SPAWN MULTIPLE ANS ROYALTY-LIKE CASES?

Tax is not royalty. In enforcing its production tax statute and regulations, the State acts as a sovereign. The Legislature has authorized a regulatory structure that gives it the right to compel document production, to set a reasonable schedule, and to proceed under the functional equivalent of an Administrative Law Judge (hearing officer). These procedural differences are substantive and real. A single taxpayer case should proceed from audit to hearing in no more than two years, as described below. Two years is a long time, but a far cry from the two decades in *ANS Royalty Litigation*.

Second, unlike the royalty context, the basic tax rules will be set forth by statute, with the disputes on the margin, e.g., wrong costs deducted, or costs inflated, etc.... In a tax context, the

basic structure and rules are a given; in the *ANS Royalty Litigation* case, these rules had to be established through hotly, contentious litigation.

Third, presumably the State will vigilantly audit ANS taxpayers under any production tax, gross or net. *Audits should be conducted on a yearly basis, and if an issue arises, it should be dealt with promptly.* The *ANS Royalty Litigation* took decades in part because it involved decades of production by the time it was resolved; this will not be the case in the tax context.

Fourth, given taxpayer confidentiality, and the nature of the tax audit process, any tax proceeding would be taxpayer-specific. A single taxpayer proceeding should move much faster than a multi-party case such as the *ANS Royalty Litigation*.

Finally, and as noted above, the State now has deep institutional knowledge concerning the ANS business, including market values and transportation costs. This knowledge comes from the *ANS Royalty Litigation* itself, plus several follow-on cases (described below), and numerous tax audits and cases. The State now has accumulated decades of experience in auditing production and transportation costs, as well as a group of outside expert consultants who are well-versed in these matters.

To be clear, all else equal, a net tax will be more complex to administer and enforce than a gross tax. If the past is any guide, the taxpayers may well game costs, e.g., suddenly allocating an inappropriately large percentage of joint or common costs to their Alaska business. But the additional complexity should be manageable, and the State can discourage overly creative cost accounting by vigilantly auditing and enforcing the statute and regulations from the outset.

III. ROYALTY "REOPENER" CASES: A TAX PARADIGM.

The State recently had several "reopener" cases which serve as useful examples for what might be expected under a net production tax.

As part of the *ANS Royalty Litigation* settlement, the State and each of several producers agreed to formulas for future royalty payments, along with a short-fuse dispute resolution mechanism. That mechanism includes limited discovery, short deadlines, and a three-judge arbitration panel empowered to make a binding decision. If either party grows dissatisfied with the operation of the agreed royalty formula, it has the right (in certain general circumstances) to trigger a "reopener," which serves to start the dispute resolution process.

The State has had several such *ANS Royalty Litigation* "reopener" proceedings. Each has involved limited and manageable discovery, a relatively quick path to hearing, and a binding decision or settlement promptly after the arbitration hearing begun. On average, these matters have taken 20 to 22 months of active litigation, despite involving complex cost and revenue issues (and zealous producer counsel). For example, in the first of several reopeners, outside counsel became involved in August 2003, trial was in April 2005, a binding decision in the State's favor received in June 2005, and the State was paid promptly thereafter.

As noted, these "reopeners" are good models for what to expect under a net tax, as both involve: (1) established rules (by statute in tax); (2) streamlined administrative process; (3) company specific proceedings; and, (4) proceedings that benefit from State's historical, institutional knowledge.

Alternative Tax Credits for Oil and Gas Exploration

ACES Amendments to AS 43.55.025

**Kurt Gibson
Julie Houle
Division of Oil and Gas**

October 31, 2007



Alaska Department of

**NATURAL
RESOURCES**

Division of Oil and Gas



- Before PPT, DOR offered credits for exploration wells and seismic surveys
 - AS 43.55.025 - Alternative tax credit for oil and gas exploration
- ACES original language intended to do the following
 - Provide additional predictability to explorers by establishing a pre-approval process
 - Shore up data sharing requirements

Broaden existing program



- Creates new 5% credits for old seismic surveys if the DNR commissioner determines that the acquisition is in the best interest of the state
- Extends the timeline allowed to drill wells from 150 to 540 days

Enhances Predictability



Pre-approval process identifies up front whether or not activity qualifies for tax credit

- More fair to investors to inform them (going forward) whether or not they are credit eligible
- Predictability reduces the state's exposure to litigation by stripping out uncertainty
- Prudent practice for the state as a "working interest" owner to make forward looking investment decisions

Data Sharing



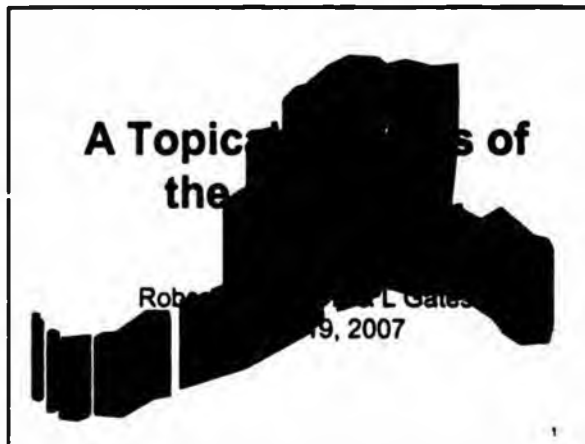
State has a right to certain data stemming from its decision to invest in project

- Seismic**
- Well data**
- Fluid data**
- Core data**

New language provides clarity and consistency in what data must be shared

These data sharing requirements are consistent with those of other jurisdictions

By shoring up the data sharing language the state preserves its ability to pursue long-range exploration incentive goals



A Few Background Basics:
The oil and gas production tax . . .

- is in AS 43.55
- is in addition to royalties, property tax, and income tax
- has existed since before statehood
- generally applies a percentage tax rate to the *value* of oil and gas produced
- unlike royalties, applies to production from private and federal leases as well as state leases

2

**Core Provisions of HB 3001
(enacted in 2006)**

- AS 43.55.011(e) – (l): tax levied on value of oil and gas produced
- AS 43.55.160: calculation of taxable value of oil and gas
- AS 43.55.165 & .170: determination of upstream costs that may be deducted in calculating taxable value of oil and gas

(cont.)

3

Core Provisions (continued)

- AS 43.55.023 & 43.55.024: new tax credits
- AS 43.55.020(a): monthly estimated tax payments and final payment on March 31 of year following production (because this is now an annual, not a monthly, tax)
- AS 43.55.030(a): just one annual return

4

AS 43.55.011(e) (current)

- There is levied on the producer . . . a tax for all oil and gas produced . . . equal to 22.5 percent of the production tax value of the taxable oil and gas as calculated under AS 43.55.160 . . .
- Note: “production tax value” is net value

5

AS 43.55.011(e) (continued)

Exceptions:

- Tax does *not* apply to
 - state or federal share
 - landowner’s royalty share (which is subject to a different tax provision)
- Cook Inlet production subject to ceilings based on past taxes (AS 43.55.011(j) & (k))
- North Slope production subject to a minimum tax depending on price of ANS (AS 43.55.011(f))

6

AS 43.55.011(g) (current)

- For each month when the net value of a producer's oil and gas exceeds \$40 per barrel, the tax rate under subsec. (e) is in effect increased by 1/4 of a percentage point for each dollar per barrel over \$40
- Informally known as "progressivity tax"
- Gas and oil are added together by treating 6 million Btu of gas as equivalent to one barrel of oil (see AS 43.55.011(h), 43.55.900(17), (18) & (24))

progressivity # is a net #

**AS 43.55.011(e) (new)
Bill sec. 15**

- There is levied on the producer . . . a tax for all oil and gas produced . . . equal to the production tax value of the taxable oil and gas as calculated under AS 43.55.160 multiplied by the tax rate determined under (g) of this section.

**AS 43.55.011(g) and (h) (new)
Bill secs. 17 and 18**

- "The tax rate . . . is 25 percent plus" the progressivity tax rate
- The progressivity tax rate is 1/5 of a percentage point for each dollar per barrel over \$30 net value
- Progressivity is calculated on an annual, not monthly, basis

**North Slope Tax Floor
Bill sec. 16**

- New AS 43.55.011(f): minimum tax is 10 percent of gross value at the point of production of oil and gas from a unit (or nonunitized reservoir) that
- (1) has produced a cumulative total of 1 billion barrels; and
- (2) is producing over 100,000 barrels a day (average during the most recent calendar year)

applies to legacy fields

**Cook Inlet Tax Ceilings
Bill secs. 19 and 20**

- Tax ceilings are not changed (conforming amendments only)
- Note: sec. 21 of the bill adds language dealing with Cook Inlet tax credits to be consistent with sec. 55, which clarifies how excess lease expenditures are treated

AS 43.55.160 (bill secs. 52-55)

- The basic principle is unchanged: taxable value = gross value at the point of production minus lease expenditures
- Wording has been changed:
- (1) monthly values are no longer needed (progressivity is now annual)

govt bill not RRS bill

Marsha Davis - 10-29-2007

Hypothetical example

net tax -

say tax rate = 20%

spend \$100 minus 20% (\$20) = cap. invest. of \$80
state spent \$20

① deduct in net tax

② + get it as capital credit

Higher tax rate = higher net present value to producers

" " "

= more of an incentive for new
developments (but doesn't enhance
state revenue as much progressivity)

AS 43.55.160 (cont.)

- (2) bill is clearer and more specific on when a producer may or may not use lease expenditures for operations at one location as deductions for oil and gas produced at another location
- These rules are necessary to implement the different tax treatments of different areas and fields (Cook Inlet ceilings, North Slope floor, tax credit under AS 43.55.024(a))

13

AS 43.55.160 (cont.)

- For instance:
- (i) To avoid undercutting the tax floor, deductions may not be "exported" from units subject to the tax floor (AS 43.55.160(f)(2))
- (ii) To avoid double-dipping re: Cook Inlet tax ceilings, deductions must first be used up in Cook Inlet and may not be shielded by the ceilings (AS 43.55.160(h) and (i))

14

AS 43.55.165 (bill secs. 56-59, 64) Lease Expenditures

AS 43.55.165(a) and (b) are rewritten and reorganized:

- (1) for more clarity
- (2) to limit lease expenditures to only what the Department of Revenue allows by regulation

15

Lease Expenditures (continued)

- AS 43.55.165(c) and (d) are repealed.
- Those provisions allowed the Department to substitute cost billings under unit operating agreements in place of the general standards for determining lease expenditures.

16

Lease Expenditures (continued)

- AS 43.55.165(e): the list of *excluded* costs is expanded:
- par. (7) – costs arising from violation of law or noncompliance with lease or permit obligation
- par. (8) – all dismantlement, removal, & restoration costs (costs are prorated for past production under current law)

17

Lease Expenditures Exclusions (cont.)

- par. (19) - repair or replacement of facilities or equipment associated with an unscheduled drop in production or an oil spill or unpermitted release
- par. (20) – crude oil topping plant (but deduction is allowed for value added of product used in lease operations)

18

**Tax Credits under AS 43.55.023
Bill secs. 26-31, 65**

Changes to .023(a) – qualified capital investment expenditure credits :

- Only 50% of a credit may be used the first year
- For exploration, requirements are conformed to changes in .025 credits (see below)

18

**Tax Credits under AS 43.55.023
(continued)**

Changes to .023(a) (continued)

- Credits for capital expenditures in a unit subject to the tax floor may be applied only against tax on oil and gas production from that or another unit subject to the tax floor

19

**Tax Credits under AS 43.55.023
(continued)**

Change to .023(b) – carried-forward annual loss credit :

- No carry-forward for unused lease expenditures for units subject to the tax floor

21

**Tax Credits under AS 43.55.023
(continued)**

Change to .023(d) – transferable tax credit certificates:

- Two certificates will be issued, each for half of the credit
- One certificate cannot be used until the next year

22

**Tax Credits under AS 43.55.023
(continued)**

New subsection .023(l) :

- Makes clear that a tax-exempt entity may not obtain a transferable tax credit certificate

23

**Tax Credits under AS 43.55.023
(continued)**

AS 43.55.023(i) is repealed:

- This eliminates the transitional investment expenditure credits for investments that were made during the five years before April 1, 2006.

24

**Tax Credits under AS 43.55.025
Bill secs. 36-44**

- Sec. 36 - Existing 2016 sunset is uniformly applied
- Secs. 37 & 43 - Exploration well credit expanded to delineation wells within 2 drilling seasons (rather than being limited to discovery well or dry hole)
- Sec. 37 - Well must be completed or abandoned, not just suspended, before credit may be claimed

25

**Tax Credits under AS 43.55.025
(continued)**

- Sec. 37 - Costs excluded if due to gross negligence or health/safety/environmental violation
- Sec. 38 - Clearer definition of requirement for new exploration target; 3-mile requirement deleted for Cook Inlet; DNR evaluation required in advance and after drilling

26

**Tax Credits under AS 43.55.025
(continued)**

- Sec. 39 - Data submission requirements are more specific
- Sec. 39 - Well data confidentiality limited to 24 months
- Sec. 39 - Two certificates will be issued, each for half of the credit; one certificate cannot be used until the next year

27

**Tax Credits under AS 43.55.025
(continued)**

- Sec. 39 - Makes clear that basic information about tax credit is public
- Sec. 40 - Makes clear that a tax-exempt entity may not transfer a tax credit certificate
- Sec. 44 - New five percent tax credit available for old seismic data if DNR determines that acquiring the data for public distribution is in state's interest

28

**State Purchase of Tax Credits
Certificates - Bill secs. 45 & 63**

- New AS 43.55.028 establishes oil and gas tax credit fund to purchase credit certificates from explorers or small producers that have no tax liability to apply credits against
- Funded by appropriation of a percentage of production tax revenues
- Replaces existing cash refund authority under AS 43.55.023(f) (repealed by bill)

29

**State Purchase of Tax Credits
Certificates (continued)**

- Retains existing criteria for refunds except eliminates \$25 million maximum

30

**Payment of the Tax
Bill secs. 22-25, 51**

- Current system of monthly installment payments and final payment on March 31 is retained
- Installment payments now take account of the tax floor for units subject to the tax floor and also take account of Cook Inlet tax ceilings
- Installment payments do not take account of progressivity rate

31

**Payment of the Tax
(continued)**

- AS 43.55.110(f), Bill sec. 51 – Gives express authority to Department to require tax payments to be made electronically

32

**Reporting Requirements
AS 43.55.030, 43.55.040**

- Bill sec. 46 – Makes clear that every oil or gas producer must file an annual return, whether or not tax is due
- Bill sec. 46 - Expands the list of specific information requirements for returns (note: Department retains general authority to require more information)

33

**Reporting Requirements
(continued)**

- Bill secs. 47 & 49 – Additional penalty of up to \$1,000 per day for late filing or nonfiling of required returns or reports
- Bill sec. 48 – Requires explorers or producers to file an annual statement on expenditures (or adjustments) even if no oil or gas is produced during the year

34

**Reporting Requirements
(continued)**

- Bill sec. 48 – Makes clear that the Department may also require monthly reports from producers, explorers, and operators
- Bill sec. 49 – Adds express authority for the Department to require reporting of forward-looking information for revenue forecasting purposes

35

**Reporting Requirements
(continued): Bill sec. 51**

- AS 43.55.110(e) – Gives express authority to Department to require returns and reports to be filed electronically

36

Confidential and Public Information

- AS 38.05.035, Bill sec. 2 – broad authority for DNR to share oil and gas lease related information with DOR for purposes of administering the production tax
- AS 43.05.230, Bill sec. 14 – broad authority for DOR to share production tax related information with DNR

37

Confidential and Public Information (continued)

- Under both provisions, confidential information is still confidential
- AS 43.55.890, Bill sec. 61 – Makes clear that Department of Revenue may publish extensive production tax information aggregated among at least three producers or explorers

38

Additional Administrative Improvements

- AS 39.25.110, Bill sec. 10 – oil and gas auditors placed in exempt service
- Transition provision, Bill sec. 67 – current employees may opt to stay in union
- AS 43.05.260, 43.55.075, Bill secs. 14, 50 – statute of limitations for production tax is six years, not three years

39

Additional Administrative Improvements (continued)

- AS 43.55.075(b), Bill secs. 1, 50 - Legislative confirmation of Department of Revenue's interpretation of statute of limitations as applied to events that retroactively change amount of production tax or credit: period of limitations begins to run when a return is filed reflecting the change

40

Additional Administrative Improvements (continued)

- AS 43.55.110(g), Bill sec. 51 – Gives express authority to the Department of Revenue to issue advisory bulletins interpreting production tax statute and regulations for guidance of taxpayers and others; non-binding unless Department provides otherwise

41

Transition, Applicability, and Effective Dates

- Bill secs. 66, 72 – Most substantive changes in the production tax are prospective beginning Jan. 1, 2008
- Bill secs. 66, 71 – Changes to lease expenditure exclusions and use of unit operating agreements for lease expenditures are retroactive to April 1, 2008

42

**Transition, Applicability, and
Effective Dates (continued)**

- **Bill secs. 66, 71 – Statute of limitations extension applies to still-open periods and retroactive to April 1, 2006**
- **Bill secs. 66, 71 – Clarification that tax-exempt entities may not transfer tax credits applies back to beginning of the respective tax credit provisions**

43

**Transition, Applicability, and
Effective Dates (continued)**

- **Bill sec. 73 – Most other provisions of the bill take effect immediately**
- **Bill secs. 68, 70 – DOR and DNR may start developing regulations immediately, and regulations may be retroactive to applicability date of the statutory provisions they implement**

44

Oil and Gas Reporting and Disclosure In Selected Countries

Focus On Cost / Field Detail Reporting

Summary

- **In the vast majority of regimes around the world companies are required to disclose detailed data**
 - Prospective (plans) and actual
 - Typically down to well / field level detail
- **Data is provided to both resource-management and fiscal/taxation authorities**
 - Intra-governmental sharing
 - Greater flow to, rather than from, fiscal authorities
- **Reporting and public disclosure are two separate issues**
 - Public reporting is common
 - Though typically in aggregated or summary form

Why Does Alaska Need To Receive Data ?

- **Required in order to properly manage the State's resources**
 - "The energy resources of this State belong to the people of Alaska¹"
- **Full understanding of technical and commercial factors**
- **Ability to plan and control**
 - Exploitation policy
 - Budget
- **These are universal principles**
 - Not unique to Alaska

¹ Adapted from Accountability principle of Alberta Royalty Review Panel

Forms Of Reporting and Sharing

- **Production and well data**
 - Monthly or as completed

- **Annual or Semi-Annual field-level information**
 - Typically collected by Ministry / Regulatory Body

- **Tax returns**
 - Collected by fiscal authority

- **Intra-Governmental Sharing**
 - Degree of sharing varies by country
 - Typically greater sharing by Ministry / Regulatory Body than by fiscal authority

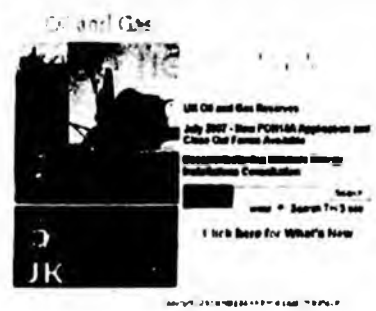
Public Reporting

- **Mostly in aggregated / summary form**
- **Some countries provide field-level summaries**
 - Reserves
 - Capex
 - More often as total, but sometimes as annual time series
- **Opex rarely disclosed at field-level, although subscription services do provide this**
 - Data quality dependent upon various sources, including “oil company guidance”
 - Sometimes occurs in stock market documentation released by (usually) smaller companies

Examples Of Data Disclosure (Production and Cost Focus)

UK Summary

- **UK requires data disclosure at field level**
 - Field development plans
 - Annual (and semi-annual) data / statistical analysis
 - PRT returns
- **Disclosure to**
 - DTI (Oil & Gas Directorate)
 - Fiscal authorities
- **Publication of aggregated information**



United Kingdom

Annual UKCS Income and Expenditure summarized on an annual basis

Income from and Expenditure on UK Continental Shelf Exploration, Development and Operating Activities
(£ million)

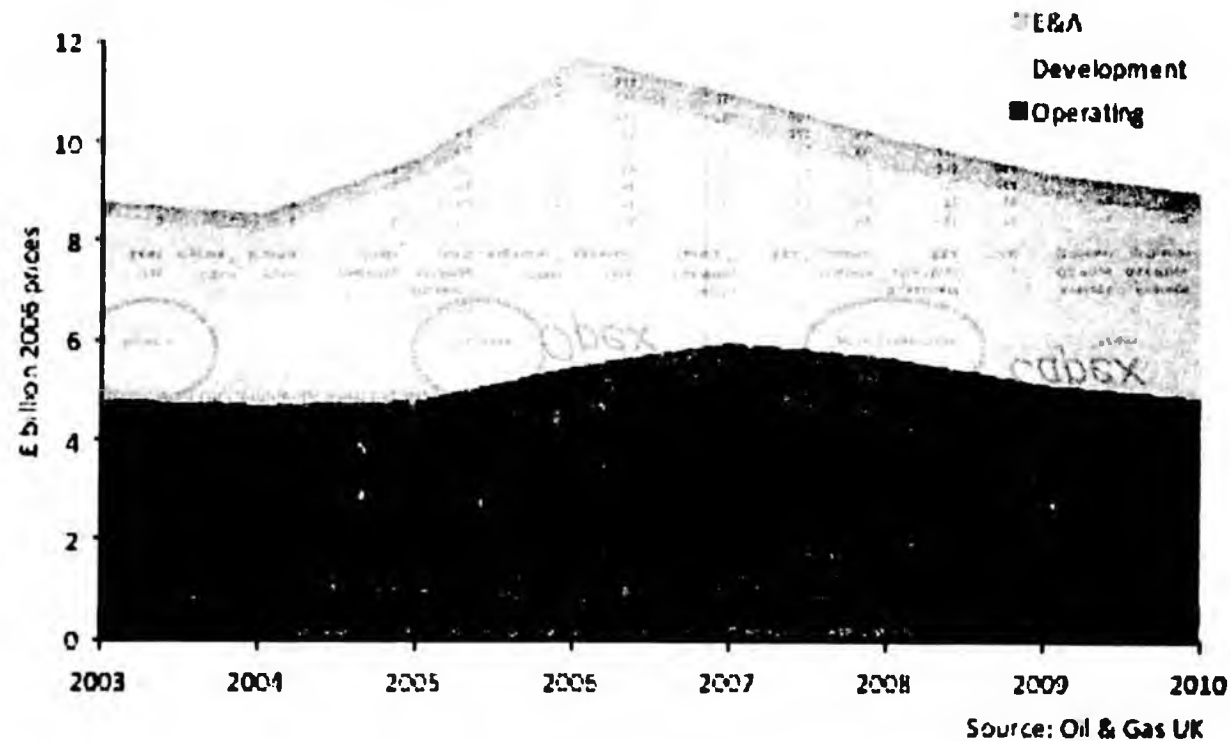
	Sales				Total Income	Opex			Gross Operating Surplus ²	Capex			Average Oil Price (\$/barrel)	Average Gas Price (\$/barrel)	QOP Operator (\$/000-1000)	
	Oil Sales	NGL Sales	Gas Sales	Other Income ¹		Operating Costs	Other ³	Total Expenses		£/A ⁴	of which: seismic	other than £/A				Total
970	0	0	3	4	6	6	48	0	-3	23	0	83	70	0	0	
971	0	0	83	8	91	11	48	0	11	78	0	72	180	0	-8	
972	0	0	114	8	122	16	48	0	16	110	0	112	164	0	11	
973	0	3	133	11	147	18	48	0	18	129	0	118	204	0	12	
974	0	3	166	21	190	20	48	0	20	170	0	149	287	0	14	
975	41	16	193	28	278	44	48	0	40	231	242	1,374	1,918	0	18	
976	624	21	218	21	924	132	48	0	180	784	101	2,070	2,872	0	21	
977	2,197	29	317	23	2,666	297	48	0	367	2,300	178	2,077	3,482	0	21	
978	2,771	38	432	12	3,253	348	48	0	396	2,855	281	2,172	3,481	0	21	
979	8,641	83	1,138	44	10,006	1,022	48	0	1,070	8,936	241	2,204	3,980	0	26	
980	8,719	132	1,447	92	10,390	1,022	48	0	1,070	9,320	270	2,388	3,707	0	26	
981	12,264	196	1,643	114	14,217	1,317	48	0	1,365	12,852	315	2,647	4,307	0	28	
982	14,125	312	1,958	182	16,577	1,338	48	0	1,386	15,191	378	3,025	4,894	0	29	
983	16,486	521	2,117	188	19,312	1,496	48	0	1,544	17,768	433	3,482	5,350	0	30	
984	19,827	869	2,393	268	23,457	1,733	48	0	1,781	21,676	506	3,189	4,694	0	30	
985	19,264	692	2,739	354	23,049	2,248	48	0	2,296	20,753	648	2,784	4,209	0	31	
986	8,869	396	827	488	10,580	2,144	48	0	2,192	8,388	478	2,419	3,447	0	32	
987	8,813	388	1,192	633	10,826	2,137	44	0	2,181	8,645	600	2,644	3,448	0	32	
988	7,344	248	2,248	888	10,728	2,388	48	0	2,436	8,292	718	3,126	3,266	0	33	
989	7,214	272	2,187	847	10,520	2,333	48	0	2,381	8,137	1,022	2,838	3,017	0	33	
990	8,421	277	2,177	426	11,301	2,882	48	0	2,930	8,371	1,027	3,478	3,114	0	33	
991	7,878	388	2,988	476	11,730	3,286	48	0	3,334	8,396	1,008	3,101	3,047	0	33	
992	7,430	383	3,016	626	11,455	3,312	48	0	3,360	8,095	1,008	3,428	3,084	0	33	
993	8,110	523	3,188	689	12,500	3,881	47	0	3,928	8,572	1,211	4,001	3,274	0	33	
994	1,014	529	3,131	874	14,802	3,882	48	0	3,930	10,872	1,211	3,671	4,000	0	33	
995	9,881	614	4,161	166	14,822	3,873	48	0	3,921	11,902	1,081	4,100	4,408	0	34	
996	1,000	748	4,288	243	16,300	3,878	48	0	3,926	18,377	1,087	4,264	4,401	0	34	
997	10,327	733	6,284	1,279	17,623	4,182	48	0	4,230	19,397	1,184	4,283	4,407	0	34	
998	7,487	881	6,313	1,483	16,164	4,182	48	0	4,230	18,931	762	4,090	4,708	0	34	
999	10,269	727	6,231	1,434	17,661	4,249	48	0	4,297	19,368	86	3,683	4,080	0	34	
2000	16,278	1,111	6,828	488	24,705	4,382	48	100	4,482	21,223	348	2,780	3,000	138.1	16.8	34
2001	12,644	863	8,143	438	24,188	4,347	48	49	4,396	19,792	423	3,070	3,000	128.7	19.3	34
2002	13,629	134	8,189	387	24,339	4,596	48	48	4,644	19,693	389	3,098	3,000	128.8	16.4	34
2003	18,348	1,126	7,884	1,039	28,397	4,486	48	8	4,534	19,863	324	3,412	3,700	132.3	17.4	34
2004	13,477	1,288	7,443	178	22,386	4,884	48	87	4,971	18,415	395	3,782	3,000	134.3	21.3	34
2005	16,864	1,484	8,822	481	27,651	5,113	47	138	5,251	23,402	483	4,371	4,000	218.8	27.6	34

Notes:
 (1) Revenues from oil and gas sales, and other revenues of operators and production licensees
 (2) Cost of oil and gas production, and production licensees not attributable to oil and gas sales
 (3) Gross Operating Surplus = Total Income less Total Expenses
 (4) £/A costs include exploration and the cost of appraisal wells drilled prior to development activity
 The figures each, to change in stocks and cost of sales

United Kingdom

Medium-term forecasts derived from annual returns

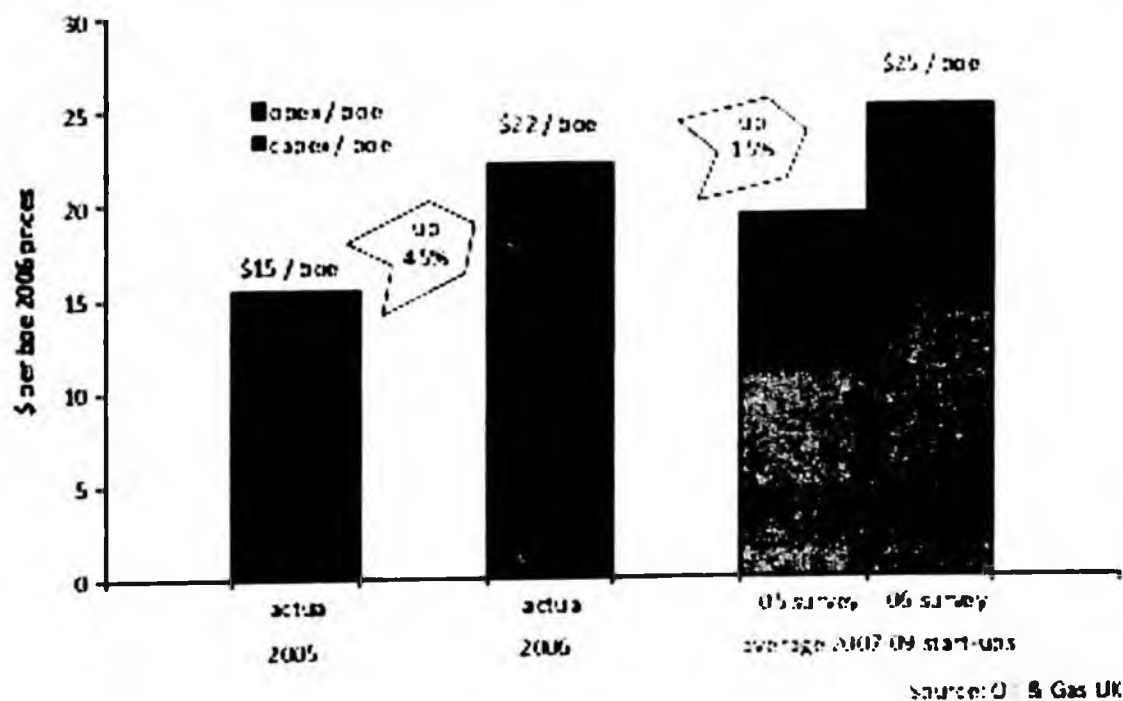
Figure 30: UKCS Expenditure Forecast 2003-2010



United Kingdom

Cost trends

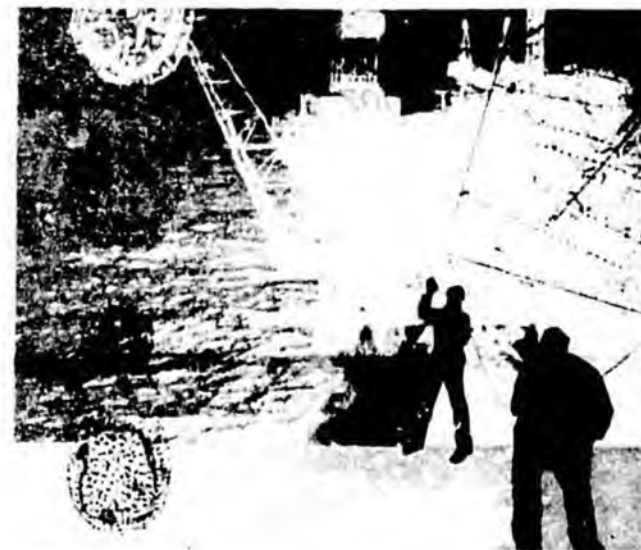
Figure 33: UKCS New Developments' Unit Technical Cost 2005-2009



Norway Summary

- **Norway requires data disclosure at field level**
 - Field development plans
 - Annual data / statistical analysis
 - Tax returns
- **Disclosure to**
 - NPD (Norwegian Petroleum Directorate) / Ministry
 - Fiscal authorities
- **Publication of aggregated information**

FACTS
THE NORWEGIAN PETROLEUM SECTOR
2007



Norway

Field / discovery listing of resource volumes

Tilstedeværende ressursar i felt
In-place resources in fields

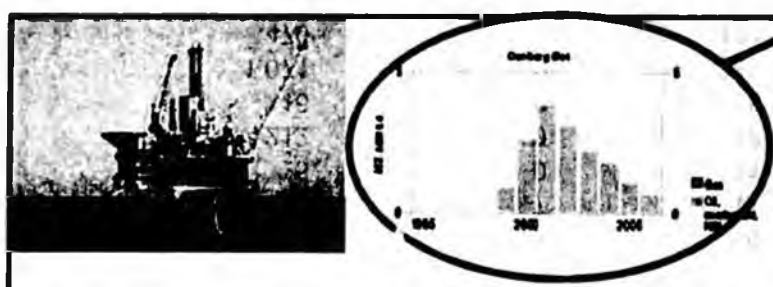


OLJEDIREKTORATET

Felt	Olje mill Sm ³ Oil million Sm ³	Assosiert væske NGL/Kondensat mill Sm ³ Associated liquids million Sm ³	Assosiert gas mrd Sm ³ Associated gas (billion Sm ³)	Fri gas mrd Sm ³ Free gas billion Sm ³
ALBUSKJELL	36	0	56	0
ALVHEIM	81	0	8	9
BALDER	137	0	7	0
BLANE	3	0	0	0
BRAGE	137	7	11	3
COD	5	0	11	0
DRAUGEN	212	0	12	0
EDDA	16	0	5	0
EKOFISK	1,071	0	286	0
ELDFISK	470	0	124	0
EMBLA	43	0	15	0
ENOCH	2	0	0	0
FRAM	58	0	8	8
FRIGG	0	1	0	150
FRØY	35	0	8	0
GIMLE	8	0	0	0
GLITNE	24	0	1	0
GRANE	209	0	3	0
GULLFAKS	583	0	69	0
GULLFAKS SØR	154	43	36	118

Norway

Detail on field-by-field basis



Production forecast by year

Reserves and EUR

Oseberg Øst

Field and production history	See the production section on page 10	
Discovered	1983	
Discovered reserves of	11.5B bbl by the E&P Council	
On 10/01/07	11.5B bbl	
Operator	Equinor	
Partners	Equinor 40.00%	
	Shell 20.00%	
	Statoil 20.00%	
	ConocoPhillips 20.00%	
	Other 0.00%	
Reserve life (years)	27.8 million bbl	11.7 million bbl
	11.5 million bbl	11.5 million bbl
Production	1.8 B bbl	1.8 B bbl
Reserves at	11.5 B bbl	11.5 B bbl
Expected production	1.8 B bbl	1.8 B bbl
2007-2012	1.8 B bbl	1.8 B bbl
2013-2027	1.8 B bbl	1.8 B bbl
2028-2037	1.8 B bbl	1.8 B bbl
2038-2047	1.8 B bbl	1.8 B bbl
2048-2057	1.8 B bbl	1.8 B bbl
2058-2067	1.8 B bbl	1.8 B bbl
2068-2077	1.8 B bbl	1.8 B bbl
2078-2087	1.8 B bbl	1.8 B bbl
2088-2097	1.8 B bbl	1.8 B bbl
2100	1.8 B bbl	1.8 B bbl

Total capital investment - historical - expected ultimate

Development
Oseberg Øst is an oil field located east of Oseberg in the northern part of the North Sea. The field has been developed with an integrated fixed facility with accommodation of all its operations and first stage separation of oil, water and gas. The well depth in the area is 140 meters.

Reservoir
The main reservoir consists of two structures separated by a sealing fault. The reservoir contains several oil-bearing layers of varying thickness and is situated within the Middle Jurassic interval.

Reservoir geology
The field is produced with reservoir management using both water injection and WAG under alternating gas injection.

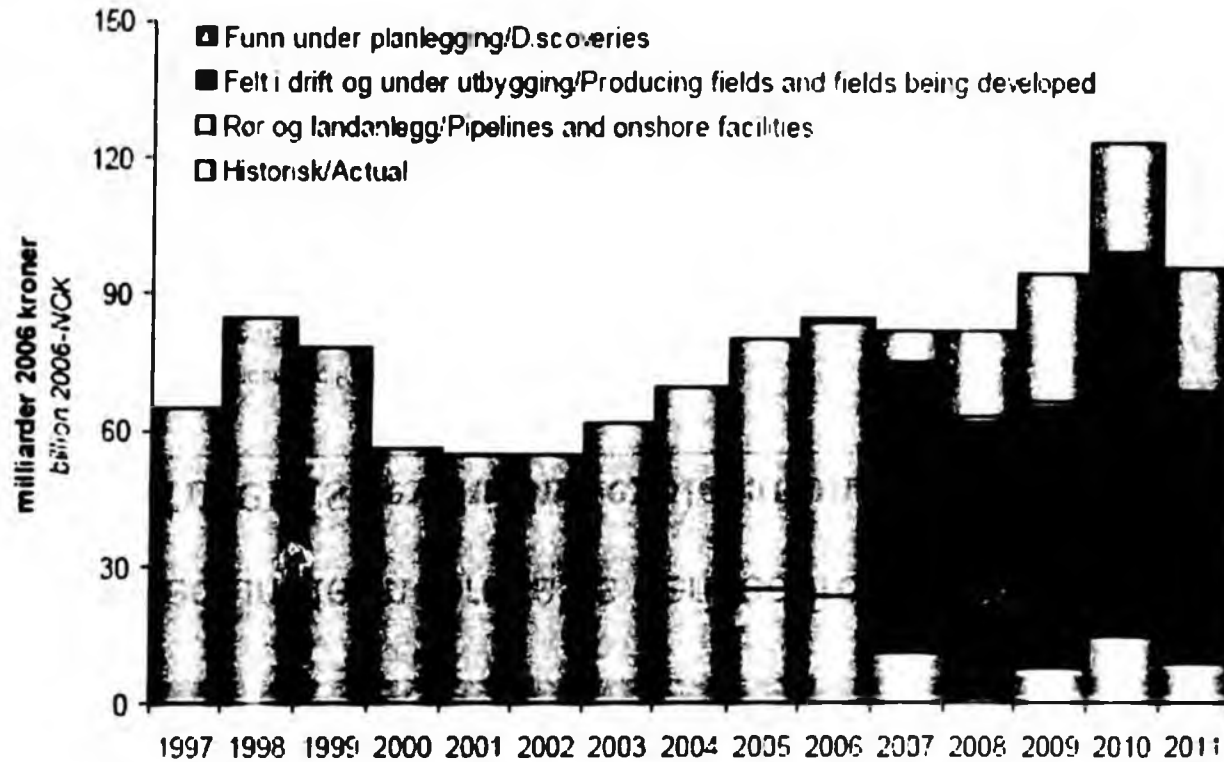
Transport
The oil is sent by pipeline to the Oseberg Processing Center for further processing and transport through the Oseberg Transport System (OTS) to the Svinne terminal. The gas is mainly used for injection, gas lift and fuel.

Status
Various reserves have been and will continue to be evaluated as ongoing projects. A new drilling campaign is expected to yield increased production. The first well in the new drilling campaign is planned to be an oil well in February 2008.

Norway

Medium-term forecasts derived from annual returns

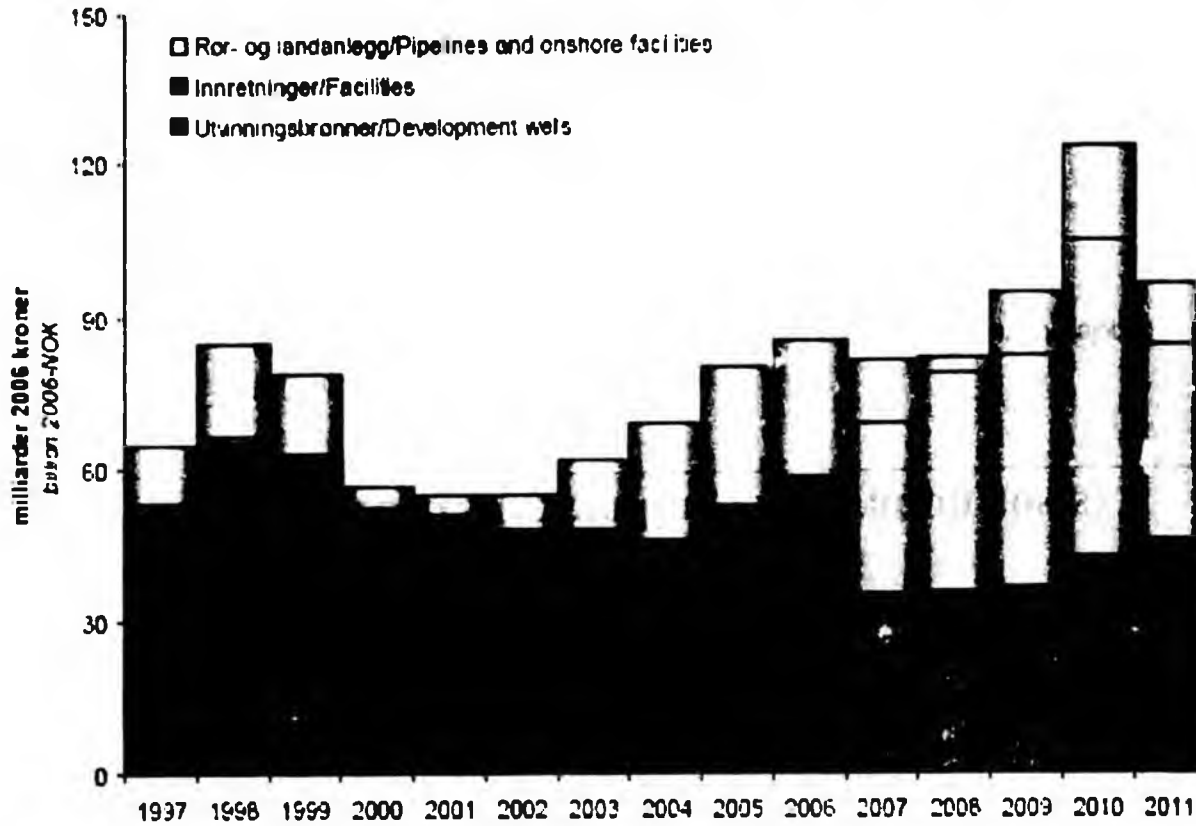
Investments (excluding exploration costs)



Norway

Medium-term forecasts derived from annual returns

Investments (excluding exploration costs)



Norway

Source of Investment

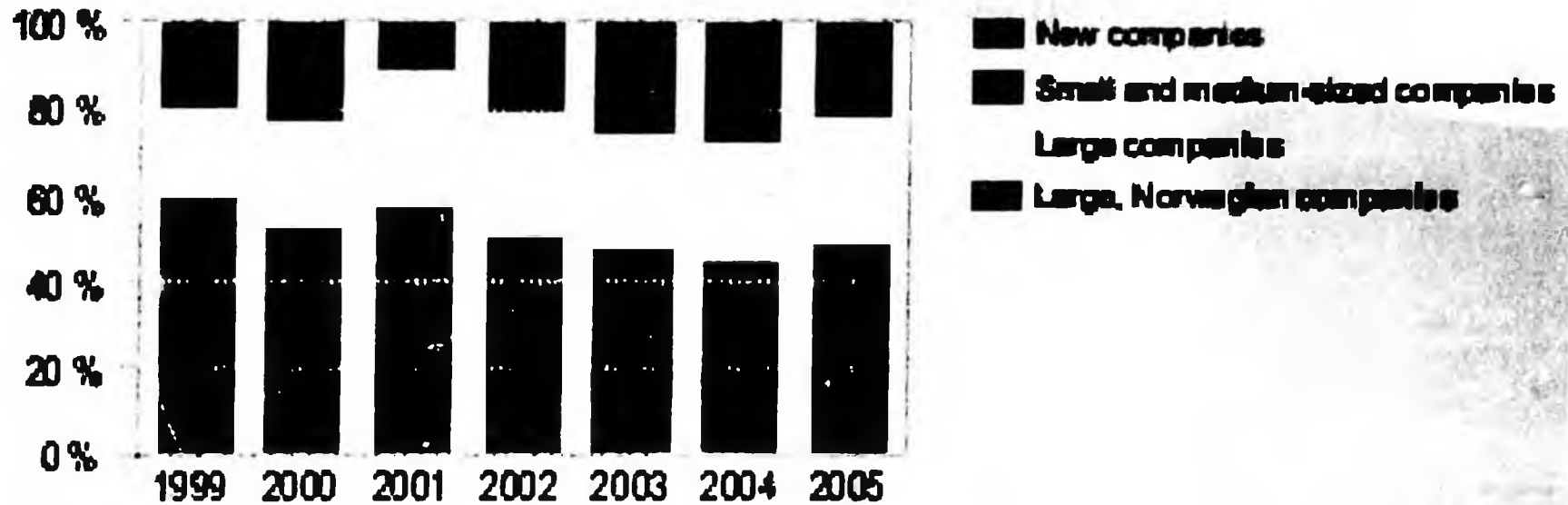


Figure 3.8 Exploration costs in production licences on the Norwegian continental shelf, distributed according to the size of the companies

(Source: Norwegian Petroleum Directorate)

Denmark Summary

- **Denmark requires data disclosure at field level**
 - Field development plans
 - Annual data / statistical analysis
 - Tax returns
- **Disclosure to**
 - Danish Energy Authority
 - Fiscal authorities
- **Publication of some detailed plus aggregated information**



Denmark

Field listing of annual capital investments .. both historical ..

Table 7.4 Investments, DKK million, nominal prices

	2002	2003	2004	2005	2006*
Cecile	223	660	309	(18)	4
Dagmar	-	-	-	-	148
Dan	437	943	750	750	684
Gorm	242	107	108	291	304
Halldan	2,412	1,779	1,124	683	1,293
Harald	0	4	22	53	1
Kraka	3	-	2	-	-
Nini	285	1,288	319	163	19
Roar	-	-	-	-	-
Rolf	-	37	4	-	1
Siri	111	406	425	73	140
Skjold	5	77	8	11	4
South Arne	849	764	762	310	451
Svend	223	-	-	-	-
Tyra	85	305	459	1,020	1,520
Tyra Southeast	569	82	96	45	-
Valdemar	(1)	200	52	553	992
NOGAT pipeline	-	766	664	12	-
Not allocated	31	(31)	2	5	97
Total	5,475	7,386	5,105	3,951	5,658

*Estimate

Denmark

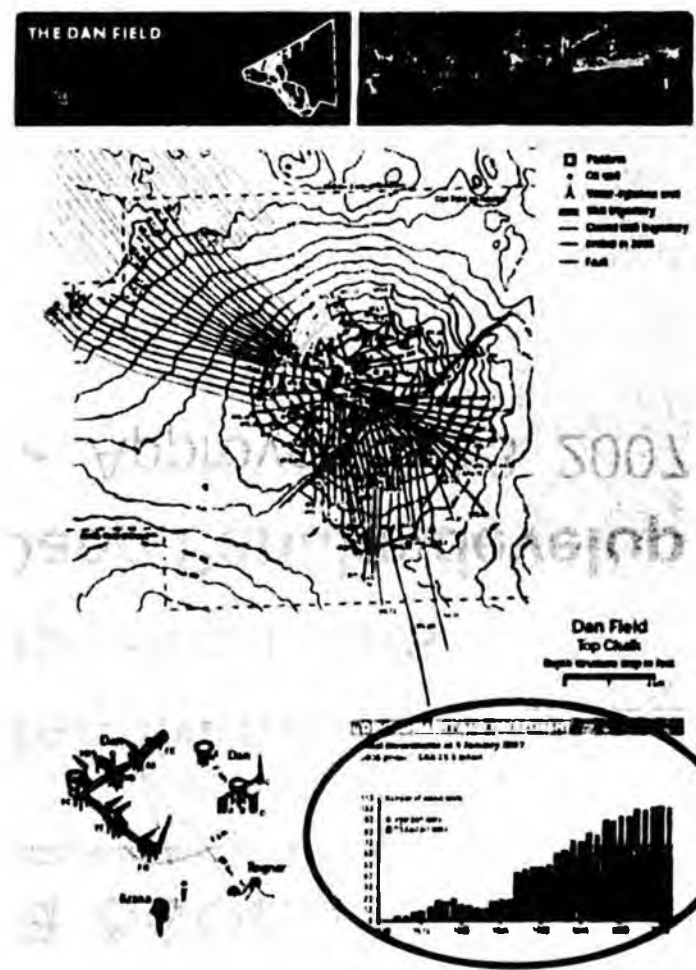
.. and projected

Table 7.5 Estimated investments in development projects, 2007-2011, DKK billion, 2006 prices

	2007	2008	2009	2010	2011
Ongoing and approved					
Adda	-	0.1	0.6	-	-
Alma	-	0.6	0.5	-	-
Beje	-	-	-	0.8	-
Cecilie	-	-	-	-	-
Dagmar	-	-	-	-	-
Dan	0.9	0.6	-	-	-
Eily	0.3	1.6	-	-	-
Gorm	0.1	0.0	-	-	-
Halvdan	2.0	0.9	0.1	-	-
Harald	0.0	0.1	-	-	-
Kraka	0.3	-	-	-	-
Lulita	-	-	-	-	-
Nini	0.1	-	-	-	-
Ragnar	-	-	-	-	-
Roar	-	-	-	-	-
Rolf	-	-	-	-	-
Siri	0.3	-	-	-	-
Skjold	-	-	-	-	-
South Arne	0.8	-	-	-	-
Svend	-	-	-	-	-
Tyra	0.4	0.4	0.4	0.0	1.3
Tyra Southeast	0.5	-	-	-	-
Valdemar	1.6	0.7	-	-	-
Total	7.3	6.1	1.5	0.8	1.3
Planned	-	-	-	-	0.8
Possible	-	0.7	4.7	6.6	4.0
Expected	7.3	6.8	6.2	7.4	6.2

Denmark

Detail on field-by-field basis



REVIEW OF GEOLOGY

The Dan Field is an structural structure induced partly due to salt tectonics. A major fault divides the field into two reservoirs, which, in turn, are intersected by a number of minor faults. The chalk reservoir has high porosity, although low permeability. There is a gas cap at the field.

Recovery from the field is based on the simultaneous production of oil and injection of water. Water injection was initiated in 1979, and later water injection was extended to high sections of the field. The recovery of oil is optimized by flooding the reservoir with water to the extent possible.

PRODUCTION STRATEGY

Recovery from the field is based on the simultaneous production of oil and injection of water. Water injection was initiated in 1979, and later water injection was extended to high sections of the field. The recovery of oil is optimized by flooding the reservoir with water to the extent possible.

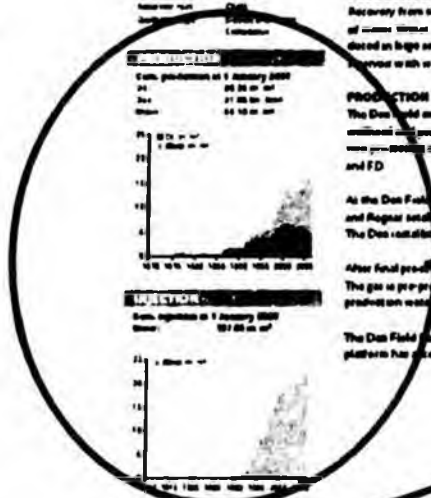
PRODUCTION FACILITIES

The Dan Field comprises an offshore platform, A, D, E, F, G, H and I, a combined offshore and onshore platform, J, a processing platform with a flare tower, K, and a processing platform with a flare tower, L and M.

At the Dan Field, there are faults on the reservoir production and injection wells, as well as the gas production wells. The Dan Field also has a gas cap at the field.

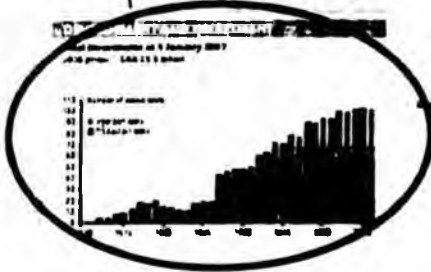
After final production, the oil is transported to shore via a pipeline. The gas is pre-processed and transported to Tvedestrand for use as fuel. The production water from Dan is used in small scale fields in the area.

The Dan Field has an onshore platform for gas processing and a platform for water injection. The platform has an onshore facility for gas processing.



Production and injection history

Reserves and EUR



Total capital investment and development drilling

Nova Scotia Summary

- Requirement for public Review of field developments
- Deep Panuke development recently submitted
 - Approved Oct 3, 2007



Nova Scotia Deep Panuke

Includes sales gas forecast ...



Table 6.1 Sales Gas Forecast

Year	P90		P50		P10		Mean	
	(10 ⁶ sm ³ /d)	(MMscfd)	(10 ⁶ sm ³ /d)	(MMscfd)	(10 ⁶ sm ³ /d)	(MMscfd)	(10 ⁶ sm ³ /d)	(MMscfd)
2010	5.7	202	5.7	201	5.7	202	5.7	201
2011	8.5	300	8.4	300	8.5	300	8.5	300
2012	7.0	249	8.5	300	8.4	300	8.2	291
2013	4.5	159	6.4	228	8.4	300	6.2	219
2014	1.1	110	4.8	171	7.7	275	5.0	177
2015	2.2	79	3.8	136	6.0	213	4.0	143
2016	1.6	58	3.3	110	4.7	168	3.4	119
2017	1.1	45	2.5	90	4.1	145	2.7	97
2018	1.1	40	2.1	76	3.3	118	2.3	81
2019	0.0	0	1.6	58	2.9	103	1.9	67
2020	0.0	0	1.5	52	2.4	86	1.6	55
2021	0.0	0	1.5	52	2.1	73	1.3	47
2022	0.0	0	1.1	45	1.7	62	1.3	45
2023	0.0	0	1.1	40	1.6	55	1.1	41
2024	0.0	0	0.0	0	1.4	50	0.0	0
2025	0.0	0	0.0	0	1.4	51	0.0	0
2026	0.0	0	0.0	0	1.3	47	0.0	0
2027	0.0	0	0.0	0	1.2	41	0.0	0
2028	0.0	0	0.0	0	1.1	38	0.0	0

Nova Scotia Deep Panuke

... and cost forecast by expenditure type

6.3.1 Development Phase Expenditures

Estimates for the development phase include costs incurred by EnCana, as operator of the Project, from the fourth quarter 2006 to first gas production, scheduled to occur in the fourth quarter of 2010.

The costs shown in Table 6.2 are for the M&NP option, and exclude any costs associated with the MOPU, which will be included as operating costs payable during the production life of the Project.

The SOEP Subsea Option would see a reduction in the cost of the export pipeline during the Development Phase. However, there would be an increase in operating costs for tariffs charged as a result of using the SOEP pipeline. At this time, these costs are not defined.



Table 6.2 Development Phase Expenditures	CS Millions 2006
EnCana Project Management & Engineering	115
Subsea	135
Export Pipeline	200
Drilling and Completions	160
<i>Subtotal:</i>	610
<i>Contingency</i>	90
Total Cost to First Gas	700

Annual operating costs, including the field centre (MOPU) lease, are estimated at \$150 million per year, +/-25%.

Nova Scotia

Deep Panuke approval explicitly requires continual update to cost information submitted with Annual Production Report

Condition 30: Submission of Economic Data

The Proponent shall inform the Board of any material changes to the cost information and production profiles that were submitted with the Development Plan. This information shall be included with the Annual Production Report. This should include details of the operating and capital expenditures for the previous two years, the current year and projections for the next two years as well as reserve revisions

Publicly Available Sources

Example detailed field cashflow available from Deloitte's subscription service

MAGNUS *BP operated UKCS*

Year	Production		Gross Revenue (\$MM)	Acycr (\$MM)	Over-Turn (\$MM)	Operating Profit (\$MM)	Company Management (\$MM)	Field Profit (\$MM)	Total (\$MM)		Field		Field Profit (\$MM)
	Oil (MMbbl)	Gas (MMcfe)							Oil	Gas	Oil	Gas	
2004	34.4	18.8	489.7	81.0	67.7	22.0	349.7	170.2	86.0	28.9	2,821.0	362.1	
2005	34.7	18.0	484.7	80.0	65.0	22.0	349.7	166.0	82.0	28.9	2,800.0	357.0	
2006	33.8	18.0	362.0	73.0	26.0	22.0	269.0	155.0	79.0	28.9	2,600.0	352.0	
2007	29.4	18.0	267.0	69.0	22.0	22.0	226.0	101.0	80.0	28.9	2,500.0	352.0	
2008	21.1	9.0	88.0	80.0	22.0	22.0	10.0	64.7	36.0	28.9	2,300.0	352.0	
2009	17.4	8.1	48.0	80.0	22.0	22.0	0.0	41.0	23.0	28.9	2,100.0	352.0	
2010	16.8	3.0	13.7	81.0	22.0	22.0	0.0	31.0	18.0	28.9	1,900.0	352.0	
2011	12.1	1.7	57.0	48.0	48.0	22.0	49.0	24.7	18.0	28.9	1,700.0	352.0	
2012	13.1	1.2	59.0	48.0	48.0	22.0	49.0	26.0	18.0	28.9	1,500.0	352.0	
2013	8.4	0.8	88.0	48.0	48.0	22.0	49.0	21.0	16.0	28.9	1,300.0	352.0	
2014	7.2	0.8	92.0	48.0	48.0	22.0	49.0	16.0	16.0	28.9	1,100.0	352.0	
2015	8.4	0.8	82.0	48.0	48.0	22.0	49.0	11.0	16.0	28.9	900.0	352.0	
2016	8.4	0.8	82.0	48.0	48.0	22.0	49.0	6.0	16.0	28.9	700.0	352.0	
2017	8.4	0.8	82.0	48.0	48.0	22.0	49.0	1.0	16.0	28.9	500.0	352.0	
2018	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	300.0	352.0	
2019	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	100.0	352.0	
2020	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2021	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2022	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2023	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2024	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2025	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2026	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2027	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2028	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2029	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2030	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2031	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2032	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2033	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2034	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2035	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2036	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2037	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2038	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2039	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2040	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2041	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2042	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2043	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2044	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2045	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2046	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2047	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2048	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2049	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2050	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2051	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2052	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2053	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2054	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2055	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2056	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2057	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2058	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2059	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2060	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2061	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2062	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2063	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2064	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2065	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2066	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2067	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2068	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2069	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2070	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2071	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2072	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2073	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2074	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2075	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2076	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2077	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2078	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2079	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2080	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2081	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2082	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2083	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2084	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2085	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2086	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2087	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2088	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2089	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2090	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2091	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2092	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2093	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2094	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2095	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2096	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2097	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2098	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2099	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	
2100	8.4	0.8	82.0	48.0	48.0	22.0	49.0	0.0	16.0	28.9	0.0	352.0	

Year	Oil (MMbbl)	Gas (MMcfe)	Production (\$MM)
2004	34.4	18.8	362.0
2005	34.7	18.0	362.0
2006	33.8	18.0	267.0
2007	29.4	18.0	88.0
2008	21.1	9.0	13.7
2009	17.4	8.1	57.0
2010	16.8</		

**Estimated Tax Impacts Under Potential Alternative Scenarios
TIE Sensitivity 1 -- No TIE Credit
FY 2008 - FY 2014**

Case (1)	ANS West Coast Price (Real 2008 \$/Barrel)				
	\$40 (2)	\$60 (3)	\$80 (4)	\$100 (5)	\$120 (6)
<u>Estimated Effective Tax Rate (Percent)</u>					
Current PPT	4.2%	10.7%	17.4%	23.6%	29.3%
ACES	9.3%	14.6%	20.6%	25.9%	30.8%
Progressivity on Gross: \$60 Trigger, 0.225% Increment	6.1%	11.9%	19.0%	25.3%	31.2%
Progressivity on Gross: \$55 Trigger, 0.225% Increment	6.1%	12.7%	20.1%	26.4%	32.4%
Progressivity on Gross: \$50 Trigger, 0.225% Increment	6.1%	13.7%	21.2%	27.6%	33.5%
Progressivity on Gross: \$45 Trigger, 0.225% Increment	6.1%	14.8%	22.3%	28.7%	34.6%
Progressivity on Gross: \$40 Trigger, 0.225% Increment	6.2%	16.0%	23.5%	29.8%	35.7%
Progressivity on Gross: \$60 Trigger, 0.25% Increment	6.1%	12.0%	19.5%	26.4%	32.8%
Progressivity on Gross: \$55 Trigger, 0.25% Increment	6.1%	12.8%	20.7%	27.6%	34.1%
Progressivity on Gross: \$50 Trigger, 0.25% Increment	6.1%	13.9%	22.0%	28.9%	35.3%
Progressivity on Gross: \$45 Trigger, 0.25% Increment	6.1%	15.2%	23.2%	30.1%	36.6%
Progressivity on Gross: \$40 Trigger, 0.25% Increment	6.2%	16.4%	24.5%	31.4%	37.8%
<u>Estimated Annual Average Tax Difference Above Current PPT (Million Dollars)</u>					
ACES	\$459	\$549	\$627	\$590	\$455
Progressivity on Gross: \$60 Trigger, 0.225% Increment	\$171	\$175	\$298	\$428	\$550
Progressivity on Gross: \$55 Trigger, 0.225% Increment	\$171	\$278	\$513	\$701	\$881
Progressivity on Gross: \$50 Trigger, 0.225% Increment	\$171	\$424	\$728	\$973	\$1,211
Progressivity on Gross: \$45 Trigger, 0.225% Increment	\$171	\$582	\$943	\$1,246	\$1,541
Progressivity on Gross: \$40 Trigger, 0.225% Increment	\$174	\$739	\$1,159	\$1,519	\$1,871
Progressivity on Gross: \$60 Trigger, 0.25% Increment	\$171	\$179	\$298	\$686	\$1,024
Progressivity on Gross: \$55 Trigger, 0.25% Increment	\$171	\$294	\$637	\$989	\$1,391
Progressivity on Gross: \$50 Trigger, 0.25% Increment	\$171	\$456	\$876	\$1,292	\$1,758
Progressivity on Gross: \$45 Trigger, 0.25% Increment	\$171	\$631	\$1,116	\$1,595	\$2,125
Progressivity on Gross: \$40 Trigger, 0.25% Increment	\$174	\$806	\$1,355	\$1,898	\$2,492

Note: Alternatives shown here move progressivity from a "net" to a "gross" wellhead basis and eliminate all TIE credits. Estimates use volumes, aggregate costs and other assumptions underlying DOR's fiscal note to HB2001.

STATE OF ALASKA

DEPARTMENT OF TRANSPORTATION AND PUBLIC FACILITIES OFFICE OF THE COMMISSIONER

SARAH PALIN, GOVERNOR

3132 CHANNEL DRIVE
PO Box 112500
JUNEAU, ALASKA 99811-2500

FAX: (907) 586-8365
PHONE: (907) 465-3900

November 2, 2007

Ms. Marcia Davis
Deputy Commissioner
Department of Revenue
P.O. Box 110400
Juneau, AK 99811-0400

Dear Ms. ~~Davis~~, *Marcia*

I am writing to recap recent email conversations between the Department of Revenue and the Department of Transportation & Public Facilities (DOT&PF) regarding the Dalton Highway (Haul Road). There were a number of questions your Department had for DOT&PF and I have outlined them below.

You have requested information regarding increased maintenance costs on the Dalton Highway as a result of increased truck traffic. You mentioned the operator contends that if the Kuparuk Crude Oil Topping Plant is not modified to produce extra ultra low sulfur diesel, the operator intends to provide the necessary diesel for slope activities by having it trucked from Fairbanks to Kuparuk. The operator estimates that the increased use of the Dalton Hwy (Haul Road) will be an additional 20 truck trips each day. I will assume this to be one-way trips.

If a deduction is not allowed for a crude oil topping plant on the North Slope, low-sulfur diesel may need to be trucked up the haul road from either Anchorage or Fairbanks. This is estimated to require roughly 20 trucks (or 3000bls) daily. What impact is this likely to have on haul road maintenance costs?

After years (decades) of marginal maintenance, over the past 4 years we have increased both our operating and capital efforts significantly. An increase of daily truck traffic on the Dalton of 50-70 trips will not result in any significant (<\$1.5 million) additional maintenance effort or cost. We do not expect the cost range to increase significantly until the daily truck traffic increases to 150 trucks (one way) a day.

Providing for the movement of people and goods and the delivery of state services.

Where are the maintenance stations located, and how long has DOT been supplying them via tanker?

We have 7 maintenance stations on the Dalton Highway, starting at Livengood at the end of the Steese Hwy and moving north.

- o Livengood
- o Seven Mile
- o Jim River
- o Coldfoot
- o Chandalar
- o Sag River
- o Deadhorse (Hwy station, airport and ARRF)

The stations (with the exception of Deadhorse to Sag) are located approximately 60 miles apart - that is the optimum distance for a road maintenance station. These stations are manned 24 hours a day, seven days a week, with the crews working seven days on and seven days off - crew members live predominantly in the Fairbanks area. To the best of my knowledge, DOT&PF has always supplied our remote maintenance stations by tanker. We bid fuel supply contracts with prices FOB each maintenance station.

I understand that fuel produced on the Slope is for the industrial uses there, and only there (although they do sell fuel to the villagers of Nuiqsut), and has no motor fuel taxes applied.

What impact will the increased haul-road traffic have on safety?

We do NOT allow double tankers on the Dalton Highway (capacity approximately 12,000 gallons) only single tankers (capacity approximately 9,000 gallons). Most fuel consumed on the slope is produced on the slope. We supply our seven maintenance stations on the Dalton out of Fairbanks via tanker with no history of mishap.

Do you know the average amount of fuel that DOT trucks up daily or how often the fuel runs happen?

We do not truck daily, but receive a delivery from private vendors on a "keep full" basis and store it in our tanks. The fuel trucks are approximately 9,000 gallons

Ms. Marcia Davis

Page 3

November 2, 2007

capacity each. During the course of a year, they make approximately 30 trips to all our stations along the Dalton and deliver approximately 45,000 gallons of gasoline and 300,000 gallons of diesel fuel and heating oil

I hope you find this information helpful. Please don't hesitate to contact me if you need additional information or clarification.

Sincerely,



**John MacKinnon
Deputy Commissioner**

cc: Ian Laing, Department of Revenue

Topping Plant

Sharon Long

From: Knudson, Kip C. [KKnudson@tsocorp.com]
Sent: Wednesday, November 07, 2007 2:46 PM
To: Sharon Long
Cc: Riley, Dan T.; Hansen, Stephen W

Sharon, hope this helps. Please call me at 907/382-0219 if you have questions.

EPA mandated the sale of ultra low sulfur diesel (ULSD – 15 parts per million sulfur content) in "urban" Alaska on June 2006. "Urban" was roughly defined as communities on the National Highway System. Sale of low sulfur diesel (500 parts per million sulfur content) was mandated in June 2007 for "urban" non-road, locomotive and marine (NRLM) uses. All diesel powered vehicles starting with model year 2007 require the use of ULSD.

Prudhoe was defined as "rural" in EPA rulemaking, but the North Slope operators signed an agreement with DEC/EPA to convert all operations (mobile and stationary) to ULSD by January 1, 2008. The following statement was written by Clint Farr, Clean Air Program at DEC:

"The original agreement between DEC and the North Slope oil producers was for the producers to refine ULSD by December 31, 2007, and then use it in all diesel burning sources. The original agreement was signed in June 2005. The first delay resulted in an amendment shifting the production date to December 31, 2008 and requiring a diesel retrofit project to capture emissions benefits commensurate with emissions gains not realized due to the delay. The amendment was signed in November of 2006. This amended agreement currently still stands." Rural Alaska and "urban" NRLM will begin the transition to ULSD in June 2010.

Tesoro Alaska began commercial production of ultra low sulfur diesel #1 (ULSD) in May of 2006. In May of 2007 Tesoro began production of ULSD #2 in a dedicated de-sulfurization unit. To date Tesoro has invested over \$64 million in unit construction and distribution system changes to manufacture and distribute up to 10,000 barrels per day of ULSD. The de-sulfurization unit can be expanded should demand exceed 10,000 barrels. Total statewide demand is not expected to exceed 10,000 barrels for several years.

Flint Hills Resources entered into a long-term ULSD supply contract with Tesoro in 2006. Tesoro is currently the only in-state manufacturer of ULSD.

Either Flint Hills or Tesoro could supply North Slope demand for ULSD.

Tesoro has not been eligible for any tax breaks for the \$64 million investment made to supply ULSD to Alaska.

Topping Plant

Sharon Long

From: Deborah Grundmann
Sent: Wednesday, November 07, 2007 10:18 AM
To: Sharon Long
Subject: FW: Topping plant

FVI
deb

-----Original Message-----
From: Sen. Charlie Huggins
Sent: Wednesday, November 07, 2007 10:17 AM
To: Deborah Grundmann
Subject: FW: Topping plant

For CH

yes

-----Original Message-----
From: Galvin, Patrick S (DOR) [mailto:patrick.galvin@alaska.gov]
Sent: Tuesday, November 06, 2007 10:35 PM
To: Dermot Cole; Sen. Charlie Huggins
Subject: RE: Topping plant

Dermot,

I agree. I'm also concerned about the prospect of the state subsidizing the building of a private refinery to compete with another private refinery already operating in the state. The idea doesn't seem to promote fair private competition.

-Pat

-----Original Message-----
From: Dermot Cole [mailto:cole@newsminer.com]
Sent: Tuesday, November 06, 2007 8:19 PM
To: Sen.Charlie.Huggins@legis.state.ak.us
Cc: Galvin, Patrick S (DOR)
Subject: Topping plant

Sen. Huggins, Commissioner Galvin:
The decision on whether or not to build a topping plant is one that private industry should make.
By not granting a subsidy to the companies, that does not mean that the state is forcing the industry to haul fuel up from Kenai.
I don't see why the state should subsidize this to the tune of \$150 million, which I think is the figure cited by the commissioner.
For the state to "participate," there should be some justification.
What is it?

Thanks,
Dermot Cole
Fairbanks News-Miner



Roger D. (Dale) Summerlin
Vice President
Health, Safety & Environment

P.O. Box 100360
Anchorage, AK 99510-0360
Phone 907.263.4662
Fax 907.263.4438

October 4, 2007

Mr. Tom Chapple, Director
Alaska Department of Environmental Conservation
Division of Air Quality
555 Cordova Street
Anchorage, Alaska 99501-2617

Dear Mr. Chapple:

Please find below a summary of the 'North Slope Ultra Low Sulfur Diesel Transition Agreement' progress meeting between representatives from ConocoPhillips Alaska, BP Alaska and the Alaska Department of Environmental Conservation held at ConocoPhillips' Anchorage office on September 27, 2007. Per the agreement, ConocoPhillips is to provide a progress report to your office in March and September of each year through 2008 to keep the Alaska DEC up to date on the status of the ULSD project. As agreed during the September 27 discussion, the meeting satisfied the requirement for the September 2007 progress update. Also noted in the meeting, Mr. Batch was to provide you an update on BP's ULSD storage and distribution progress separately. The attached documents included in this transmittal are the handout materials provided at the meeting and a block flow diagram, both current and future, for storage and distribution at Kuparuk.

The ULSD storage and distribution facility project at Kuparuk is on schedule and on track to be put into operation in December 2008.

The ULSD hydrotreater engineering is very well advanced and is on hold pending the outcome of the AFE approval. The AFE approval process began in September 2007, and once the AFE is approved the project can be quickly restarted. However, the recent exclusion of the tax credit/deduction for topping plants in the proposed tax legislation intended to replace the Alaska Petroleum Profits Tax makes the ULSD hydrotreater project uneconomical as compared to an importing alternative. Until ConocoPhillips fully understands how the State intends to treat this project from a fiscal perspective, they will not be able to determine if installing the hydrotreater is the optimum solution to meet their North Slope ULSD needs and hence unable to approve the AFE. If the AFE is not approved by the end of the year, then it will not be possible to make the 2009 sealift window and the hydrotreater project will be delayed another year. ConocoPhillips agreed to get back in touch with the Alaska DEC in early November to provide an interim progress report.

Planning and logistics are in progress to have ULSD hauled to the Slope beginning January 1, 2009. Commercial arrangements with suppliers have not been made to date, however discussions

Page 2
October 4, 2007

are underway. One concern raised was the lack of haul capacity. We do not believe there are adequate tanker trucks available to haul an estimated minimum of ten (10) truck loads of diesel daily. This will require an estimated minimum of 30 tanker trucks. New trucks will need to be built.

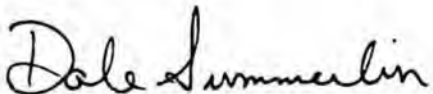
The three (3) ConocoPhillips emission reduction projects estimated at \$900,000 were discussed. A meeting will be scheduled in late October to discuss further emission reduction projects.

ConocoPhillips representatives again expressed their concern that the proposed tax legislation as written is counter productive for the environment as it does not encourage the development of facilities on the North Slope to reduce emissions.

Additionally, the transport of ULSD from southern Alaska to the North Slope generates an increased risk of hydrocarbon spills. The use of rail car and trucking transport to move/load/discharge ULSD across six boroughs (including a minimum of ten trucks daily on the Dalton Highway) contributes to this spill risk. It is ConocoPhillips' desire, and we believe it is the Alaska DEC's desire, to make ULSD on the Slope and eliminate hauling/importing ULSD.

Please do not hesitate to contact me if you have any questions.

Sincerely,



Roger D. (Dale) Summerlin

cc: Mr. Bob Batch - BP
Commissioner Larry Hartig - ADEC
Mr. Georg Storaker - CPAI

CS Retains

- **Administrative tools to administer PPT and forecast more accurately**
- **Exempt auditors** CS 9
- **Information gathering including more freq. filings**
- **Information sharing DOR to DNR and DNR to DOR each maintaining the other's confidentiality requirements**
- **Modified TIE credits (CS Sec. 13)**
- **1000.00/ day penalty for failure to file (CS 14 gove sec 47)**
- **Must file whether or not tax is due (CS14)**
- **Explorer/producer not producing must file (cs16 gov. 48)**
- **Powers of DOR (cs 17 gov 49)**
- **Electronic Filing (cs 18 gov 51)**
- **Lease expends ARE (cs 19 gov 56)**
- **Direct cost (cs 20 gov 57)**
- **Expendituress ARE NOT (cs 21 gov 58 DRR ,Corrosion –"SB80", Topping Plant)**

Constitutional & privacy issues need to be look @ re Disclosure of tax info

NOT IN CS

Tax rate

Progressivity trigger lowed to \$30

Alternative Minimum Tax (10% gross floor)

Spreading Credits over 2 years

Statute of Limitations extension

Tax credit fund

Changing tax calculation periods

Slew of language corrections and conformity issues throughout bill

Constitutional & privacy issues need to be look @ re Disclosure of tax info

Treatment capital and operating credits and carry forwards

Treatment of tax exempt entities & transferable certificates

DNR Commissioner authority re tax credit eligibility

Ring Fencing

TIE Credit Comparison PPT vs CSSB2001(RES)

	Capital Spend in millions	CSSB 2001(RES)	
2001 April 1-Dec 31	\$1,207,000,000.00		
2002	\$1,298,700,000.00		
2003	\$1,188,800,000.00		
2004	\$1,136,900,000.00		
2005	\$1,268,000,000.00		
January 1 - March 31, 2006 (est)	\$416,325,000.00		
	\$8,511,725,000.00	\$600,000,000.00	Difference
Amount of eligible credit	\$1,302,348,000.00	\$120,000,000.00	\$1,182,348,000.00

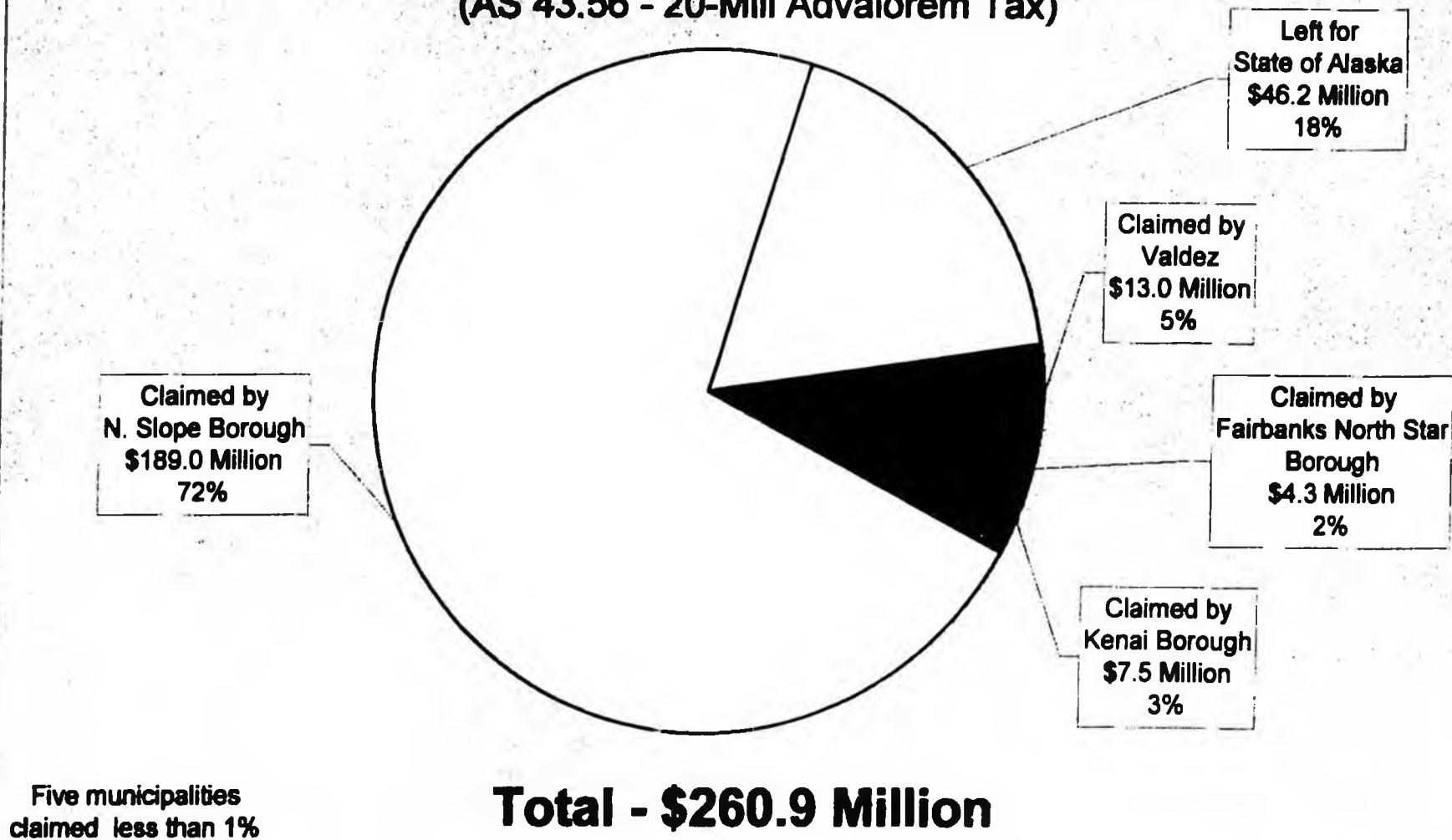
Year	TIE estimate at \$60 ANS west coast	PPT Amount of Credit Remaining		CSSB2001(RES) 10% of Nonproducer capital spend from 3/31/06 to 1/1/08 ¹
2007	\$181,700,000.00	\$1,120,648,000.00	\$181,700,000.00	<div style="font-size: 2em;">{</div> <div style="text-align: right;">\$120,000,000.00</div>
2008	\$213,700,000.00	\$906,946,000.00		
2009	\$188,100,000.00	\$718,846,000.00		
2010	\$197,500,000.00	\$521,346,000.00		
2011	\$190,200,000.00	\$331,146,000.00		
2012	\$198,000,000.00	\$133,146,000.00		
2013	\$133,148,000.00	\$0.00		
Total	\$1,302,348,000.00		\$301,700,000.00	Difference \$1,000,648,000.00

¹The amount of eligible credit is 10% of the amount actually expended by a non-producer from 3/31/06 to 1/1/08

In order to claim a credit of \$120,000,000 a non-producer would have to spend \$1,200,000,000 from 3/31/06 to 1/1/08

PPT pays out 1.3 B
 RES " " 181 M
 SRES " " _____

**2005 State 20-Mill Levy
Oil & Gas Property Tax GF Revenue
(AS 43.56 - 20-Mill Advalorem Tax)**



The state levies a 20-mill tax against oil and gas property. A municipality that has O and G property located within its borders may also levy a tax on those properties. This local tax amount is subtracted from the total of the state's 20-mill tax.

by G. Wilkew's Office

All posted on LBFA website

LBFA Handbook
Petro v Minerals
[1 HR presentation]

AK Gas - uneconomic unless we
liquefy it

Proposed revisions to the PPT

October 18, 2007
Presentation to

The Alaska Legislature

- 1 well = 5.8 million
1 million CF = 1 billion
9
- 6000 gas = 1 barrel oil

Even Alberta 140 Billion barrels
of heavy oil

- AK compares more to
① Trinidad, ② Newfoundland
= smaller resource potential
= smaller population

Overall Recommendation

I would strongly recommend **not** to make any changes in the PPT law, other than the transparency provisions.

Changing taxes substantially every year creates an image of serious fiscal instability that could damage investor confidence in Alaska.

Overall Recommendation

The current law already provides for a review mechanism by 2011.

*will have
- a couple audits
would know how
it was working*

The year 2011 is the appropriate time to make such revisions because at that time the first audits will have been completed and final and reliable information would be available.

from US
to go out of
Alberta

Current System

Table 5.26. WEST SAK
Undiscounted Government Take (Income only)

WTI US \$	WTI Can \$	Gas Price Can \$	Heavy oil price Can \$	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	\$1.89	\$14.35							60.38%
30	34.09	\$2.84	\$24.32			60.22%	59.56%	59.31%	59.27%	59.19%
40	45.45	\$3.79	\$34.28	59.68%	59.60%	59.54%	59.49%	59.45%	59.21%	59.09%
50	56.82	\$4.73	\$44.25	59.81%	59.81%	59.83%	59.72%	59.62%	59.66%	59.77%
60	68.18	\$5.68	\$54.22	60.66%	60.66%	60.64%	60.69%	60.83%	60.98%	61.09%
70	79.55	\$6.63	\$64.18	61.83%	61.87%	62.02%	62.18%	62.34%	62.45%	62.53%
80	90.91	\$7.58	\$74.15	63.24%	63.39%	63.53%	63.68%	63.80%	63.88%	64.02%
90	102.27	\$8.52	\$84.11	64.74%	64.88%	65.02%	65.15%	65.24%	65.36%	65.53%
100	113.64	\$9.47	\$94.08	66.21%	66.35%	66.50%	66.59%	66.70%	66.86%	67.04%

Discount rate
5%

Current System

Table 5.27. WEST SAK
5% Discounted Government Take (Income only)

WTI US \$	WTI Can \$	Gas Price Can \$	Heavy oil price Can \$	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	\$1.89	\$14.35							64.33%
30	34.09	\$2.84	\$24.32			69.77%	63.56%	61.41%	60.49%	59.82%
40	45.45	\$3.79	\$34.28	64.13%	62.57%	61.60%	60.94%	60.45%	59.75%	59.31%
50	56.82	\$4.73	\$44.25	61.80%	61.32%	60.95%	60.44%	60.00%	59.82%	59.76%
60	68.18	\$5.68	\$54.22	61.83%	61.48%	61.15%	60.96%	60.95%	60.96%	60.91%
70	79.55	\$6.63	\$64.18	62.50%	62.28%	62.29%	62.31%	62.35%	62.32%	62.25%
80	90.91	\$7.58	\$74.15	63.65%	63.66%	63.68%	63.71%	63.70%	63.63%	63.66%
90	102.27	\$8.52	\$84.11	65.01%	65.02%	65.05%	65.06%	65.02%	65.03%	65.12%
100	113.64	\$9.47	\$94.08	66.35%	66.38%	66.43%	66.39%	66.39%	66.47%	66.58%

Current System

The current system is designed to be sensitive to costs and thereby make the investment in heavy oil developments attractive.

The current system was is also designed to be price progressive.

Current System

The PPT credits encourage investments by new investors in new oil and gas exploration and development and to encourage re-investment by existing companies. The PPT is therefore a consolidated system.

The main goal is to reduce the decline of oil production.

sp get more oil in the pipeline

Transparency

The transparency provisions related to cost projections, publication of data, short term audits and an exempt class for auditors seem good provisions.

They should be strongly supported.

These changes can be implemented now.

- not changing fiscal terms
- excellent to
- make auditors exempt
- stronger Admin

*Pedro's
Reports
from last
round*

PPT amendments

In case the Alaska Legislature decides that it wants to change the PPT anyway, I would advise basing such amendments on my earlier recommendations contained in the reports of:

- February 14, 2006
- March 5, 2006 and
- May 1, 2006

prev. recommendation

PPT Amendments

In my February 14, 2006 report I recommended a 25% PPT rate.

had proposed 25/20 rate credit

Since, this recommendation was made government takes have increased in the US GOM and Ireland and several developing countries. Alberta will also increase government take as a result of the royalty review.

I therefore reconfirm this recommendation

Govt takes going up all over the world - still advocate 25%

PPT Amendments

In my February 14, 2006 report I did **not** recommend the so-called **clawback** provision. Internally, I advised strongly against this provision. It does not make sense to reward a company for past investments.

Therefore deleting the Transitional Investment Expenditures credits is a good step.

*delete
TIE credits*

*Fiscal systems
must be based
on "from now
forward"*

*Progressive
feature*

*"Hybrid"
system (like Pika)
already proposed*

PPT Amendments

In my March 5, 2006 report (which was written after the 20/20 concept had been decided by the Governor) I recommended:

- A price progressive Basic Production Tax based on the gross value of production **in addition to** the PPT.
- The price progressive Basic Production Tax would be deductible from the PPT.

*- basic Prod tax
based on GROSS
- plus progressive*

strongly
recommends
Hybrid 5/11

PPT Amendments

The price progressive Basic Production Tax was based on the following formula:

$$\text{BPT rate} = (\text{WTI} - 50) \times 0.25\%$$

At the current price of \$ 84 per barrel WTI this would be equal to 8.5% on the gross value of oil at the production point.

Be not
"wishy washy"
do a real
gross + net

(not Pat's
"hidden" gross)

(8.5% on gross
+ 25% on net)
Pachas
Hybrid system

Implemented in Alberta

PPT Amendments

I believe that price progressive features based on the gross value of the production are more effective than features based on net.

I recently recommended a similar severance tax to the Alberta royalty review panel and this recommendation was accepted. The Alberta Government is now considering these recommendations.

PPT Amendments

The current progressive feature in the PPT law based on the net value is an ineffective mechanism. It is highly unpredictable and subject to cost verification difficulties. Bringing the price down from \$40 to \$ 30 is a relatively weak measure. I do not recommend this.

PPT Amendments

"I proposed a
level playing field"
+ that's good policy

I therefore reconfirm my
recommendation for a price
progressive feature based on gross
in addition to the 25% PPT Rate.

However, such a feature would
need to have a modifier in the
formula in order to soften the
impact on heavy oils.

modify
for heavy oils

get realistic
about govt take
for Gas !!

PPT Amendments

The May 1, 2006 report recommended the Gross Revenue Exclusion ("GRE") for pipeline gas (not for condensates and liquids) of 64% of the gross value of the prior to the application of the PPT for gas other than from Cook Inlet.

(for all the gas)

Gas that needs to be transported over long distances has very different economics than oil.

cannot apply
to gas as oil
transportation
system too expensive

Trinidad & Tobago
Malay
Indo
Qatar

← all understand
tax for gas can't
be the same as oil: different economics

PPT Amendments

Most jurisdictions that need to export gas over large distances have a government take that is lower for gas than for oil. If Alaska wants to compete with a gas project internationally, it has to start with a reasonable fiscal system for gas.

I therefore reconfirm my GRE recommendations.

Failure to forecast cost increases

Much discussion took place about the so-called failure to forecast cost increases. In this respect I like to emphasize that I provided the Legislature ample and precise warning about cost increases. The following three slides are repeat slides of my presentations in 2006.

May 10, 2006 slide: Alaska Gas Project

Cost overrun risks

The economic evaluations are based on a \$ 21 billion project as originally presented.

However, cost have already escalated significantly, in particular steel prices and regional escalation in Alberta.

"pipeline in trouble
cause WORLD has changed"

May 10 slide: Alaska Gas Project

Huge risks

The combination of gas price risk and cost overrun risk creates a possibility that the project may not be built over the next decade even with a stranded gas contract.

① price itself
② structure of market in N. America

today gas prices on BTU basis are only 35-40% of oil

- electricity generation can be produced by clean coal which is competing w/ gas

- gas = \$1 to 2 per million BTU
oil =
per barrel \$80 =

Charlie statement

did you say "Gas Pipeline is not feasible"

I invited Pedro to comment

PvM "deeply concerned about pipeline"

not economic @ @2001 costs now doubled

today we have economics that prove line is uneconomic

June 15 slide: Risk Assessment: Summary

In summary the view of EconOne is:

50% cost overrun – very low probability

FIF low gas price – very low probability

Project uneconomic – very low probability

My view is:

50% cost overrun – very likely

FIF low gas price - fair probability

Project uneconomic – fair probability

Failure to forecast cost increases

Despite the fact that I predicted strong cost increases generally and internationally, there was no evidence in early 2006 of strong local inflationary pressures on the North Slope (as compared to Alberta, for instance).

- "cannot have it both ways"

Galvin —
now accepts there are huge cost increases —

in Mexico quadrupled (.5M²³ day for deep water)
Alberta (increases too) 2nd

Should do audit first then say whether → On North Slope didn't see great cost increases —

Failure to forecast cost increases

Therefore, I believe that it is imperative to carry out sound audits prior to reaching any conclusions on whether costs were significantly under estimated or not.

It might very well be that companies over-declared their costs for their first PPT declarations and that after proper audits the revenues to Alaska will be revised upward.

Imperative
to do audits
first ~~of~~
declaring
enormous cost
increases

- Co's could have over declared
- Always the year it works w/ fair law; co's push boundaries

Failure to forecast cost increases

I am concerned about the fact that the earlier PPT law weakened the level of interest for late payments in 43.55.020(g). The current bill maintains this.

So this is an added incentive to over declare costs.

penalty of over declaring must be increased — put it in new bill

10% floor on large fields

The PPT is designed as a consolidated tax. Only in this way, does the tax promote the re-investment in Alaska.

The 10% floor on large fields turn the PPT into a tax that is essentially ring-fenced for the large fields. This is an administrative nightmare as is evidenced by the amendment of 43.55.165 (h) and it also removes the benefits of promoting re-investment in Alaska by the large corporations.

This makes no sense. I would strongly recommend not to apply this provision.

this is a political move doesn't really do anything for us.

Do a "straight up" gross + net system or just forget this floor "it makes no sense"

tax credits over two years

This is a silly an unnecessary provision.

The policy is to encourage new oil and gas developments on the North Slope. There is no change in overall government revenues over time, if credits are allowed over two years rather than one. However, it is a much stronger incentive to give the credits in the year the investments are incurred.

I would strongly recommend not to apply this provision.

for small
co's it's REALLY
important to
give full credit -
"Just a bean
counters attempt
to look smart"

“corrosion” issue

*figure
could be
50¢ - w/new
info can adjust*

This is great politics, but difficult administration. Essentially, the PPT tax collectors would be placed in a constant battle to determine these costs.

The corrosion issue was already fixed in the PPT law by making the first \$ 0.30 per BOE capital costs non-deductible. This was in lieu of the corrosion costs. This is easy to administer. If this overall figure seems too low, than this figure can be changed. Also an amount for non-deductible operating costs can be added.

Extra incentives for exploration

Beyond the 20% capital investment credit, there is in my view no need for further incentives in exploration.

don't give
10 or 80 or 90%
of exploration
wells to oil cos
(which is what all
the credits add
up to)

“Joint Administration”

*share info
but don't
set up joint
administration*

The Bill provides for more exchange of information between DNR and DOR. This is good.

However, the bill seems to implement some type of joint administration by DNR and DOR of the PPT. This is unnecessary and very confusing and will lead to bottlenecks.